UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units	)	**Docket No. EPA–HQ–OAR–2013–0602**
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Comments of Sierra Club and Earthjustice

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I. Introduction

Global climate change is the biggest environmental, social, and political challenge of our time. Unless we act swiftly and immediately to curb emissions of heat-trapping pollutants, especially carbon dioxide ("CO_2"), we will be unable to mitigate the worst of effects of this crisis: rising sea levels, mass plant and animals extinctions, an increasing scarcity of crucial natural resources, a greater frequency of extreme weather events, the spread of toxins, pests, and pathogens, widespread displacement of peoples, and unprecedented social upheaval. Fossil fuel-fired power plants, or electric generating units ("EGUs"), are the single largest source of CO_2 emissions in the United States and represent a significant percentage of global emissions. Any strategy to minimize the impacts of climate change must address CO_2 emissions from fossil fuel-fired EGUs in the United States.

We applaud EPA for proposing the Clean Power Plan ("CPP"), which represents the first direct limitations on CO_2 emissions from the U.S. electric sector. The CPP comes at a critical moment in the fight against climate change. The United States and China, the world's two biggest carbon polluters, recently announced a joint agreement to cut CO_2 emissions significantly over the next decade and a half. For the U.S. to be a climate leader on the world stage and meet its international commitments, the CPP and similar efforts are crucial. The domestic electric sector is also undergoing a major shift away from coal-fired generation in favor of lower-emitting resources, with wind and solar generation experiencing rapid growth and a steep decline in costs. The CPP both reflects the changing nature of the utility sector and helps advance the momentum toward cleaner generation that already exists.

The combination of four building blocks that constitute EPA's proposal—heat rate improvements at coal-fired EGUs, reduced utilization of coal plants in favor of lower-emitting sources, increased development and use of non-emitting resources, and energy efficiency investments—is cost-effective, technically achievable, and well-tailored to reflect the complex and interconnected nature of the electric system. As such, EPA's plan is an appropriate exercise of the agency's authority under section 111(d) of the Clean Air Act. However, the urgency of the climate crisis and the imperative for the U.S. to lead global efforts to reduce climate pollution demands stronger action. EPA must strengthen the CPP and ensure that the rule is maximally effective.

In our comments, we discuss the rule's legal ramifications and propose a suite of improvements to achieve greater CO_2 reductions. We also address a number of additional topics, including compliance and enforcement issues in state plans, environmental and economic justice considerations, grid reliability, and others.

II. EPA's Obligations Under Section 111(d)

Section 111(d) of the Clean Air Act directs EPA to issue emission guidelines for existing sources of air pollution that endanger the public health or welfare once EPA has issued new source standards for that pollution under section 111(b). States then implement EPA's guidelines through federally approved plans, which include performance standards for covered sources of pollution. These standards must reflect EPA's determination of the best system of emission reduction, or "BSER," that is adequately demonstrated, taking into account the energy requirements and non-air environmental impacts of affected sources. While the statute also requires EPA to consider costs associated with BSER, courts will not reject a BSER determination on economic grounds unless it entails costs that are "exorbitant" and would effectively cripple the regulated industry.

EPA has proposed two alternative approaches for determining the BSER. We offer additional support for EPA's second approach—BSER as the combination of building block 1 plus the reduced utilization of affected sources, quantified in specific amounts from the measures comprised in building blocks 2, 3, and 4. Specifically, the amount of generation from the increased utilization of natural gas combined cycle ("NGCC") units (building block 2) would determine a portion of the amount of reduced generation from affected fossil fuel-fired steam EGUs, and the amount of generation from the use of renewable energy and avoided emissions through demand-side energy efficiency (building blocks 3 and 4) would determine a portion of the amount of the generation reduction for all affected EGUs—both coal-fired steam EGUs and NGCC units. Under this approach, enforcement would be simpler and more straightforward because affected sources would be accountable for the required emissions reductions.

CO_2 emissions reductions at fossil fuel-fired EGUs can be achieved by reducing both the EGU's emission rate and its electricity output. Heat rate improvements at affected EGUs are aimed at reducing these sources' emission rate; redispatch to existing and under construction NGCC units, renewable energy, and demand-side energy efficiency are aimed at reducing affected sources' output and thus their overall mass CO_2 emissions. All of the emission reductions measures under consideration, whether implemented directly at the affected source or beyond the source, translate into emissions reductions *from* such sources. The measures under the four building blocks are effectively "at the unit" measures that reduce affected EGUs' utilization, because these measures are being and can be implemented or sponsored by owners and operators of affected sources. EPA should therefore set the stringency of the emission guideline based on the complete universe of those measures.

Even though EPA's proposal contemplates including both fossil fuel-fired units and stationary combustion turbines in a single category (codified under a new Subpart UUUU), failure to include oil- and gas-fired ("O&G") steam EGUs and NGCCs in building block 1 implies that these units are not subject to emission reduction requirements. Therefore, we urge EPA to incorporate O&G steam EGUs and natural gas-fired units, both NGCCs and simple cycle combustion turbines ("CTs"), in building block 1, and to reformulate its BSER approaches accordingly. Under EPA's second BSER approach, the BSER would include, first, building block

1—heat rate improvements (and other capital investments such as turbine blade replacements) on all affected fossil fuel-fired EGUs, and second, a reduced utilization component. The reduced utilization component would comprise limiting the dispatch of fossil fuel-fired steam EGUs by the amount of available existing NGCC capacity in 2020, and thereafter limiting the dispatch of all fossil fuel-fired EGUs by the amount of available renewable energy and energy efficiency.

In the sections that follow, we establish that each of EPA's proposed BSER building blocks, if strengthened in the ways that we suggest, are adequately demonstrated and will not impose unreasonable costs on the U.S. electric power generation industry. We note, however, that EPA is not proposing that each of the measures in its proposed system of emission reductions be met. Instead, EPA proposes a formula that identifies one low cost mix of measures that can achieve significant emission reductions and proposes to allow sources, states and groups of states flexibility in achieving equivalent reductions. It is this objectively determined formula that must meet the statutory tests described above.

III. The Building Blocks

A. Block 1: Heat-Rate Improvements

Heat-rate improvements ("HRI") at individual fossil-fired units are a cost-effective and well-demonstrated method of reducing CO_2 pollution. Through enhanced operation and maintenance ("O&M") practices and targeted equipment upgrades, plants can reduce the amount of fuel needed to generate each megawatt-hour of electricity, thus reducing CO_2 emissions. EPA expects that coal-fired EGUs can achieve a six percent reduction in emission rates (a figure it admits is conservative) through a combination of O&M improvements and equipment upgrades. However, Sierra Club conducted a study of 52 randomly-selected coal plants and determined that simply by meeting their best historical performance averaged over a one-year period, coal plants can achieve at least a six percent HRI through O&M practices alone. Equipment upgrades add an additional four percent HRI, and the data indicate that few units have already undergone the kinds of upgrades associated with the largest reductions. Therefore, EPA should revise Block 1 to assume a ten percent rather than six percent emission reduction through HRI at coal plants.

As noted above, we also urge EPA to include HRI at O&G steam EGUs and NGCCs in its Block 1 reductions. Our data illustrates that O&G steam units can benefit from the same kinds of O&M and equipment upgrades that would reduce emissions from coal plants. While NGCCs tend to be better operated than steam EGUs, there are still cost-effective equipment upgrades available that will reduce CO_2 emissions from these facilities. Finally, EPA should cover CTs and all other fossil-fired EGUs in the CPP, regardless of capacity factors or function.

B. Block 2: Redispatch of Coal-Fired and O&G Steam Units

Under Block 2, EPA calculates the emission reductions that could be achieved by reducing dispatch of coal-fired and O&G steam EGUs in favor of other resources. Specifically, the agency determines the amount of unused NGCC capacity that is available in each state up to a 70 percent utilization rate, then calculates the amount of coal and O&G steam generation that could be reduced if the state were to use that excess NGCC capacity for baseload generation. Reduced utilization of coal- and O&G-steam units is an appropriate element of BSER, since it is achievable, technically demonstrated, and economically reasonable.

We have serious concerns about gas-fired generation. Not only does natural gas combustion generate large quantities of CO_2, it produces significant upstream methane emissions that partially—and perhaps entirely—offset the climate benefits that might otherwise accrue from reducing coal combustion. Furthermore, the extraction of natural gas, especially through unconventional methods such as hydrofracking and tight-gas extraction, have significant water quality and land use impacts.

However, EPA is clear that Building Block 2 does *not* mandate redispatch from coal to gas. Rather, it simply quantifies the emission reductions that *could* be achieved through coal-to-gas switching and leaves it up to the states to achieve these reductions in whatever way is feasible. Moreover, Block 2 represents an effective proxy for the reductions available to the electric sector through coal plant retirements. Coal-fired EGUs have been retiring at a swift clip in recent years, a trend that economists predict will continue apace over the next decade. Although the CPP's emission targets do not directly address coal retirements, Block 2 is premised on curtailed use of coal-fired electricity and the emission reductions it quantifies are roughly tantamount to those that can be expected from retirements during the plan's timeframe.

Emission reductions calculated under Block 2 can be increased if the following three changes are considered. First, EPA must account for near-term coal retirements in its target-setting exercise under Block 2. The agency's goal calculations include data from coal plants that have either retired in 2012 or will have retired by the time the compliance period begins. There is no justification to include these units in the goal calculations, and removing them would ensure that the coal fleet actually in existence as of 2020 will reduce its emissions accordingly. To achieve this, EPA should recalculate its state goals at the time each state submits its plan to the agency. Second, EPA's current approach reduces dispatch of coal-fired EGUs (on the one hand) and O&G steam units (on the other) in proportion to their existing ratios of generation. Instead, the agency should revise its formula such that the higher emitting source group is displaced first, and the lower-emitting group is curtailed only if there is additional NGCC capacity after coal is entirely displaced. Third, the current proposal calculates redispatch on a state-to-state basis. This produces differences among the states based on the amount of available NGCC capacity from one state to the next. If EPA were to organize the states into redispatch regions, it would smooth out these disparities and provide for greater reductions, while also reflecting with greater accuracy the interstate nature of the electric sector.

C. Block 3: Increased Utilization of Renewable Energy

We strongly support the use of renewable energy ("RE") as an element of the CPP. Zero-carbon resources—particularly onshore wind, utility-scale solar, and distributed photovoltaic ("PV") solar—have been generating electricity for decades and have experienced dramatic price decreases over the last decade, with the steepest reductions occurring in the last few years. These resources are at or near price parity with fossil generation in many areas of the country and continue to exhibit very rapid growth in market penetration. Although there is some uncertainty about the future of certain tax incentives that have benefited renewable resources in recent years, such as the production tax credit and the investment tax credit, we expect that wind and solar will remain competitive products into the foreseeable future through robust financing mechanisms, research and development gains, and regulatory pressure through the CPP and other state and federal programs.

RE is therefore an appropriate—and crucial—component of BSER. In fact, we believe that EPA has significantly underestimated the extent of RE penetration that is achievable nationwide and in individual states. Building Block 3 currently sets state-level renewable goals by calculating regional averages of the renewable portfolio standard ("RPS") targets in states that have such programs. It then determines the amount of yearly growth needed in each state to meet that regional average. The agency has proposed an alternative formulation for Block 3 that bases the state RE targets on the lesser of two values: 1) a national benchmark that calculates the development of different renewable technologies in 16 leading states as a percentage of those states' resource-specific technical potentials; and 2) the results of integrated planning model ("IPM") runs calculating the market potential in each state for different renewable resources based on development cost reductions.

Both of EPA's approaches must be improved. The primary approach assumes that an average RPS target represents a reliable RE potential for states in that region, when, in fact, this target merely reflects the political will that states in each region have thus far exerted toward RE development. Hence, a region such as the Southeast has the lowest average of all regions (based on the RPS of just one state), even though it has an above-average technical potential for renewable generation. Furthermore, the regional RPS averages generate RE targets for many states under Block 3 that actually fall below the legally-enforceable RPS goals in those states. In addition to a number of flawed assumptions that result in truncated targets, the Block 3 calculations are based on the unfounded assumption that RE generation will remain constant between 2012 and 2017. As for the alternative approach, it selects without justification the *lesser* of the two calculated benchmarks for each state. It also assumes a qualitative equivalence between the two benchmarks, even though IPM modeling offers a much more analytical and input-based estimate of a state's renewable potential than the alternative, which is based on a rather simplistic ratio of development-to-technical potential for different technologies using a single year's data. And even the IPM-modeled benchmarks suffer from a paucity of data for many resources and outdated cost assumptions that significantly underestimate the market potential for various renewable resources.

To improve Block 3, EPA has a number of options available. First, it could retain a regional RPS-based approach but correct the flaws we identified above and establish an appropriate RE "floor" that each state must achieve regardless of the regional RPS average. Second, it could conduct a new round of IPM modeling using the best and most updated cost assumptions and resource-specific data to determine the true RE market potential in each state. The Natural Resources Defense Council ("NRDC") has sponsored its own analysis of Block 3 using IPM modeling that corrects many of the errors in EPA's proposal, and we urge the agency to consider closely the results of NRDC's study. Finally, the Union of Concerned Scientists ("UCS") has proposed a feasible and effective approach to Block 3 that would nearly double the amount of renewable generation achieved through the CPP relative to either of EPA's approaches. The UCS model would require states to maintain (starting in 2017) the level of RE growth they achieved between 2009 and 2013. It would also establish an annual growth floor of 1.0 percent and annual growth ceiling of 1.5 percent, as well as a total statewide ceiling of 40 percent market penetration. We are confident that with available financing mechanisms, rapidly declining costs of renewable technologies, and appropriate regulatory pressure, states will have little trouble sustaining a consistent level of RE growth between 2017 and the end of the CPP compliance period.

Given the complex, interstate nature of the electric system, there are numerous questions with regard to *how* states and sources should receive credit for renewable generation and *what* they should receive credit for. First, we recommend that EPA use the avoided MWh approach rather than the avoided CO_2 approach for computing the compliance formula. While the latter may in theory provide a more accurate picture of the environmental benefits of RE, it requires dispatch modeling for which the necessary data is not available, whereas the former is far simpler and more transparent, permits greater upfront planning, and allows for methodological consistency with existing programs. Second, the agency should grant RE credit to states that incentivized the development of the RE, regardless of where the RE is located and the electricity is consumed. This will help encourage RE development and will maintain consistency with most RPS programs.

Next, we urge EPA to establish methods to prevent double-counting with regard to RE generation that crosses state lines and to address some of the complexities associated with renewable energy credits ("RECs"), which are likely to be important compliance tools. While we believe that double-counting is not an inherent feature of the rule, the agency must remain vigilant against it, requiring states to comprehensively track and verify the amount and source of the RE they intend to use in their compliance demonstration. Finally, in terms of resources that should qualify as RE, we support distributed solar generation, utility-scale solar, and wind power. We also support the development of new small-scale hydropower for compliance purposes, although we agree that hydropower should not be included in the target-setting, since this would distort the RE goals in certain regions. Similarly, we oppose biomass for both goal-setting and compliance. This resource is associated with significant CO_2 emissions as well as other environmental impacts. Should EPA include biomass in its formula or permit it for compliance purposes, it must conduct a rigorous analysis of the true CO_2 emissions from these sources and solicit additional comments.

D. Block 4: Increased Use of Energy Efficiency

Energy efficiency ("EE") is the lowest-cost method of reducing CO_2 emissions and is generally the first resource to dispatch to the grid. EE measures have been in place for decades and have many benefits apart from carbon reduction: they ease pressure on the grid and help ensure reliability, they save consumers money on electricity bills (and operators on fuel costs), and they reduce criteria pollutant emissions as well as upstream impacts from fossil fuel extraction, processing, and transmission. EE is therefore a *sine qua non* of any national program to reduce CO_2 from the electric sector, and EPA has rightly included it as an element of BSER in Building Block 4.

The agency's "best practice" approach to Block 4 assumes that states can sustain annual incremental EE gains of 1.5 percent per year of retail electricity sales during the compliance period. Higher-performing states will begin at the 1.5 percent annual incremental rate beginning in 2020, while lower-performing states will begin ramping up their EE investment starting in 2017, hitting 1.5 percent no later than 2025. These goals are well-supported and achievable in a cost-effective manner in all fifty states. Eleven states already have enforceable programs requiring 1.5 percent or greater by 2020, and three states—Arizona, Maine, and Vermont—already achieved savings greater than 1.5 percent in 2012. Those states that have not thus far achieved significant savings through EE will have little difficulty achieving the 1.5 percent rate by the date expected under Block 4, since those are the states in which the lowest-hanging fruit still remains.

EPA's approach to Block 3 is a sensible and effective strategy for reducing CO_2 emissions, although research suggests that savings greater than 1.5 percent annually may be appropriate. We offer two modifications that will strengthen Block 3. First, EPA should remove the 1.5 percent ceiling for those states that already have enforceable EE requirements that exceed that figure for 2020 or earlier. The agency should not lower the bar below the commitments that states have already set for themselves. Second, for net-importing states, EPA calculates the number of "negawatt-hours" associated with Block 4 according to the percentage of electricity sales originating from in-state generators, rather than all retail sales. It does not, however, correspondingly *increase* the savings that are expected of net-*exporting* states, since states cannot control consumer behavior beyond their borders. Yet Building Block 4 merely specifies the EE savings that are available in each state, and it is both feasible and fair to expect states to reduce their own in-state generation in response to reduced electricity demand through EE, rather than shifting some responsibility for curtailing generation onto exporting states. Notably, this approach will not actually add any burden to importing states that meet their EE targets, since they will receive full credit for their negawatt-hours, rather than reduced credit under EPA's current proposal. Together, these modifications to Block 4 will produce significantly greater emission reductions than under the agency's current model.

With regard to Block 4 compliance, EPA has offered strong guidance in its CPP preamble and technical support documents, and we offer a number of additional suggestions. The agency should first issue comprehensive guidelines or requirements for evaluation, measurement, and verification ("EM&V") procedures, which states will use to ensure that their EE measures are, in fact, achieving CO_2 emission reductions. We also urge EPA to develop guidelines for determining the proper lifespan of an EE measure or program, and to assist states in developing REC-like mechanisms for EE credits, which have not yet gained widespread use. As noted above, we believe states should receive credit for 100 percent of the savings achieved through in-state EE measures, regardless of where the emission reductions occur. Finally, because we believe that EGU owners and operators should bear the full responsibility for emission reductions under the CPP, we urge EPA to give credit only to those EE measures that an EGU owner/ operator can play a role in implementing. While this would encompass the kinds of EE programs sponsored by utilities or private parties such as industrial entities, it would not include building codes or appliance standards. We support strong building codes and appliance standards, but we do not believe they are appropriate compliance mechanisms under the CPP.

IV. State Plan Considerations

A. Affected EGUs Must Be Legally Responsible for All Emission Reductions

In line with the Clean Air Act's requirements, EPA must ensure that state plans impose all of the responsibility for the required emission reductions on owners and operators of affected EGUs. State plan requirements must also be federally enforceable against affected sources, by EPA and through citizen suits. States that follow a rate-based protocol will need to include a mechanism that adjusts the emission rates of individual sources according to reductions achieved through EE, RE, and other measures apart from on-site HRIs. This mechanism could be a trading system for RECs and other emission reduction credits, or it could be a program through which the state administratively allocates emission reduction credits across the fleet of affected sources.

B. Rate-to-Mass Conversions

A key feature of the CPP is that states may choose either rate-based or mass-based compliance scenarios. It is critical that any mass-based target generate equivalent emission reductions to its corresponding rate target designated by EPA. We propose three guiding principles for any state converting a rate-based goal to a mass-based one. First, rate and mass are related to one another through a simple formula: mass equals rate times generation. Second, "generation" here refers to a state's regulated generation for each compliance period. By "regulated generation," we simply mean any electricity that could be added to a state's denominator when determining compliance with the rate (megawatt-hours from existing fossil and RE generation, and negawatt hours from EE measures). Any state wishing to include EE and RE in its rate-to-mass conversion will need to provide the same level of EM&V rigor that would otherwise be included for compliance in a rate-based scenario. Third, mass-based states will, at the outset, project their electric load for each compliance year, but must update those projections during the compliance period to reflect the true quantity of regulated electricity generated in that year. This annual "true-up" will ensure that states are neither penalized in their mass targets for having underestimated electric demand from regulated units nor given a windfall for having overestimated demand. It is also necessary to ensure that a state's retired units are not later included in the pool of regulated generation, artificially raising its mass cap. EPA did not address this necessary true-up in its technical support document discussing rate-to-mass conversions, and should reject any mass-based plan that does not include it.

C. Compliance and Enforcement Issues for State Plans

EPA must strengthen the CPP to ensure strict compliance with the rule's emission targets. First, the agency must require actionable corrective measures in every state plan, set appropriate minimum thresholds and standards for the adoption, activation, and implementation of these measures, and require states to report publicly the causes of any performance deficiency that triggers corrective action. Second, state plans must assess individual EGU compliance over a period of no more than one year, and states should be required to submit annual, public reports to EPA on the status of their emission reduction progress. Third, EPA should not permit sources to estimate emissions through fuel consumption calculations, but must require continued monitoring emissions systems at *all* EGUs. Affected EGUs should also be required to submit engineering analyses and reference method test results for any compliance measures they wish to use to meet enforceable emission limits. This is necessary to ensure that the selected measures are, in fact, effective. Lastly, EPA must strengthen record retention requirements and ensure that facilities maintain all records onsite.

With regard to state plan approval, EPA should clarify that it will issue a federal implementation plan for any state that lacks an approvable plan of its own within six months after the submission deadline. The agency should also make approval of state plan contingent on the state's adequate demonstration that it possesses not only the legal authority to enact and enforce the plan, but the resources necessary to implement it as well. EPA must amend its proposed regulations to ensure that the state plans include emissions standards that are enforceable by citizens. Finally, EPA should abandon the option of conditional plan approval. If a plan is not adequate at the time a state submits it, the agency should simply reject it and require the state to submit a proposal without deficiencies if it wishes to avoid a federal implementation plan.

V. Environmental Justice Considerations

Minority and low-income communities bear disproportionate health and socio-economic risks from climate change. In the United States, these communities often live near dirty power plants and other large industrial facilities, and also in areas vulnerable to climate change impacts such as sea-level rise. As climate change worsens, environmental justice communities will spend higher proportions of their income as a result of rising food prices or increased water scarcity. To ensure that these communities receive the benefits of the CPP, EPA must address not only overall carbon emissions reductions, but also co-pollutant implications and local communities' growth. EPA must ensure that, first, these communities do not experience increased levels of pollution as a result of the implementation of measures that increase the utilization of certain affected sources. Second, these communities must benefit from the positive environmental and health effects that will result from the decreased utilization of dirty power plants and the development of renewable energy generation.

In order to properly integrate environmental justice concerns into the CPP, EPA must prepare an environmental justice analysis of the rule, as required under Executive Order 12898. To this end, EPA should require states to conduct an environmental justice analysis as a component of state plans. This analysis will help to ensure that the different compliance measures selected by states under their plans do not cause adverse impacts, and actually benefit minority and low income populations. EPA must also ensure that state agencies that receive federal funding under Title VI of the Civil Rights Act under state plans comply with their obligation not to discriminate on the basis of race, color, or national origin. In the final rule, the agency also needs to make clear that emission standards that would allow uncontrolled or poorly controlled emissions from individual sources are not permissible as Section 111(d) emission guidelines for pollutants with localized health and environmental impacts. Finally, to the extent that the CPP allows states to comply through trading of RECs or CO_2 allowances, EPA must establish guidelines for states to effectively integrate environmental justice concerns into the design of these programs in a manner that restricts trading practices that could exacerbate hotspots and that provides for investments in clean energy and the revitalization of these communities.

VI. Economic Justice Considerations

Investments in energy efficiency and renewable energy to comply with the CPP will produce major additional benefits throughout the U.S. economy, making the clean energy economy a major new engine of U.S. job creation. Renewable energy has become cost competitive with fossil fuels, including coal, oil, and natural gas, as well as with nuclear power. In addition to reducing carbon emissions, the ancillary benefits of the CPP—developing renewable energy, energy efficiency and a modernized, smart power grid—will, when combined with high road employment practices, create millions of good jobs for people who desperately need them, especially people from economically and environmentally distressed communities. States must take the driver’s seat in crafting compliance plans that expand renewable energy and energy efficiency, while also prioritizing the creation of good, clean energy jobs to promote state and local economic development and improve community and workers’ livelihoods.

There are clear environmental and public health benefits of replacing fossil fuels with energy efficiency and renewable energy. Jobs will be created with the CPP, but we cannot ignore the fact that some jobs will be lost and specific communities will be affected as we make the transition away from fossil fuels. The CPP state implementation process provides tremendous opportunities for state and federal policymakers to take concrete policy steps, through workers’ transition policies and funding mechanisms, to address the fears of low income and working class communities and union representatives in carbon-intensive sectors that a market-driven clean energy transition means economic insecurity for them. The government has a key role in helping to drive a fair and just transition to a clean energy economy that will maximize investments in economic development, provide security to affected workers, and protect the tax base by creating lasting, good jobs in affected communities.

VII. Carbon Tax

EPA should amend the proposed regulations to clarify that states may use a carbon tax as a compliance mechanism. Numerous studies have demonstrated that a carbon tax is an effective means of reducing greenhouse gas emissions. A carbon tax is economically efficient and relatively easy to administer. Moreover, it provides revenue that can be used to offset electricity rate increases for low income households, to implement EE programs in low income communities, and to finance co-pollutant reductions in environmental justice communities.

VIII. Impacts on Upstream Emissions

While the CPP will undoubtedly achieve significant reductions in CO_2 emissions at the point of combustion, EPA must accurately account for any upstream impacts on greenhouse gas emissions that may result from the rule. Of particular concern is methane, a potent heat-trapping pollutant that far exceeds the global warming potential of CO_2 on both 20- and 100-year bases. During all phases of natural gas extraction (production, processing, transmission, storage, and distribution), methane is emitted by equipment leaks or intentional venting. These emissions partially—and, if high enough, entirely—offset the climate benefits of combusting natural gas instead of coal to generate electricity. Methane is also released during coal mining, when reservoirs previously trapped in ore seams are exposed to the atmosphere.

EPA predicts in its regulatory impact analysis ("RIA"), that while the CPP will increase gas production in the short term (leveling out over the long-term), it will reduce coal-mining enough such that methane emissions will decline from a business-as-usual scenario. We offer three important caveats to that prediction. First, given the magnitude of methane emissions associated with gas production (as well as the sizable quantities of CO_2 resulting from gas combustion), EPA must incentivize the use of EE and RE for plan compliance over gas-fired generation. Second, EPA must provide for a rigorous and proper accounting of the actual methane emissions associated with fossil fuel extraction. We are concerned that the agency's Greenhouse Gas Inventory and other "bottom-up" analyses significantly underestimate the true quantity of methane in the atmosphere resulting from natural gas extraction. The agency must address the most recent research, including "top-down" atmospheric studies, and adjust its estimates accordingly. Third, EPA must act swiftly to directly regulate methane emissions from the oil and gas industry. Emissions from this industry *will* increase under the CPP (even if EPA is correct that overall emissions will decrease), and there is ample support for cost-effective regulations that will, in many cases, generate additional revenue for industry through conserved gas.

Furthermore, EPA assumes in its RIA that decreased coal generation will result in a proportionate reduction in coal mining. The agency must address the impacts that will occur if increased coal exports offset (either partially or wholly) the reductions that would otherwise occur in coal mining under the CPP.

IX. Reliability

Several grid operators and affiliated groups have raised concerns over the number of projected retirements of covered units the CPP may necessitate, and how such retirements would affect the "reliability" of the power grid. In particular, they have raised concerns that retirement of existing units will threaten the grid's overall resource adequacy, its voltage and frequency stability, and its resilience against major grid disturbances.

The fact that these concerns were raised is not surprising: each time EPA undertakes rulemakings affecting the electric generating sector, naysayers cry that the lights will go out. The concerns are, however, both exaggerated and unfounded. Most of these same groups have been considering the grid impacts of retiring inefficient fossil fuel-burning power plants for years, and have responded by redesigning markets and transmission systems to accommodate renewable energy and other nontraditional power resources. As a result, we already know how to integrate renewable generation resources without disrupting the grid, by ensuring that the replacement resources also replace any essential reliability services that may be required (indeed, most new renewable facilities are already required to have this capability). Meanwhile, electricity storage systems and demand response programs, both of which have seen increasing use over the last several years, are well equipped to fill in any shortfalls that may arise.

In particular, we oppose two specific policy recommendations made by utilities and operators: first, to delay implementation of the CPP, which would further delay our necessary transition to new and cleaner power sources; and second, to include a "reliability safety valve," which would in effect reward the utilities and affected EGUs who drag their feet by allowing them to continue emitting large amounts of greenhouse gases. These policy recommendations mirror similar recommendations made each time EPA suggests a new set of rules, but they are particularly unnecessary here because the CPP is if anything *more* responsive to potential reliability concerns than several other recent EPA rules. Unlike national standards that are imposed inflexibly on individual facilities, the CPP relies on a cooperative federalism model that allows states to design their plans to minimize disruptive impacts on the grid. We are therefore confident that states working in conjunction with regional grid operators will be able to ensure a smooth transition to a cleaner and more efficient power grid over the next five to fifteen years.

Finally, we join with these grid operators and other commenters in calling on EPA to encourage advanced planning for anticipated supply shifts, and especially to facilitate cooperation between states and regional and local grid operators when implementing the CPP. Although the grid restructuring necessary to support a shifting resource load is definitely manageable, it will require advanced preparation, and EPA should support that work in whatever way it can.

X. Other Issues

A. The Symmetry Principle

EPA has expressed that it may allow states to use non-BSER measures for compliance purposes. If it does so, EPA must adhere to what we refer to as the "symmetry principle": the stringency of the state goals must reflect the full set of measures that can be used to comply. Thus states should not be allowed to use non-building block measures such as new NGCC units or new unplanned nuclear capacity for compliance.

B. The Compliance Timeline and Revised Guidelines

EPA's current CPP proposal extends the compliance period until 2030, and the agency has also solicited comment on an alternative compliance period ending in 2025, with interim goals applying between 2020 and 2024. We urge EPA to adopt the shorter time frame, but we believe that the state goals proposed for the 2025 option are far too weak. Indeed, our analysis of the building blocks demonstrates that the state goals should be much more stringent than those included in the 2030 option. EPA should require full compliance by 2025 because the vast majority of emission reductions can be achieved early on in the compliance period. In addition, we urge EPA to adopt two additional features. First, EPA should advance the compliance schedule to begin as early as January 2018 rather than 2020 to capitalize on the changing nature of electricity markets and the rapid development of renewable resources. We believe that a three-year window is sufficient time for states to begin working toward compliance. Second, the agency should engage in a continuous internal review of the rule during the compliance period and should commit to issuing a revised set of emission guidelines that would take effect in 2026. We also oppose any effort by EPA to relax the stringency of the glide path or phase in emission reductions under Building Blocks 1 and 2. States are free to apportion their emission reductions across the compliance period however they choose so long as the interim and final goals are met. This measure of flexibility provides a sufficient buffer against stranded assets and other technical challenges toward achieving compliance, and no additional relaxation of the glide-path is necessary.

C. New Source Review

Measures that affected sources implement to comply with the CPP are unlikely to trigger New Source Review ("NSR") permitting requirements. To ensure that sources will not generate enough emissions to trigger NSR, states can include in their plans rigorous source-specific limits on emissions or operations. EPA may not legally permit states to exempt sources from NSR for actions implementing the CPP. Such sources should be subject to emissions limits if they modify and increase their emissions and exempting them would put neighboring communities at risk. Moreover, exempting sources would encourage "life extension" programs at fossil fuel-fired EGUs that would undermine the goals of both the Clean Air Act, to end the grandfathered status of aging plants, and the Climate Action Plan, to transition the U.S. electric supply sector to lower carbon intensity technologies.

I. Introduction

As EPA has properly concluded in its 2009 Endangerment Finding, the scientific record demonstrating that "elevated concentrations of greenhouse gases in the atmosphere may reasonably be anticipated to endanger the public health and welfare of current and future U.S. generations is robust, voluminous, and compelling."[1] Existing electric generating units ("EGUs") are the single largest source of domestic greenhouse gas ("GHG") emissions. Accordingly, as we discuss at length below, EPA must control greenhouse gas pollution from this source category under section 111 of the Clean Air Act ("CAA" or the "Act"), 42 U.S.C. § 7411. Significantly reducing these emissions from existing domestic power plants is necessary to mitigate the serious harms associated with climate change in the United States.

In addition, fossil fuel-fired EGUs are significant sources of smog- and soot-forming pollutants, including sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), and fine particulate matter ("$PM_{2.5}$"), as well as hazardous air pollutants such as mercury ("Hg") and hydrochloric acid ("HCl"). In this introductory section, we briefly describe some of the harms associated with both greenhouse gas emissions and traditional pollutants, and show why the emissions profile of the EGU sector demands expeditious regulation under section 111 to mitigate the impact of climate change and protect the public health and welfare from air pollution.

A. Emissions of CO_2 and Traditional Air Pollutants from Fossil Fuel-Fired EGUs Threaten the Public Health and Welfare.

1. Harms Associated with Climate Change and Ocean Acidification

As discussed in the Endangerment Finding and the Clean Power Plan's Regulatory Impact Analysis ("RIA"),[2] climate change poses manifold threats to the public health and

[1] 75 Fed. Reg. 49,556, 49,557 (Aug. 13, 2010) (Endangerment Reconsideration Denial); *see also* 74 Fed. Reg. 66,496, 66,523 (Dec. 15, 2009) (Endangerment Finding)*; Coalition for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 122—28 (D.C. Cir. 2012) (upholding Endangerment Finding in its entirety).

[2] EPA, *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* ("RIA"), EPA -542/R-14-002 (June 2014), *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf. Several of the assessment reports cited in the Endangerment Finding and RIA (or updated versions of those reports) are attached and incorporated by reference. These include the IPCC's *Climate Change 2014: Synthesis Report* (2014), *available at http://www.ipcc.ch/pdf/assessment-report/ar5/syr/SYR_AR5_LONGERREPORT.pdf*, and *Climate Change 2013: The Physical Science Basis-Summary for Policymakers* (2013), *available at* http://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_SPM_FINAL.pdf, *full report available at* http://www.climatechange2013.org/); the NRC's *Advancing the Science of Climate Change* (2010), *available at* http://dge.stanford.edu/labs/caldeiralab/Caldeira_research/pdf/ACC_Science_2010.pdf, and *Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia* (2011), *available at http://www.climatechange-foodsecurity.org/uploads/NRC_climate_impacts.pdf*; and the USGCRP's *Climate Change Impacts in the United States (Third National Climate Assessment*

welfare. A changing climate will increase the incidence and severity of heat waves, which lead to temperature-related deaths and enhanced ozone (or smog) formation, a major public health problem in its own right.[3] Climate change will also produce heavier precipitation events, stronger tropical cyclones, and associated flooding, spreading toxins and diseases and causing severe infrastructure damage, social upheaval, and widespread injury and death.[4] Pathogens and pests are expected to disseminate more widely due to changes in those species' survival, persistence, habitat range, and transmission under changing climate conditions.[5]

In addition, sea level rise is well documented and is very likely to accelerate over the coming decades.[6] Rising seas and extreme weather events will threaten our coastal homes, cities, and infrastructure, forcing expensive efforts to protect or relocate critical resource and displacing millions of people.[7] Further inland, early spring melts will increase flood risks early in the melt season, while shrinking snowpack will cause water shortages throughout much of the west.[8] Droughts, especially in the western and southern United States, are expected to occur more frequently and (along with changing atmospheric chemistry) will likely cause crop damage and failure and corresponding food shortages. Forested lands will see more severe fires, pest outbreaks, and higher tree mortality, which will likely disrupt timber production.[9]

Climate change also will threaten natural environments and biodiversity, which offer humans a wide range of benefits and services, including fresh water, fertile soil, fisheries, climate regulation, and aesthetic, cultural, and recreational benefits.[10] The combination of global temperature increases and other environmental stressors will tax many plant and animal species to the point of extinction. Research indicates that climate change and other anthropogenic factors are causing the sixth mass extinction of global biodiversity in the last 600 million years of life on Earth, with current extinction rates 100 to 1,000 times greater than

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Report)- Overview (2014), *available at* http://nca2014.globalchange.gov/highlights/overview/overview, *full report available at* http://nca2014.globalchange.gov/downloads). *See also* RIA at 4-2—4-3 (listing publications).

[3] RIA at 4-2—4-8; USGCRP, NCA overview, *supra* n. 2, at 11; Pfister *et al.*, *Projections of Future Summertime Ozone Over the U.S.*, J. of Geophysical Research: Atmospheres (May 5, 2014) (higher temperatures increase smog formation in already polluted areas).

[4] RIA at 4-6.

[5] *Id.*; USGCRP, NCA overview, *supra* n. 2, at 11.

[6] RIA at 1-2, 4-3—4-6; USGCRP, NCA overview, *supra* n. 2, at 7-11; IPCC, *Climate Change 2014: Synthesis Report*, *supra* n. 2, at SYR-7—8

[7] *Id.*

[8] *Id.* at 1-2, 4-16, 4-13; USGCRP, NCA overview, *supra* n. 2, at 10-11.

[9] RIA at 4-4; USGCRP, NCA overview, *supra* n. 2, at 11; IPCC, *Climate Change 2007: Impacts, Adaptation, and Vulnerability* (2007), *available at* http://www.ipcc.ch/publications_and_data/publications_ipcc_fourth_assessment_report_wg2_report_impacts_adaptation_and_vulnerability.htm, at Ch. 5: Ecosystems, Their Properties, Goods and Services.

[10] USGCRP, NCA overview, *supra* n. 2, at 11-12.

historical rates.[11] In 2007, the IPCC concluded that by the mid-21st century, 15 to 37 percent of plant and animal species worldwide would be committed to extinction if temperatures increase 1.6 to 1.8 degrees Celsius above late 20th century levels.[12] Even species that do not go extinct will have to contend with unprecedented ecological conditions, and many will be forced to migrate to new and unfamiliar latitudes to survive.[13]

Independent of climate change, some of the carbon dioxide ("CO_2") emitted via fossil fuel combustion is subsequently absorbed by the world's oceans. Because carbonic acid forms when carbon dioxide dissolves in water, rising CO_2 emissions are causing the seas to become more acidic. The NRC has reported that ocean acidity has increased approximately 30 percent since pre-industrial times, and could intensify by three to four times this amount by the end of the century if carbon emissions remain uncurbed.[14] Increased acidification poses a significant threat to the ocean's critical food webs. Along with increasing surface stratification because of warmer surface water, ocean acidification may result in a "widespread decline in marine primary production," doing great damage to the base of the oceanic food chain with potentially devastating effects on the food supply for many regions around the globe.[15]

Greenhouse gas emissions and atmospheric carbon concentrations have continued to rise in the years since EPA made its Endangerment Finding. For instance, global greenhouse gas emissions are now rising faster than the IPCC's highest emissions scenario from 2007, as illustrated in the figure below, compiled by the European Environment Agency.

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[11] Pimm *et al.*, *The Future of Biodiversity*, 269 Science 347, 347 (1995); Dirzo and Raven, *Global State of Biodiversity and Loss*, 28 Annual Review of Environment and Resources 137, 137 (2003); Barnosky *et al.*, *Has the Earth's sixth mass extinction already arrived?*, 471 Nature 51 (2011).

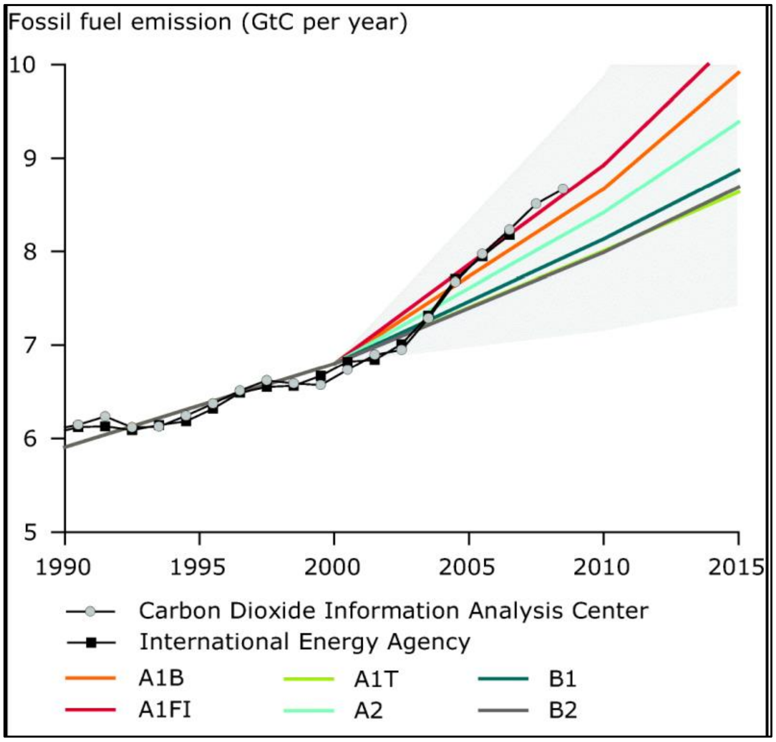
[12] IPCC, *supra* n. 9, at 243; *see also* Clavel *et al.*, *Worldwide decline of specialist species: toward a global functional homogenization?,* 9 Frontiers in Ecology and the Environment 222 (2011).

[13] Chen *et al.*, *Rapid Range Shifts of Species Associated with High Levels of Climate Warming*, 333 Science 1024 (2011).

[14] NRC, *Advancing the Science of Climate Change*, *supra* n. 2, at 55; *see also id.* at 56, 59-60; NRC, *Climate Stabilization Targets, supra* n. 2,at 209-210; Hönsich *et al.*, *The Geological Record of Ocean Acidification*, 335 Science 1058, 1058 (2012).

[15] Gao *et al.*, *Rising CO_2 and Increased Light Exposure Synergistically Reduce Marine Primary Productivity*, 2 Nature Climate Change 519, 519 (2012).

Fig. 1- IPCC Emission Scenarios[16]



This graph compares six IPCC emissions scenarios (labeled A1B to B2) with actual atmospheric carbon measurements from two sources. In the last decade, global emissions have rapidly increased to match, or even slightly outpace, the most aggressive IPCC scenario, A1F1, which assumes a "world of very rapid economic growth" with "fossil-intensive" energy systems.[17]

Indeed, several reports and assessments attest that threat of climate change is even more pressing than anticipated just a few years ago. For instance, a recent IPCC report notes that "satellite-measured sea levels continue to rise at a rate closer to that of the upper range of [earlier] projections" and that "the contribution to sea level due to [ice] mass loss from Greenland and Antarctica is accelerating."[18] The IPCC's AR5 and the USGCRP's Third National Climate Assessment reflect similar conclusions with regard to sea level rise based on superior modeling and data inputs. [19] As the Climate Assessment authors note, "[c]ontinued warming and an increased understanding of the U.S. temperature record, as well as multiple other sources of evidence, have strengthened our confidence in the conclusions that the warming

[16] "Observed global fossil fuel CO_2 emissions compared with six scenarios from IPCC," *available at* http://www.eea.europa.eu/data-and-maps/figures/observed-global-fossil-fuel-co2/ccs102_fig2-3.eps.
[17] *See* IPCC, *Climate Change 2007: Synthesis Report* (2007) *available at* http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr.pdf, at 44.
[18] IPCC, *Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation* (2012), *available at http://www.ipcc-wg2.gov/SREX/images/uploads/SREX-All_FINAL.pdf*, at 178-79.
[19] IPCC, full scientific report for AR5, *supra* n. 2, at 1140; USGCRP, full NCA report, *supra* n. 2, at 21.

trend is clear and primarily the result of human activities."[20] And in May 2013, a federal working group revised its range of monetary values representing the social cost of carbon from $7, $26, $42, and $81 per ton of CO_2 emitted in 2020 to $12, $43, $65, and $129, respectively, a reflection of the continuous upward assessment of the harms posed by climate change.[21]

2. Climate Stabilization Requires Immediate, Deep Reductions in Emissions from the EGU Sector.

CO_2 emissions from power plants remain the single largest source of U.S. greenhouse gas pollution and are a significant component of global emissions. Without emissions controls for this sector, it will be impossible to stabilize atmospheric greenhouse gas emissions at a safe level. EPA's Inventory of Greenhouse Gas Emissions and Sinks reports that electricity generation was responsible for 2,022 million metric tons of CO_2 in 2012, 37.5 percent of annual domestic emissions.[22] A full three-quarters of U.S. electricity sector emissions come from coal-fired EGUs, with most of the remainder coming from natural gas-fired units. [23] Given the dominance coal combustion in the U.S. electricity sector, EPA must act rein in emissions from coal-fired plants and encourage their replacement with renewable energy and demand reductions from efficiency investments. Immediate action is critical if we are to transition to an electricity sector that minimizes our impact on global climate change.

Domestic action to combat climate change will have benefits that extend far beyond our borders. As of 2012, the United States was responsible for approximately 13.4 percent of global anthropogenic GHG emissions and 15 percent of CO_2 emissions).[24] The U.S. power sector alone contributed approximately 4.5 percent of worldwide GHG emissions and over 6 percent of all CO_2 emissions.[25] Steep cuts from large sources like the U.S. power sector are therefore critical to prevent truly disastrous climate impacts. As the NRC's 2011 report on climate stabilization

[20] USGCRP, full NCA report, *supra* n. 2, at 21.

[21] IWG, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (Nov. 2013), *available at* *http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf*, at 2. While we believe that the IWG's updated figures fundamentally underestimate the true cost of carbon emissions, they nonetheless reflect the same trend as seen in the scientific literature: as research on climate change continues to amass, our awareness and assessment of the many threats it poses to our world grows as well.

[22] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990—2012*, EPA 430-R-14-003 (Apr. 15, 2014), *available at* *http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Main-Text.pdf*, Table 2-1.

[23] *Id.* at Table 3-5.

[24] European Union Emission Database for Global Atmospheric Research (EDGAR), *GHG (CO_2, CH4, N2O, F-gases) emission time series 1990-2010 per region/country*, *available at* http://edgar.jrc.ec.europa.eu/overview.php?v=GHGts1990-2010, and *CO2 time series 1990-2012 per region/country*, *available at* http://edgar.jrc.ec.europa.eu/overview.php?v=CO2ts1990-2012.

[25] According to the EDGAR database, global GHG emissions in 2010 were 50,101 million metric tons CO_2e.

emphasizes, worldwide emissions reductions on the order of 80 percent by the century's end are necessary to prevent temperatures from exceeding 2 degrees Celsius above pre-industrial levels.[26] The IPCC has determined with "high confidence" that "[d]elaying mitigation efforts beyond those in place today through 2030 is estimated to substantially increase the difficulty of the transition to low longer-term emissions levels and narrow the range of options consistent with maintaining temperature change below 2°C relative to pre-industrial levels."[27] Without swift and significant emissions controls for the U.S. power sector, the odds of preventing the most extreme effects of climate change are virtually nil.

3. Reducing Climate Pollution Will Also Reduce Conventional Pollution from Fossil Fuel-Fired Power Plants

Combusting fossil fuels—particularly coal—not only drives global climate change, but also emits numerous air pollutants into the atmosphere that have serious ramifications for public health and wellbeing. Coal plants are the leading source of SO_2 emissions in the United States, with an average unit emitting between 7,000 (if controlled) and 14,000 (if uncontrolled) tons per year.[28] Once emitted into the atmosphere, SO_2 forms $PM_{2.5}$, or soot, which can cause asthma attacks, chronic obstructive pulmonary disease, stunted lung development, lung cancer, stroke, heart attack, and congestive heart failure.[29] Fossil plants also emit $PM_{2.5}$ and $PM_{2.5}$ precursors directly into the atmosphere, and while control technologies exist to limit these emissions, substantial emissions still result from the operation of well-controlled units.

Coal combustion is also a major source of NOx[30], with a typical coal-fired plant emitting between 3,000 (if controlled) and 10,000 (if uncontrolled) tons per year.[31] These compounds interact with volatile organic compounds (VOCs) in the presence of sunlight to form ground level ozone, a highly toxic and reactive pollutant. At times ozone can also interact with other atmospheric matter to form a smoky fog of deadly pollutants known as smog.[32] SO_2 and NO_x will travel great distances and react in the atmosphere to form very fine nitrate and sulfate particles. As components of the overall $PM_{2.5}$ mix, these emissions cause significant pulmonary and cardiovascular ailments and lead to increased rates of missed work, hospitalization, and premature death.[33] Furthermore, coal-fired EGUs are responsible for more than half of the human-made emissions of mercury, a dangerous neurotoxin that can lead to developmental

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[26] NRC, *Climate Stabilization Targets*, *supra* n. 2, at 10.

[27] IPCC, *Climate Change 2014: Mitigation of Climate Change- Summary for Policymakers* (2014), *available at http://report.mitigation2014.org/spm/ipcc_wg3_ar5_summary-for-policymakers_approved.pdf*, at 13.

[28] Union of Concerned Scientists ("UCS"), *Environmental impacts of coal power: air pollution,* http://www.ucsusa.org/clean_energy/coalvswind/c02c.html (last visited Nov. 12, 2014).

[29] *Id.*; Lockwood, et al., Physicians for Social Responsibility, *Coal's Assault on Human Health* (Nov. 2009), *available at http://www.psr.org/assets/pdfs/psr-coal-fullreport.pdf*, at vii-viii, x, and generally.

[30] NO_x refers to a mix of different oxides of nitrogen, primarily NO_2 and NO_3.

[31] UCS, *supra* n. 28.

[32] Lockwood, *supra* n. 29, at 10.

[33] *Id.* at x, 10-11, 17, 24; *see also* RIA at 4-14—4-22.

delays and permanent cognitive impairment in fetuses and children.[34] Finally, coal-fired plants that are not properly controlled can emit significant quantities of other hazardous air pollutants, including toxic heavy metals such as lead and cadmium, carbon monoxide, volatile organic compounds, and arsenic.[35]

All told, pollution from coal plants causes tens of thousands of premature deaths, emergency room visits, and heart attacks each year, and hundreds of thousands of asthma attacks.[36] This amounts to over $100 billion in annual health care costs.[37] EPA has issued regulations to reduce these emissions, but until we transition to genuinely clean energy, the lives and health of countless Americans remain at risk.

Natural gas-fired power plants also emit significant amounts of conventional pollutants, especially NOx. Even with modern pollution controls, natural gas-fired power plants contribute to reduced air quality and harm public health. Older natural gas-fired plants with lower efficiencies and less effective pollution controls result in more significant environmental and health impacts. These harmful impacts are particularly acute for local communities that live in close proximity to power plants.

Any effort by EPA to reduce greenhouse gas emissions from power plants will necessarily reduce other harmful pollutants from fossil generators as well. The agency must take action to secure the health and wellbeing of the American public.

B. A Stringent Clean Power Plan Is Essential to Meet U.S. International Commitments.

The Clean Power Plan has important international implications. It is integral to achieving President Obama's international commitment to reduce U.S. carbon emissions. President Obama's recent pledge to achieve more ambitious GHG emission reductions by 2025 will require a stronger Clean Power Plan. Along with other federal GHG regulations, it will play a vital role in achieving the new emissions reduction target. A strong plan will bolster U.S. leadership as a leader on climate change and help strengthen its position in international climate negotiations.

In its 2014 synthesis report, the IPCC warns that without immediate action to curb GHG emissions, climate change will have dire and irreversible impacts worldwide.[38] Climate change is no longer a distant threat, but is being felt around the globe, and immediate and significant carbon emission reductions are needed to curtail warming of the planet. "Science has spoken.

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[34] Lockwood, *supra* n. 29, at 11, 30-32; UCS, *supra* n. 28.
[35] UCS, *supra* n. 28.
[36] Sierra Club, *Fact Sheet: The Health Costs of Coal—It Isn't Just Dirty, It's Making Us Sick*, *available at* *http://vault.sierraclub.org/designarchive/factsheets/beyondcoal/106%20Coal%20Health/high106_coalhealth_factsht.pdf*.
[37] *Id.*
[38] IPCC, *2014 Synthesis Report*, *supra* n. 2.

There is no ambiguity in the message," said U.N. secretary general, Ban Ki-moon at the report's launch. "Leaders must act. Time is not on our side."[39]

Despite mounting evidence of the dire consequences of inaction, U.S. action on climate change has been stymied on the congressional level for years, with failed cap-and-trade legislation in 2009 and continued resistance to all forms of action from lawmakers beholden to fossil fuel interests. This has left the U.S. in a precarious position in international climate negotiations. It has created the impression among other countries that the U.S. is not serious about climate change and has provided an excuse for them not to take ambitious action to reduce emissions themselves.

President Obama has responded to the legislative gridlock by taking steps to address climate change through executive action. In Copenhagen in 2009, he pledged that the U.S. would reduce its GHG emissions in the range of 17 percent below 2005 levels by 2020.[40] To achieve this goal, the Obama Administration has taken several important regulatory actions to reduce carbon emissions from different sources, including adopting new fuel economy standards for vehicles, proposing carbon pollution standards for new power plants and modified and reconstructed power plants, and proposing the Clean Power Plan for existing power plants.[41]

President Obama has also taken several steps to limit the use of hydrofluorocarbons ("HFCs"), which are potent greenhouse gases. In 2013, the U.S. and China agreed to work together to phase down the consumption and production of HFCs, and G-20 leaders followed by expressing support for the same. In early 2014, the U.S., Canada, and Mexico, submitted a

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[39] Carrington, D., The Guardian, *IPCC: rapid carbon emission cuts vital to stop severe impact of climate change* (Nov. 2, 2014), *available at* http://www.theguardian.com/environment/2014/nov/02/rapid-carbon-emission-cuts-severe-impact-climate-change-ipcc-report.

[40] Appendix I to the *Copenhagen Accord, U.S. Quantified economy-wide emissions targets for 2020* (Jan. 28, 2010), *available at* http://unfccc.int/files/meetings/cop_15/copenhagen_accord/application/pdf/unitedstatescphaccord_app.1.pdf.

[41] Kahn, D., *California: Schwarzenegger, Brown rally climate activists and policymakers to influence Paris talks*, Climatewire, (Sept. 8, 2014), *available at* http://www.eenews.net/climatewire/stories/1060005373/feed. *See generally 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards*, Final Rule, 77 Fed. Reg. 62,624 (Oct. 15, 2012); *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Proposed Rule*, 79 Fed. Reg. 1430 (Jan. 8, 2014); *Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units, Proposed Rule*, 79 Fed. Reg. 34,959 (June 18, 2014); and *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Proposed Rule*, 79 Fed. Reg. 34,830 (June 18, 2014).

North American proposal to amend the Montreal Protocol to impose limits on HFCs.[42] The Montreal Protocol has been hugely successful in almost eliminating the use of chlorofluorocarbons ("CFCs") and other man-made ozone-depleting chemicals that are also potent GHGs, but these chemicals have been replaced with HFCs, many of which are even more powerful climate forcers. Alternatives to HFCs that are not climate warming agents are now available, and EPA recently proposed two new rules under its Significant New Alternatives Policy ("SNAP") program to phase out certain HFCs and promote safer alternatives.[43] Additionally, in September 2014, President Obama announced new private sector commitments and executive actions to reduce emissions of HFCs.[44] U.S. GHG emissions are currently nine to ten percent below 2005 levels, and the U.S. is making significant progress towards meeting its Copenhagen commitment.

In November, President Obama and President Xi Jinping of China reached a groundbreaking agreement to limit greenhouse gas emissions, with China committing for the first time to cap carbon emissions and the U.S. pledging deeper emissions reductions through 2025. In the agreement, President Xi Jinping pledged to cap China's rapidly growing carbon emissions by 2030, or earlier if possible, and to increase the share of China's energy mix derived from non-fossil fuel sources to 20 percent of the country's energy mix. This will require China to deploy 800-1,000 gigawatts of non-fossil fuel-fired power, such as wind and solar, by 2030—more than the generation capacity of all the coal-fired power plants that currently exist in China today and close to the total current electricity generation capacity in the U.S.[45] President Obama announced a target to cut U.S. carbon emissions 26 to 28 percent below 2005 levels by 2025, which represents significantly steeper reductions than the 2020 target the U.S. committed to in the Copenhagen Accord.[46] The U.S.-China agreement has been well-received around the globe. European Union leaders indicated that the new commitments by China and the U.S. will provide an important boost to the climate negotiations in Paris in December

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[42] U.S. EPA*, Ozone Layer Protection, Recent International Developments Under the Montreal Protocol, 2014 North American Amendment Proposal to Address HFCs under the Montreal Protocol*, http://www.epa.gov/ozone/intpol/mpagreement.html (last visited Nov. 21, 2014).

[43] *Protection of Stratospheric Ozone: Change of Listing Status for Certain Substitutes Under the Significant New Alternatives Policy Program*, Proposed Rule, 79 Fed. Reg. 46126 (Aug. 6, 2014); *Protection of Stratospheric Ozone: Listing of Substitutes for Refrigeration and Air Conditioning and Revision of the Venting Prohibition for Certain Refrigerant Substitutes*, Proposed Rule, 79 Fed. Reg. 38,811 (July 9, 2014).

[44] The White House*, Fact Sheet: Obama Administration Partners with Private Sector on New Commitments to Slash Emissions of Potent Greenhouse Gases and Catalyze Global HFC Phase Down*, (Sept. 16, 2014), *available at* http://www.whitehouse.gov/the-press-office/2014/09/16/fact-sheet-obama-administration-partners-private-sector-new-commitments-.

[45] The White House, *Fact Sheet: U.S.-China Joint Announcement on Climate Change and Clean Energy Cooperation*, (Nov. 11, 2014), *available at* http://www.whitehouse.gov/the-press-office/2014/11/11/fact-sheet-us-china-joint-announcement-climate-change-and-clean-energy-c.

[46] *Id.;* Lederman, J., *U.S., China Unveil Ambitious Climate Change Goals,* U.S. News & World Report (Nov. 11, 2014), *available at* http://www.usnews.com/news/articles/2014/11/11/china-and-us-unveil-ambitious-climate-change-goals.

2015,[47] where nations will negotiate an international agreement on greenhouse gas emission reduction targets that will come into effect after 2020.[48] The European Council has already committed to a binding target for the EU of at least a 40 percent reduction in greenhouse gas emissions by 2030 compared to 1990 levels.[49] In October 2014, the Council called on all countries in the EU to develop ambitious greenhouse gas emissions reduction targets and policies well in advance of the Paris Conference.[50] With the U.S., China, and Europe - the world's top three emitters of greenhouse gases - leading the way, other countries will be more likely to follow suit. Commitments from the U.S., China, and the EU give other nations an incentive to set their own reduction targets in preparation for international climate negotiations in December 2015. The U.S.-China agreement also positions the U.S. well for this year's Conference of the Parties in Lima, Peru, where negotiators will prepare the text of the climate agreement that will be finalized in Paris.

President Obama has also pledged $3 billion to the Green Climate Fund to help the most vulnerable nations reduce their emissions and adapt to climate change. Several other countries have also pledged significant funds, with the total reaching $9.3 billion at a recent conference in Berlin (closing in on a $10 billion minimum target for 2014). The fund is designed to help those countries least to blame for climate change that are being disproportionately impacted by its consequences, and will be dispersed over four years starting in 2015. This action represents a positive step towards a meaningful international climate agreement, and will help diffuse tensions between developed and developing nations that have complicated negotiations in the past.[51]

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[47] Nakamura & Mufson, *China, U.S. agree to limit greenhouse gases,* Washington Post (Nov. 12, 2014), *available at http://www.washingtonpost.com/business/economy/china-us-agree-to-limit-greenhouse-gases/2014/11/11/9c768504-69e6-11e4-9fb4-a622dae742a2_story.html.*

[48] Langley & Roberts, *The International Implications of the New EPA Clean Power Plan Proposed Rule*, Brookings, (June 4, 2014), *available at* http://www.brookings.edu/blogs/planetpolicy/posts/2014/06/04-implications-epa-clean-power-plan-langley-roberts.

[49] 1990 U.S. greenhouse gas emissions levels are considerably lower than 2005 U.S. levels--6,183 compared to 7,195 million metric tons of CO_2e. *See* EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011,* EPA 430-R-13-001 (Apr. 12, 2013), *available at* http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf, at Figure ES-1.

[50] European Council, *Remarks by President Herman Van Rompuy following the first session of the European Council* (Oct. 23, 2014); European Council, *Conclusions on 2030 Climate and Energy Policy Framework* (Oct. 23 and 24, 2014).

[51] Goldenberg, S., *Obama's $3bn for climate fund could kickstart action on global* warming, The Guardian (Nov. 14, 2014), *available at* http://www.theguardian.com/environment/2014/nov/14/obamas-3bn-climate-fund-could-kickstart-action-global-warming; *Countries pledge $9.3bn for Green Climate Fund*, The Guardian (Nov. 20, 2014), *available at* http://www.theguardian.com/environment/2014/nov/20/countries-pledge-93bn-for-green-climate-fund.

The Clean Power Plan will play a critical role in meeting the U.S. target for more stringent GHG emission reductions and provide an incentive for other countries to reduce their carbon pollution. With President Obama's latest commitment, carbon emissions reductions in the early years of the Clean Power Plan's proposed compliance period will be essential. A stronger Clean Power Plan is essential to assure that the U.S. reaches its international climate targets for 2020 and 2025. Yet industry and several states are advocating for a more gradual "glide path" that would give utilities additional years to start achieving the reductions from Building Blocks 1 and 2. States are already given significant flexibility because they are allowed to use averaging over the entire compliance period. Delaying the phase-in of Blocks 1 and 2 would weaken EPA's proposed interim targets, and delay long needed carbon pollution reductions. The interim targets should not be relaxed, but strengthened and, indeed accelerated. As discussed below, the Clean Power Plan's compliance deadline should end in 2025 and the agency should revise and strengthen the standard afterwards. Not only is a stronger Clean Power Plan needed to help meet the more ambitious 2025 target that the U.S. has agreed to achieve, but a commitment to early reductions is also vital to U.S. credibility and leverage over the critical next 12 months.

According to the United Nations Environment Programme's 2014 Emissions Gap Report, even with the U.S., China, and EU's recent pledges to limit GHG pollution, the world is not on track to achieving the emissions reductions needed to keep global temperature increases below 2 degrees Celsius above preindustrial levels by 2100[52] and avoid the worst impacts of a changing climate.[53] Further immediate action, such as heavy investments in renewable energy and energy efficiency,[54] is needed to keep global average temperature rise below the internationally agreed 2 degrees Celsius goal to avoid the most devastating consequences of climate change. Moreover, a strong Clean Power Plan alone will not be enough to achieve the reductions set out in the U.S.' pledge;[55] other federal regulatory standards being implemented under the Obama Administration will play an important role in significantly reducing GHG pollution. The proposed regulations limiting carbon emissions from new and existing power plants, combined with other regulatory actions, such as the new fuel economy standards for vehicles, mercury and air toxics standards, ozone standards, initiatives to reduce methane emissions from the oil and gas industry, and efforts to boost energy efficiency and renewable energy standards at the state level, are all needed to achieve the Obama administration's pledge, cement US leadership, and help keep global temperature rise below the internationally agreed 2 degree Celsius goal.

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[52] *See generally* United Nations Emission Program ("UNEP"), *The Emissions Gap Report 2014: A UNEP Synthesis Report* (Nov. 2013), *available at* http://www.unep.org/publications/ebooks/emissionsgapreport2014/.

[53] International parties agreed to this temperature rise limit at the Cancun Climate Change Conference in November 2010. *See* United Nations Framework Convention on Climate Change, *Cancun Climate Change Conference – November 2010,* http://unfccc.int/meetings/cancun_nov_2010/meeting/6266.php (last visited Nov. 30, 2014).

[54] *See* UNEP, supra n. 52, at Ch. 4.

[55] *Id.* at Ch. 3, p. 31.

The greenhouse gas emissions reductions required to meet the more stringent 2025 targets are achievable with the implementation of a stringent Clean Power Plan in combination with other critical federal regulatory actions.

C. The Clean Power Plan Reinforces Ongoing Changes in the Utility Sector.

A key aspect of EPA's Clean Power Plan proposal is that it will exert regulatory pressure in the same direction toward which the utility sector is already swiftly moving. Indeed, it is difficult to overstate the transformation that U.S. energy markets have undergone in recent years. Most significantly, the U.S. is decisively shifting away from coal as the primary generation source of base-load electricity, a trend that is evident in the most recent data.[56] The U.S. has seen older and less-efficient existing coal-fired power plants continuing to retire since 2012 due to increased competition with other generating resources and impending environmental regulations. Between 2008 and 2013, U.S. utilities retired approximately 20 GW of coal-fired capacity,[57] with approximately 11.3 GW retired in 2012 alone.[58] As of November, 2014, utilities had announced firm plans to retire some 75 GW of coal-fired generating capacity (or to convert it to natural gas) by 2021.[59] And according to a recent market study, a further 17 GW is "at risk" of retirement due to competition with low-cost natural gas.[60] As coal-fired capacity has declined, so has generation from the coal-fired fleet: in 2013, coal-fired EGUs accounted for 39.1 percent of U.S. generating output—slightly higher than the low of 37.4 percent reached in 2012, but still representing a 20 percent decline in market share since 2006.[61]

The decline in U.S. reliance on its coal generation has coincided with rapid domestic expansion of zero- and lower-carbon generating unit development and electricity generation. For example, April 2013 saw a record amount of electricity generated from U.S. wind resources of over 17,000 GWh—nearly as much wind-generated electricity produced in one month as U.S. wind resources delivered in all of 2005.[62] From 2011 to 2013, electricity delivered to the grid from wind generators increased by at least 28 percent (from a total of 120,177 GWh in 2011, to

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[56] EIA, AEO2014 Early Release Overview (Dec. 16, 2014), *available at* http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2014).pdf (hereinafter "AEO2014 Early Release"), at 2, Fig. 3.

[57] NERC, *2013 Long-Term Reliability Assessment* (Dec. 2013), *available at* http://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/2013_LTRA_FINAL.pdf, at 35.

[58] EIA, *Electric Power Annual, Table 4.6 (*Dec. 2013), *available at* http://www.eia.gov/electricity/annual/pdf/epa.pdf.

[59] Gilbert & Gelbaugh, *Coal Under Fire: Assessing Risk Factors and Market Impacts for Upcoming Coal Retirement Decisions* (SNL Energy, Dec. 2013); *see also* **Appendix A**.

[60] *Id.*

[61] EIA, *Short-Term Energy Outlook* (Jan. 2014), at 21, *available at* http://www.eia.gov/forecasts/steo/archives/Jan14.pdf.

[62] EIA, Electric Power Monthly (Feb. 2014), Table 1.1.A, *available at* http://www.eia.gov/electricity/monthly/current_year/february2014.pdf.

a total of 167,665 GWh in 2013).[63] Similarly dramatic has been the expansion of solar energy, which increased in generation capacity by 418 percent between 2010 and 2014.[64] The lead solar industry association forecasts that at current prices, it will take only two years to install the next 20 gigawatts of solar capacity, compared to the 40 years it took to install the first 20 gigawatts.[65] 2014 solar capacity installations are nearly double those of 2013.[66] Energy efficiency also grew rapidly during this period: utility and private spending on energy efficiency investments increased to over $12 billion in 2012,[67] and in 2011, first-year energy savings reported by utilities totaled 22 million MWh—an increase of approximately 22 percent year-over-year.[68]

Looking ahead, forecasts indicate that the shift from coal to cleaner sources of energy will continue. For example, EIA predicts in its *Annual Energy Outlook 2014 Early Release Overview* that total domestic coal-fired capacity will decrease by over 15 percent from 2012 to 2040.[69] EIA attributes this trend to slower growth in electricity demand, competition from zero- and low-carbon resources,[70] and economic changes resulting from more stringent

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[63] *Id.*

[64] EIA, Electricity Monthly Update (Apr. 2014), *available at* http://www.eia.gov/electricity/monthly/update/archive/april2014/.

[65] *See* Opening Remarks by Rhone Resch, President and CEO, Solar Energy Industries Association, at Solar Power International 2014 (Oct. 20, 2014), *available at* http://www.seia.org/news/rhone-resch-opening-remarks-spi-2014.

[66] *See* EIA, *Electric Power Monthly – August 2014*, Table 1.1.A. Net Generation from Renewable Sources: Total (All Sectors), 2004-August 2014 (Year to Date), available at http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_01_a.

[67] Business Council on Sustainable Energy, *2014 Sustainable Energy in America Factbook* (Feb. 2014), attached as **Ex. 1***,* at 4.

[68] American Council for an Energy–Efficient Economy, *2013 State Energy Efficiency Scorecard* (Nov. 2013), attached as **Ex. 2**, at 30.

[69] AEO2014 Early Release, *supra* n.56 at 14.

[70] EIA defines "renewable energy" as "energy resources that are naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Renewable energy resources include biomass, hydro, geothermal, solar, wind, ocean thermal, wave action, and tidal action." EIA, *Glossary*, http://www.eia.gov/tools/glossary/(last visited Nov. 30, 2014). Notably, while many of these generating choices are zero carbon-emitting, unfortunately all biomass-fueled energy cannot be assumed to be "carbon neutral" or zero-emitting, or even low carbon-emitting in some instances. For example, burning chipped whole trees to generate electricity has the same or higher tons CO_2/MWh output as burning coal. *See, e.g.*, Manomet Center for Conservation Sciences, *Massachusetts Biomass Sustainability and Carbon Policy Study, Report to the Commonwealth of Massachusetts Department of Energy Resources* (Walker, ed.) (National Capital Initiative Report No. NCI-2010-03) (2010), *available at* http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/biomass/biomass-sustainability-and-carbon-policy-study.html (demonstrating using modeling that the combination of greater carbon emissions per unit energy from biomass than fossil fuels, combined with the lost forest carbon sequestration associated with additional fuel harvesting, produce net CO_2 emissions that greatly exceeded those from fossil fuels—a "carbon debt" that takes decades to more than a century to pay off).

environmental regulations.[71] Similarly, NERC anticipates that 31.5 GW of net coal-fired capacity will retire by 2023.[72]

EPA notes in the preamble to the proposed rule that as coal-fired plants retire, current power sector economics suggest that they will likely be replaced with new renewable projects, energy efficiency savings, and combined cycle gas generation. Most of these new lower emitting electricity sources currently have much lower construction and operating costs than coal-fired EGUs,[73] and this trend is also likely to continue in the coming years.[74] As a result of these cost disparities, EIA's latest *Annual Energy Outlook* forecasts only 2.5 GW of additional planned coal-fired generating capacity through 2040, with nearly 90 percent of this capacity consisting of projects that are already under way.[75] Similarly, the International Energy Agency ("IEA") *World Energy Outlook 2013* predicts that over three-quarters of the capacity replacements for retired units in the U.S. will come from wind, solar, or NGCC units. EIA also expects generation from renewables to be higher than was estimated in 2013 across most of the projection period,[76] with renewable sources accounting for almost a third of the growth in generation resources from 2012 to 2040 as they become more cost-competitive with other fuels.[77] Indeed, EIA projects that renewables will remain the fastest-growing source of electric generation through 2040.[78]

In sum, the shift in the electricity generating sector from coal to lower-emitting resources has continued at a rapid pace in recent years, and forecasts of fuel costs, capital costs, and other power sector trends continue to indicate that conventional coal-fired power plants will represent a shrinking percentage of generation over the foreseeable future. In this sense, the Clear Power Plan largely reflects changes that are already happening in the electric sector, as do the individual state targets included in the proposal. For instance, Washington's emission target for 2030 is 215 lbs CO_2/MWh—ostensibly, a very low number—but this simply represents the fact that all but one of Washington's coal plants have already retired, with the

[71] AEO2014 Early Release, *supra* n.56 at 14. The Reference case includes implementation of MATS and CAIR, as well as market concerns about GHG emissions, which dampen the expansion of coal-fired capacity. *Id.*
[72] NERC, *supra* n. 56 at 10.
[73] EIA, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants* (Apr. 2013), *available at* http://www.eia.gov/forecasts/capitalcost/, at 6 (reporting that even the lowest-cost coal-fired EGU configuration has capital costs that are nearly three times higher than an advanced NGCC and 33 percent higher than onshore wind on a per-kW basis).
[74] AEO2014 Early Release, *supra* n. 56 at 14.
[75] EIA, *Annual Energy Outlook 2014* (May 2014) *available at* http://www.eia.gov/forecasts/AEO/, at Table A9; *see also* 79 Fed. Reg at 1,478.
[76] *Id.* at 15.
[77] *Id.* at 14.
[78] *Id.* at Table A8 (showing average annual growth of 1.7 percent for renewable generation through 2040).

remaining facility announced for retirement.[79] EPA's proposal will therefore advance the pace at which the electric sector is changing, but will not fundamentally alter the direct of that change.

II. The Clean Air Requires EPA To Regulate CO_2 Emissions from Fossil-Fuel Fired Power Plants Under Section 111(d)

A. EPA's Reasonable Interpretation of Section 111(d) Merits Judicial Deference

EPA's Legal Memorandum correctly describes the history of the different House and Senate-enacted versions of §111(d)(1).[80] The House version (which is the version presented in the U.S. Code) provides for standards of performance for existing sources "for any air pollutant (i) [1] for which air quality criteria have not been issued or which is not included on a list published under [CAA section 108(a)] or [2] emitted from a source category which is regulated under [section 112]." Because power plants are a source category regulated under section 112 for mercury and other hazardous air pollutant ("HAP") emissions, see 77 Fed. Reg. 9,304 (Feb. 16, 2012) (final Mercury and Air Toxics ["MATS"] rule), some industry groups have argued that the foregoing language precludes EPA from issuing section 111(d) performance standards of performance for emissions of *any* pollutants (including CO_2) from existing power plants. The Senate version, which also appears in the enacted (i.e., Statutes at Large) version of the 1990 amendments, requires standards of performance "for any air pollutant . . . which is not included on a list published under section 108(a) or 112(b) (1)(A)" of the Act.

In the Legal Memorandum, EPA correctly concludes that the enactment of these conflicting versions creates an ambiguity that EPA is authorized to resolve under step 2 of the test articulated in *Chevron U.S.A., Inc. v. NRDC*, 467 U.S. 837, 842-844 (1984).[81] The agency then offers a reasonable interpretation of the provisions as together excluding from regulation under section 111(d) not all pollutants, but only and specifically HAPs that are both listed under section 112(b) and emitted by sources (such as power plants) that are regulated under section 112.[82] Under EPA's construction, therefore, the agency may not regulate power plant mercury emissions under section 111(d), since mercury is a listed HAP and power plants are regulated under section 112 by the MATS rule, but it *must* regulate power plant CO_2 emissions under section 111(d), since CO_2 is not a HAP listed under section 112(b), notwithstanding the MATS rule.

[79] *See* TransAlta, *Centrallia*, http://www.transalta.com/us/2011/10/centralia-wa/ (last visited Nov. 21, 2014).
[80] EPA, *Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units* (June 2014), *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602-legal-memorandum.pdf, at 20-27.
[81] *Id.* at 25.
[82] *Id.* at 26-27.

EPA's proposed construction is consistent with the context and evolution of section 111(d), and it is necessary to consider the 1990 Clean Air Act Amendments against this legal backdrop. *See McFarland v. Scott*, 512 U.S. 849, 856 (1994) ("Congress legislated against this legal backdrop . . . and we safely assume that it did not intend for the express requirement of counsel to be defeated in this manner"). Historically, section 111 has served a gap-filling function to ensure that EPA had a mechanism to regulate dangerous air pollutants that were not already covered under the criteria pollutant or HAP programs. Prior to the 1990 Amendments, the HAP exclusion under section 111(d) applied only to pollutants "not included on a list published under"§112"—not to categories of sources that emitted those pollutants. 42 U.S.C. §7411(d)(1)(1977); Public Law 95-95. There is nothing in the structure or history of the 1990 Amendments to suggest that Congress meant to drastically broaden that exclusion, which has always functioned simply to ensure that EPA's section 111(d) rules do not encompass pollutant emissions already subject to regulation under Act's criteria pollutant or air toxics provisions for existing sources. EPA is therefore well within its authority to interpret the Amendments as preserving the function and scope of section 111(d) that existed prior to 1990, and is correct to interpret the statute to permit regulation of CO_2 emissions from existing EGUs under section 111(d).

B. The Industry Interpretation of Section 111(d) Is Textually and Logically Flawed, and Must Be Rejected.

Far from signaling an intent to dramatically alter the statute by greatly restricting (or, indeed, erasing) the scope of section 111(d), the structure and context of the 1990 Amendments signal the opposite concern: that EPA was not proceeding diligently *enough* to limit harmful air pollution. Indeed, in rejecting an interpretation put forth by some industry advocates that would prevent EPA from regulating under section 111(d) all "HAP or non-HAP emitted from a source category regulated under section 112," EPA has affirmed that

> [s]uch 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. Furthermore, EPA has historically regulated non-HAP under section 111(d), even where those non-HAP were emitted from a source category actually regulated under section 112. *See, e.g.,* 40 CFR 62.1100 (California State Plan for Control of Fluoride Emissions from Existing Facilities at Phosphate Fertilizer Plants). We do not believe that Congress sought to eliminate regulation for a large category of sources in the 1990 Amendments and our proposed interpretation of the two amendments to section 111(d) avoids this result.

70 Fed. Reg. 16,032 (Mar. 29, 2005) (footnote omitted).

Moreover, the Supreme Court has held that, where dealing with conflicting statutory provisions, it is appropriate to adopt a construction that is "more consonant with the functions sought to be served by the Act" and that does not "impute to Congress a purpose to paralyze with one hand what it sought to promote with the other." *Clark v. Uebersee Finanz-Korp*, 332 U.S. 480, 489 (1947); s*ee also Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. Ruckelshaus,* 719 F.2d 1159, 1165 (D.C.Cir.1983) ("A statute should ordinarily be read to effectuate its purposes rather than to frustrate them."). Here, the ends that the Act seek to advance are the protection of public health and welfare from air pollution, a goal clearly disserved by an interpretation that would bar EPA from curbing harmful CO_2 pollution under section 111(d). 42 U.S.C. §7401(b)(1). To read the statute as foreclosing existing-source standards of performance for *any* pollutant emitted by a source category regulated under section 112 would, as a practical matter, render section 111(d) inoperative as to virtually all pollutants, since the sources regulated under section 112 emit virtually every pollutant imaginable that might be subject to section 111(d) standards. The industry reading would thwart the Act's—and section 111's—core purpose of protecting public health and welfare, *see* §§7401(b)(1), 7411(b)(1)(A), since it would allow entire classes of pollutants (in this case, CO_2) to go unregulated, no matter how harmful to the public health and welfare they may be. To imply that Congress gave EPA the choice of regulating power plant emissions of *either* CO_2 *or* mercury, but not both, makes a mockery of the statute and its goal of protecting the public health and welfare.

The industry reading of section 111(d) would not even serve the purpose that some industry advocates have attributed to it—avoiding duplicative regulation of pollutants that are already being regulated under sections 108 or 112—because CO_2 is *not* being regulated under either of those two other sections. Thus, the net result of such a misguided reading would be *no* regulation of CO_2 emissions from existing power plants under any Clean Air Act program. To allow such a harmful pollutant to fall through the regulatory cracks based on the mere fortuity that EPA has decided to control emissions of *some other pollutant* from that source not only contravenes the Act's and section 111's health-and-welfare protective purpose, but also makes no sense. Time and again, the Supreme Court has declined to interpret statutes—including the Clean Air Act—in such a fashion. *See e.g., Engine Mfrs. Assn. v. South Coast Air Quality Management District*, 541 U.S. 246, 255 (2004) (rejecting reading that "would make no sense"); *Desert Citizens Against Pollution v. EPA*, 699 F.3d 524, 527-28 (D.C. Cir. 2012) (EPA permissibly rejected interpretation that "would have the anomalous effect of changing the required stringency of non- § 112(c)(6) HAPs at a given area source . . . *simply on the fortuity that the non-§ 112(c)(6) HAPs in question shared a source with one or more § 112(c)(6) HAPs*") (emphasis added); *Roberts v. Sea-Land Services*, 132 S. Ct. 1350, 1359-60 (2012) ("Under Roberts' reading, two employees who earn the same salary and suffer the same injury on the same day could be entitled to different rates of compensation based on the happenstance of their obtaining orders in different fiscal years. We can imagine no reason why Congress would have intended, by choosing the words "newly awarded compensation," to differentiate between employees based on such an arbitrary criterion.").

The industry reading also ignores clear statutory evidence that Congress intended sections 111 and 112 to work in unison, not disharmony. Congress expressly directed that the source categories to be regulated under section 112 be consistent with the list of source categories regulated under section 111. 42 U.S.C. §7412(c)(1). This cross-reference would serve no purpose if Congress had intended that HAP regulations under section 112 would prohibit EPA from regulating any and all emissions, HAP and non-HAP alike, from those sources under section 111(d). In this regard—and in effectively dismantling an entire Clean Air Act program—the industry reading would contravene the fundamental canon that statutes are to be construed to give all words and provisions effect. *See, e.g., Northwest Austin Mun. Utility Dist. No. One v. Holder*, 557 U.S. 193, 211 (2009) (rejecting statutory interpretation that would render a provision "all but a nullity . . . It is unlikely that Congress intended the provision to have such limited effect.") (citation omitted); *TRW v. Andrews*, 534 U.S. 19, 29, 31 (2001) (rejecting reading that would "in practical effect" render statutory provision "entirely superfluous in all but the most unusual circumstances . . . . It is a cardinal principle of statutory construction that a statute ought, upon the whole, to be so construed that, if it can be prevented, no clause, sentence, or word shall be superfluous, void, or insignificant. Were we to adopt Andrews' construction of the statute, the express exception would be rendered insignificant, if not wholly superfluous.") (citations and internal quotation marks omitted); *Mayle v. Felix*, 545 U.S. 644, 662 (2005) (rejects reading under which statutory limitations period "would have slim significance"). Along these same lines, the industry reading would effectively treat the 1990 Amendments as an implied repeal of section 111(d). Courts generally reject claims of implied repeal, and will only accept them when there is "overwhelming evidence" and "when the earlier and later statutes are irreconcilable." *E.M. AG Supply v. Pioneer Hi-Bred International*, 534 U.S. 124, 137, 141-42 (2001) (citations and internal quotation marks omitted). Neither condition applies in this instance.

Nor is there any evidence that Congress meant to strip section 111(d) of its utility in such a cryptic manner. If Congress had meant to significantly restrict the applicability of section 111(d)(1), it would have said so clearly. *See Board of Trustees v. Roche Molecular Systems*, 131 S. Ct. 2188, 2198-99 (2011) ("[I]f Congress has intended such a sea change . . . it would have said so clearly"); *Whitman v. Am. Trucking Ass'ns*, 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."). This point is particularly salient in the case of the 1990 Clean Air Act Amendments, which were universally understood to *tighten*, not loosen, the statute's pollution control measures. *See, e.g.*, Remarks of President Bush Upon Signing S. 1630, 26 Weekly Comp. Pres. Doc. 1824 (Nov. 19, 1990) (reprinting the President's signing statement of Nov. 15, 1990) ("This legislation isn't just the centerpiece of our environmental agenda. It is simply the most significant air pollution legislation in our nation's history, and it restores America's place as the global leader in environmental protection."). To assert that a landmark bill praised for its environmental stringency actually eviscerates key provisions of the statute *sub silentio* borders on the absurd, and EPA is correct to reject this flawed reasoning in favor of a construction that actually advances the statute's goals. *See Griffin v. Oceanic Contractors, Inc.*, 458 U.S. 564, 575 ("[I]nterpretations of a statute which would produce absurd results are to be avoided if alternative interpretations consistent with the legislative purpose are available."); *American Water Works Assn v. EPA*, 40 F.3d 1266, 1271 (D.C. Cir. 1994) (where reading of statute would lead to absurd results, statute has no plain meaning and is proper subject of construction by agency and courts).

In short, given the conflicting amendments, EPA is authorized to adopt a reasonable interpretation of the statute. *Northeast Hosp. Corp. v. Sebelius*, 657 F.3d 1, 11 (D.C. Cir. 2011) ("We are thus faced with two inconsistent sets of statutory provisions. Northeast points us to provisions that tie entitlement to payment and state that once a person enrolls in Part C, payments are no longer made under Part A. The Secretary points us to other provisions that assume it is possible to be both entitled to benefits under Part A and enrolled in Part C. Under these circumstances, we conclude that the Medicare statute does not unambiguously foreclose the Secretary's interpretation."); *Chevron*, 467 U.S at 842-43. And, for reasons stated above, EPA's interpretation comports with the context, history, structure, and purpose of the Clean Air Act. As such, its construction should merit judicial deference in any legal proceeding challenging its authority to regulate CO_2 emissions from existing EGUs under section 111(d).

C. EPA's Interpretation of Section 111(d) is Proper In Any Event.

Alternatively, if the 1990 House and Senate language were to be deemed in irreconcilable conflict (i.e., if the conflicting amendments cannot both be given literal effect, and if EPA lacks authority to adopt a reasonable interpretation to resolve the conflict), then both chambers' 1990 amendments to section 111(d) must fail. In that scenario the language would revert to the pre-1990 version, which authorizes §111(d) regulation of any air pollutant "for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) or 7412(b)(1)(A) of this title." Since CO_2 are listed neither under §7408(a) nor §7412(b), under this scenario as well EPA would be authorized to promulgate section 111(d) guidelines for power-plant CO_2 emissions.

Finally, even if the House amendment were deemed to be the only applicable amendment, the same outcome should obtain. First, the Supreme Court has recently noted EPA's practice of adopting context-appropriate interpretation of the Clean Air Act phrase "air pollutant." *Utility Air Regulatory Group v. EPA ("UARG")*, 134 S. Ct. 2427, 2439-42 (2014). For example,

> [t]he Act authorizes EPA to enforce new source performance standards (NSPS) against a pre-existing source if, after promulgation of the standards, the source undergoes a physical or operational change that increases its emission of "any air pollutant." § 7411(a)(2), (4), (b)(1)(B). EPA interprets that provision as limited to air pollutants *for which EPA has promulgated new source performance standards*. 36 Fed.Reg. 24877 (1971), codified, as amended, 40 C.F.R. § 60.2; 40 Fed.Reg. 58419 (1975), codified, as amended, 40 C.F.R. § 60.14(a).

Id. 2440 (emphasis in original). Similarly here, a context-appropriate reading of "any air pollutant," when used with the phrase "emitted from a source category which is regulated under section 7412," would encompass only an air pollutant *listed under section 112* that is emitted from such a source category.

Considered from another angle, sources are not regulated in the abstract, but regulated with regard to specific pollutants. Hence, any interpretation of the phrase "regulated under section 7412" must include an implied phrase indicating *what* the source in question is being regulated *with regard to*. Under the industry interpretation, this implied phrase is "with regard to any pollutant," i.e., "emitted from a source category which is regulated under section 7412 [with regard to any pollutant]." A much more rational interpretation would include the implied phrase "with regard to HAPs," i.e., "emitted from a source category which is regulated under section 7412 [with regard to any HAPs]," which not only effectuates rather than frustrates the purpose of the statute, as discussed above, but accords with the kind of contextually-appropriate reading of the statute described in *UARG*.

An examination of the *historical* context surrounding the House language militates in the same direction. Prior to the 1990 Amendments, EPA had been tasked with listing hazardous air pollutants for regulation under section 112. The pre-1990 language of section 111(d) reflected this fact insofar as it referenced the "list published under section . . . 7412(b)(1)(A)." Frustrated with the agency's slow progress on this front, Congress took it upon itself to list 190 HAPs by statute and then delegated to EPA the authority and responsibility to regulate emissions of those HAPs on a source-by-source basis. It is for this reason that the House amendment deleted the pre-1990 references to the list of HAPs, which was now defined by statute rather than EPA regulation, and replaced it with a reference to source categories, which were now the subject of EPA regulation for the HAP emissions. Given this historical context, it is clear that the House language was meant to preserve the status quo, under which EPA could not regulate a source's HAP emissions under section 111(d) if it was already doing so under section 112, rather than silently introduce a new and massive exclusion into the statute that effectively rendered section 111(d) a dead letter.

Second, the literal language of the House amendment favors EPA's interpretation of the statute. As EPA recently observed in a legal brief opposing the industry interpretation of section 111(d),

> even if one disregards the Senate amendment and considers only the House amendment, as Petitioner and amici advocate, that text does not unambiguously say what Petitioner and amici believe it says. In fact, a truly "literal" reading (see Amici Br. at 4) results in precisely the opposite conclusion.[83]

The relevant portion of section 111(d), as amended by the House, contains a string of three exclusionary clauses, separated from each other by "or":

> The Administrator shall prescribe regulations . . . under which each State *shall submit* to the Administrator a plan which establishes standards of performance for any existing source *for any air pollutant [1]* for which air quality criteria have not been issued *or [2]* which is not included on a list published under section

[83] Response to Petition at 28, *In re: Murray Energy Corp.*, No. 14-1112 (D.C. Cir. Nov. 3, 2014).

> 7408(a) of this title *or [3]* emitted from a source category which is regulated under section 7412 of this title . . . .

42 U.S.C. § 7411(d)(1) (emphasis and internal numbering added). Because Congress used the conjunction "or" rather than "and," the three exclusions arguably should be viewed as alternatives, rather than requirements to be imposed simultaneously. *See U.S. v. Woods*, 134 S.Ct. 557, 567 (2013) ("Moreover, the operative terms are connected by the conjunction "or." While that can sometimes introduce an appositive . . . its ordinary use is almost always disjunctive, that is, the words it connects are to 'be given separate meanings.'").[84] In other words, section 111(d) "literally" provides that the Administrator may require states to establish standards for an air pollutant so long as *either* air quality criteria have not been established for that pollutant, *or* one of the other two remaining criteria is met. Air quality criteria have not been issued for CO_2. Thus, under a truly literal reading of section 111(d)(1) as amended by the House, whether power plants have been regulated under section 7412—and for what pollutant—is irrelevant: the CO_2 regulations at issue are authorized.

To compound the ambiguity, the third exclusionary clause in the House's version of section 7411(d)(1), which provides the basis for the industry interpretation of section 111(d), differs from the first two in that it does not contain a negative:

> [EPA may require states to submit plans establishing standards for] any air pollutant [1] for which air quality criteria have *not* been issued or [2] which is *not* included on a list published under section 7408(a) of this title or [3] emitted from a source category which is regulated under section 7412 of this title . . . .

42 U.S.C. § 7411(d)(1) (emphasis and internal numbering added). The industry argument presumes that the negative from the second clause was intended to carry over into the third (i.e., implicitly inserting another "which is not" before "emitted from a source category"), but that is not what the text actually says; instead, it states that EPA may require standards for "any air pollutant . . . emitted from a source category which is regulated under section 7412." 42 U.S.C. § 7411(d)(1). Thus, read literally, the House's version of section 7411(d) means the exact opposite of what petitioners and amici argue, and provides that EPA may regulate emissions of a pollutant from a source category where that category *is* regulated under section 7412. Other observers have made this argument as well:

> As amended by the House amendment language, §111(d) would direct EPA to regulate, through state plans, "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) of this title or emitted from a source category which is regulated under

[84] Merriam Webster's Dictionary defines "or" as "a function word [used] to indicate an alternative <coffee *or* tea> <sink *or* swim>." *See* Merriam Webster, Definition of "Or," http://www.merriamwebster.com/dictionary/or (last visited Nov. 19, 2014).

Section 7412 of this title . . . ." The use of the conjunction "or" to join the two "which" clauses in (i) is most naturally read such that only one of the "which" conditions must be met in order for EPA to have regulatory authority under §111(d). This reading would provide EPA authority to regulate an existing source for any air pollutant that is not a criteria pollutant, regardless of the meaning of the "or emitted" clause that is the subject of the two competing 1990 CAA Amendments.[85]

As discussed above, the history, purpose, and structure of the Clean Air Act, of the 1990 Amendments, and of section 111(d) all persuasively show that EPA may regulate CO_2 emissions from existing EGUs under section 111(d). Accordingly, under any acceptable heuristic, the Clean Power Plan is an appropriate exercise of EPA's authority under that provision of the statute and is on firm legal footing.

III. EPA's Determination of the BSER is Technically Feasible and Legally Justified.

A. Statutory Background: Section 111(d) of the Clean Air Act

Section 111(d) of the Clean Air Act requires EPA to issue regulations that establish a state implementation plan procedure whereby states establish standards of performance for any existing source for any air pollutant to which a standard of performance would apply if such existing source were a new source. 42 U.S.C. §7411(d)(1)(A). Section 111(d) provides that this procedure must be similar to the state implementation plan process for regulating criteria pollutants under Section 110 of the Act. *Id.* §7411(d)(1). Section 111(d) Implementing Regulations, promulgated by EPA in 1975, establish a process for adoption and submittal of state plans, allocating responsibility for the various steps in this process to EPA or the states. 40 C.F.R. §§ 60.20-60.29.[86]

First, concurrently upon or after proposal of standards of performance for the control of a designated air pollutant from new sources, EPA must issue a draft guideline document containing information pertinent to the control of the designated pollutant from existing sources. *Id.* §§ 60.22(a). The guideline document must include, among other information, an "emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent

[85] Nordhaus & Gutherz, *Regulation of CO_2 Emissions From Existing Power Plants Under §111(d) of the Clean Air Act: Program Design and Statutory Authority*, 44 ELR 10,366, 10,377 n.89 (May 2014). Additional support for construing section 111(d) to permit standards of performance for such emissions appears in Konschnik, K., *EPA's 111(d) Authority – Follow Homer and Avoid the Sirens*, LegalPlanet (May 28, 2014),http://legal-planet.org/2014/05/28/guest-blogger-kate-konschnik-epas-111d-authority-follow-homer-and-avoid-the-sirens/ (incorporated herein by reference).

[86] *Standards of Performance for New Stationary Sources, State Plans for the Control of Certain Pollutants from Existing Facilities*, 40 Fed. Reg. 53,340 (Nov. 17, 1995).

stringency can be achieved." *Id.* § 60.22(b)(5). Second, each state must adopt and submit to EPA a plan establishing standards of performance or "emission standards" for the designated pollutant which, as a general rule, shall not be less stringent than the corresponding emission guideline. *Id.* §§ 60.23(a)(1), 60.24(c). Third, EPA must approve the states' plans, or issue a plan for any state that fails to submit a satisfactory plan, or that fails to submit a plan within the time prescribed. *Id.* §§ 60.27(b)-(c).

In this rulemaking, the proposed Clean Power Plan is EPA's draft guideline document, published after EPA's proposed standards of performance for new fossil fuel-fired EGUs issued in January 2014, and concurrently with the proposed standards of performance for modified and reconstructed EGUs.[87] The guideline document contains (1) an assessment of technical potential and reasonableness of costs of EPA's proposed systems of emission reduction or "building blocks," (2) the agency's determination that the "best system of emission reduction" ("BSER") includes, or makes use of, those four building blocks, and (3) its proposed emission guidelines or "state goals," computed through the application of the BSER to each state's affected sources on a state-wide basis.

B. EPA Determines the "Best System of Emission Reduction" Under Section 111.

States must develop plans that establish standards of performance for existing sources under Section 111(d). 42 U.S.C. § 7411(d)(1)(A). Section 111(a)(1) of the Act defines "standard of performance" 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 non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." *Id.* § 7411(a)(1). The regulatory definition of "emission guideline," which is similar to the statutory definition of "standard of performance," provides that the guideline must reflect the application of the BSER. 40 C.F.R. § 60.22(b)(5). The definition has three key elements: first, the standard of performance and the emission guideline must reflect the application of the BSER; second, the agency must consider costs, as well as health, environmental, and energy impacts; and third, the BSER must be adequately demonstrated.

Neither the Act nor the Implementing Regulations define the term "best system of emission reduction," but the statute does make it clear that it is EPA's task to make this determination. As the agency notes in its Legal Memorandum to the Clean Power Plan, while the D.C. Circuit has not interpreted or reviewed EPA's interpretation of Section 111(d), during the past four decades it has issued a number of decisions concerning several aspects under Section 111(b) rule makings, in particular regarding the statutory definition of "standard of

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[87] *Clean Power Plan*, 79 Fed. Reg. 34,830; *Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units*, 79 Fed. Reg. 1,430 (Jan. 8, 2014); *Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units*, 79 Fed. Reg. 34,960 (June 18, 2014).

performance," which applies to both new and existing sources.[88] EPA so recognized in the preamble to its Implementing Regulations:

> "[T]he general principle (application of best adequately demonstrated control technology, considering costs) *will be the same in both cases*, the degrees of control represented by EPA's emission guidelines will ordinarily be less stringent than those required by standards of performance for new sources because the costs of controlling existing facilities will ordinarily be greater than those for control of new sources."

40 Fed. Reg. at 53,341 (emphasis added).

1. EPA has Authority to Determine the BSER Based on Consideration of the Statutory Factors.

The legislative history of Section 111 and the D.C. Circuit's interpretation of the term "best system of emission reduction" show that EPA has authority to determine the BSER for both new and existing sources. The statutory factors impose important limits on EPA's discretion to make this determination—the agency must determine the "best" system considering the degree of emissions reductions such system may generate,[89] as well as other factors (costs, non-air quality health impacts, and environmental impacts) required by the statute).

Congress added Section 111 to the Clean Air Act in 1970. In Section 111(a)(1), Congress defined the term "standard of performance" 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* that the EPA determines has been adequately demonstrated." Pub. L. No. 91-604, § 111, 84 Stat. 1676 (1970) (emphasis added).

In 1970 Congress amended Section 111(a)(1) to require that the standard of performance for new sources "reflect the degree of emission limitation and the percentage reduction achievable through application of the *best technological system of continuous emission reduction*" taking into consideration costs, non-air quality health and environmental impacts, and energy requirements. Pub. L. No. 95-95, § 109, 91 Stat. 685 (1977) (emphasis added). Congress defined the term "technological system of continuous emission reduction" as "*a technological process for production and operation by any source* which is inherently low-polluting or nonpolluting." *Id*. (emphasis added.) Congress, however, did not impose this restriction on existing sources, and made it clear that "standards for existing sources should be

[88] EPA, *Legal Memorandum, supra* n. 80, at 10-11.

[89] *See Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) ("[T]he Senate would have required that standards reflect 'the *greatest degree of emission control* which the Secretary determines to be achievable through application of the latest available control technology, processes, operating methods, or other alternatives.'" (emphasis added.))

based on available means of emission control that were *not necessarily technological*." H.R. Rep. No. 95-564 (1977) (Conf. Rep.) (emphasis added).

In the 1990 Clean Air Act Amendments, Congress repealed the requirement that the best system of emission reduction be "technological," going back to the original requirement enacted in 1970 that required the standard of performance to be based on the application of the "best system of emission reduction," which must take into account costs, non-air quality health and environmental impacts, and energy requirements, and must be adequately demonstrated. Pub. L. No. 101-549, § 403, 104 Stat. 2399 (1990). As noted, today this definition applies both to new and existing sources.[90] Thus, the "best system of emission reduction" is not limited to technological controls implemented directly at the affected sources. As we explain below, the BSER allows for reliance on a "system" that may include measures to decrease emissions by reducing the utilization of those sources, so long as EPA adequately considers the required statutory factors.

The D.C. Circuit has held that a "best system of emission reduction" that is "adequately demonstrated" is "one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably 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). The performance standard must be "achievable because it has been achieved." *Natural Res. Def. Council v. EPA*, 655 F.2d 318, 330 (D.C. Cir. 1981) (citing cases). But "[w]hile not at the level that is purely theoretical or experimental, [the standard] need not necessarily be routinely achieved within the industry prior to its adoption." *Essex Chem. Corp.*, 486 F.2d at 433-34. "'Adequately demonstrated' does not mean that existing [sources] must be capable of meeting the standard; to the contrary, '(s)ection 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present.'" *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 787 (citing *Portland Cement Ass'n*, 486 F.2d 375 at 391. Recognizing the "technology-forcing" character of the statute, the Court has reasoned that "EPA does have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard." *Sierra Club*, 657 F.2d at 364.

After EPA identifies the emission levels that are achievable with adequately demonstrated systems of emission reduction, the agency must "weigh cost, energy, and environmental impacts in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present." *Id.* at 330 (D.C. Cir. 1981). The statutory factors which EPA must weigh are "broadly defined and include within their ambit subfactors such as technological innovation." *Id*. at 346. EPA's choice of a given standard "will be sustained unless the environmental or economic costs of using the technology are exorbitant." *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) (citing *Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 786). EPA's standards of performance will meet the cost

[90] EPA, *Legal Memorandum*, *supra* n. 80, at 6-8.

test unless the costs of meeting them "would be greater than the industry could bear and survive." *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975).

C. EPA Has Proposed Two BSER Determinations under the Clean Power Plan.

In this rulemaking, EPA is proposing two alternative approaches for determining the BSER, each of which is based on four sets of measures or "building blocks" that EGU owners and operators, as well as states have for several years been implementing for the purpose of reducing emissions of air pollutants, including CO_2, from these sources.[91] These proposed measures, and the resulting proposed BSER determinations, are in accordance with President Obama's instruction to EPA to "ensure, to the greatest extent possible, that [EPA] … develop approaches that allow the use of market-based instruments, performance standards, and other regulatory flexibilities; [and] ensure that the standards enable continued reliance on a range of energy sources and technologies."[92]

The proposed building blocks are: (1) Building Block 1: reducing the carbon intensity of generation at affected coal-fired steam EGUs through heat rate improvements; (2) Building Block 2: reducing emissions from coal-fired steam EGUs by substituting generation at those EGUs with generation from less carbon-intensive affected EGUs, namely, existing and "under construction" natural gas combined cycle units ("NGCCs," also known as combined cycle gas turbines, or CCGTs); (3) Building Block 3: reducing emissions from affected EGUs by substituting generation at those EGUs with expanded low- or zero-carbon generation, including renewable energy and nuclear generation; and (4) Building Block 4: reducing emissions from affected EGUs through demand-side energy efficiency. The first BSER approach comprises the combination of all four building blocks, and the second BSER approach consists of Building Block 1 plus the reduced utilization of affected EGUs, quantified in specific amounts through the application of Building Blocks 2, 3, and 4.

The recognition of the integrated nature of the electric grid is central to both BSER approaches. Whether Building Blocks 2, 3, and 4 are components of the BSER or not, the electric grid includes all generators (coal-fired steam EGUs, natural gas-fired EGUs, renewable generators) and electricity consumers.[93] If a generator is not available or if demand increases, the grid operator dispatches other generation facilities or increases output. Similarly, when demand decreases due to the implementation of demand-side energy efficiency, the grid

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[91] *Id.* at 10.

[92] *Presidential Memorandum -- Power Sector Carbon Pollution Standards*, Section 1(c) (June 25, 2013), *available at* http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[93] EIA, *What Is the Electric Grid and What Are Some of the Challenges It Faces*, September 16, 2014, *available at* http://www.eia.gov/energy_in_brief/article/power_grid.cfm; Doniger, D., *Questions and Answers on the EPA's Legal Authority to Set "System-Based" Carbon Pollution Standards for Existing Power Plants under Clean Air Act Section 111(d)*, NRDC Issue Brief, (Oct. 2013), *available at* http://www.nrdc.org/air/pollution-standards/files/system-based-pollution-standards-IB.pdf, at 5.

operator instructs generation facilities to reduce their output.[94] In addition, power plant owners take into account the existence and operation other units in the grid in making decisions to construct, modify, and retire individual generation units.

According to EPA, a BSER determination that recognizes the integrated nature of the electric system is consistent with the way in which the industry addresses resource planning issues. In regulated states, utilities generally develop integrated resource plans that set forth their strategies for meeting future demand for electricity services in a cost-effective manner. These plans may include measures from Building Blocks 2, 3, and 4. In non-regulated states, independent system operators ("ISOs") and regional transmission organizations ("RTOs") administer capacity auctions where owners of existing EGUs, developers of renewable capacity, and developers of demand-side resources all compete to provide potential resources for meeting projected electricity demand. 79 Fed. Reg. at 34,881.

Below we offer additional support for EPA's proposed second approach—BSER as the combination of Building Block 1 plus the reduced utilization of affected sources, quantified in specific amounts from the measures comprised in Building Blocks 2, 3, and 4. Enforcement would be simpler and more straightforward under this approach because affected sources would be accountable for the required emissions reductions; no separate oversight and enforcement of a multitude of dispatch, renewable energy, and energy efficiency measures would be needed.

D. The BSER Can Comprise Building Block 1 Plus Reduced Utilization at Levels Commensurate with Building Blocks 2, 3, and 4.

Under the second BSER approach, EPA proposes that the BSER entails not only improving the efficiency of affected fossil fuel-fired EGUs through supply-side improvements, but also reducing their utilization through the implementation of lower or zero-emitting generation and through electricity demand reductions. Specifically, EPA proposes that the BSER consists of Building Block 1 plus the reduction of CO_2 emissions from affected fossil fuel-fired EGUs achievable through reductions in generation that are quantified through the implementation of measures in Building Blocks 2, 3, and 4. *Id.* at 34,889. The amount of generation from the increased utilization of NGCC units (Building Block 2) would determine a portion of the amount of reduced generation from affected fossil fuel-fired steam EGUs, and the amount of generation from the use of renewable energy and avoided emissions through demand-side energy efficiency (Building Blocks 3 and 4) would determine a portion of the amount of the generation reduction for all affected EGUs—both coal-fired steam EGUs and NGCC units.[95]

EPA explains that this approach meets the BSER criteria because reduced generation is technically feasible due to an affected source's ability to limit its own operations, and because

[94] Konschnik & Peskoe, *supra* n. 290, at 4.
[95] EPA, *Legal Memorandum*, *supra* n. 80, at 80-81.

of the emissions reductions that would be achieved from the application of all the measures involved, its reasonable cost, its promotion of technological development and, in particular, the fact that this approach would contribute to maintain the reliability of the system through the demand reductions that would result from the implementation of demand-side energy efficiency measures.[96]

In the power sector, CO_2 emissions reductions at fossil fuel-fired EGUs can be achieved by reducing both the EGU's emission rate and its electricity output. Heat rate improvements at affected EGUs are aimed at reducing these sources' emission rate, and annual emissions limits can address the potential of a rebound effect from improving the efficiency of generation at fossil fuel-fired sources. As long as the EGU does not increase its output significantly, these measures will lead to a reduction in the EGU's CO_2 emissions. In addition, re-dispatch to existing and under-construction NGCC units, renewable energy, and demand-side energy efficiency are aimed at reducing affected sources' output and thus their overall mass CO_2 emissions.[97]

The distinction between "inside the fence line" and "beyond the fence line" measures is largely artificial and not meaningful.[98] All of the emission reductions measures under consideration, whether implemented directly at the affected source or beyond the source, translate into emissions reductions *from* such sources. Because of the integrated nature of the grid, the implementation of these measures allows affected EGUs to reduce their output, and thus, their own CO_2 emissions.[99] In other words, CO_2 emissions reductions are occurring at the affected sources due to changes in generation at those sources.[100] Therefore, all of the measures EPA is considering under the four Building Blocks are effectively "at the unit" or "inside the box" measures that reduce affected EGUs' utilization, because these measures are being and can be implemented or sponsored by owners and operators of affected sources.[101] And because all of these measures are "inside the box," EPA should set the stringency of the emission guideline based on the universe of those measures.

Basing the BSER in whole or in part on "reduced utilization" has support under other Clean Air Act programs as well as precedent under EPA's prior 111(d) rulemakings.

1. EPA's Interpretation that the BSER Can Include Reduced Utilization of Affected Sources is a Permissible Construction of the Clean Air Act.

EPA's interpretation that the BSER can include the reduced utilization of affected sources is a permissible interpretation of the Act. The legislative history of the 1970 Clean Air

[96] *Id.* at 15.
[97] Nordhaus & Gutherz, *supra* n. 85, at 10,381.
[98] *Id*. at 10,383, n. 133.
[99] *Id*.
[100] Monast et al., *Regulating Greenhouse Gas Emissions from Existing Sources: Section 111(d) and State Equivalency*, 42 ELR 10,206, 10,209 (2012).
[101] EPA, *Legal Memorandum*, *supra* n. 80, at 77-78.

Act Amendments "indicates that Congress recognized that emitting sources could comply with pollution control requirements by reducing production, including retiring." *Id.* at 34,889. In its proposed amendments, the Senate's Committee of Public Works stated that the protection of public health, as required by the national ambient air quality standards and the emission standards for hazardous air pollutants, would require major action throughout the country, whether in the form of technology controls or retirements: "[m]any facilities may require major investments in new technology and new processes. Some facilities may need altered operating procedures or a change of fuels. *Some facilities may be closed*." S. Rep. No. 91-1196 (1970) (emphasis added).

During its deliberations, the Senate Committee raised concerns with respect to basing the ambient air standards on the concept of technical feasibility, concluding, nevertheless, that existing sources should either meet the required standard or close down:

> "In the Committee discussions, considerable concern was expressed regarding the use of the concept of technical feasibility as the basis of ambient air standards. The Committee determined that 1) the health of people is more important than the question of whether the early achievement of ambient air quality standards protective of health is technically feasible; and, 2) the growth of pollution load in many areas, even with application of available technology, would still be deleterious to public health.
>
> Therefore, the Committee determined that *existing sources of pollutants either should meet the standard of the law or be closed down*, and in addition that new sources should be controlled to the maximum extent possible to prevent atmospheric emissions."

S. Rep. No. 91-1196, at 2-3 (1970) (emphasis added).

The legislative history thus suggests that Congress intended for EPA to impose stringent standards under different Clean Air Act programs that, as a practical matter, could result in reduced utilization of the sources or entities regulated under those programs.

Congress itself has established standards under the Act whose practical effect has been the reduced utilization, including the closure, of some of the regulated units. For example, under Title IV's Acid Rain Program, Congress imposed a tonnage limitation on SO_2 emissions from affected electric generating units through the use of allowances, which had to be implemented in two phases: Phase I, in effect between 1995 and 1999, covered the dirtiest large generating units (also called "Table A" units), and Phase II, which went into effect in 2000, covered the rest of the electric generating units in the country. 42 U.S.C. § 7651c(a)(1).[102]

Title IV required Table A units that elected to comply with Phase I "by reducing utilization of the unit as compared with its baseline or by shutting down the unit," to submit a reduced utilization plan that specified the unit(s) that would provide electrical generation to compensate for the reduced output at the affected unit, or a demonstration that the reduced utilization would be accomplished through energy conservation or improved unit efficiency. *Id.* § 7651g(c)(B). A Table I unit thus could designate any Phase II unit as a "compensating unit" if the latter was in the Table I unit's dispatch system or had a contractual arrangement with the Table I unit.[103] Several utilities complied with the Act using this provision, among other compliance options.[104] For example, Georgia Power Company designated ten Phase II units under Phase I and employed a reduced utilization plan that provided for increased unit efficiency and sulfur-free generation.[105]

Interpreting the term "best system of emission reduction" under Section 111 as including measures to decrease emissions by reducing the utilization of affected sources is consistent with the Act's primary purpose of encouraging air pollution prevention by states (as well as the federal and local governments). *Id.* § 7401(c). In its findings and declaration of the Act's purposes, Congress provided "that air pollution prevention (that is, the reduction or elimination, *through any measures,* of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of States and local governments." *Id.*§ 7401(a)(3) (emphasis added).

2. Section 111 Authorizes EPA to Limit the Quantity of Emissions of Air Pollutants from, and Thus to Reduce the Utilization of, Affected Sources.

As noted above, Section 111 of the Act defines "standard of performance" 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* that the EPA determines has been adequately demonstrated. 42 U.S.C. § 7411(a)(1) (emphasis added). In addition, the Implementing Regulations prescribe that the emission guideline must reflect the application of the BSER that has been adequately demonstrated for existing sources, and the time within which compliance with "emission standards" of equivalent stringency can be achieved. 40 C.F.R. § 60.22(5).

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[102] *See* Montero, *Voluntary Compliance with Market-Based Environmental Policy: Evidence from the U.S. Acid Rain Program*, J. of Political Econ. 107:5 (1999), attached as **Ex. 3**, at 6.
[103] EIA, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*, DOE/EIA-0582(97) (Mar. 1997), attached as **Ex. 4**, at 1.
[104] *Id*. *See also* Montero, *supra* n. 102, at 12.
[105] EIA, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities*, *supra* n. 104, at 19.

Although Section 111 and the Implementing Regulations do not define the terms "emission limitation" or "emission standards," Section 302(k) of the Act defines both terms as a requirement established by the states (in the case of emission standards) or by EPA "which limits the *quantity*, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction…" 42 U.S.C. § 7602(k) (emphasis added). Authority to limit the quantity of emissions logically carries with it the power to interpret the BSER as involving requirements to reduce the utilization of affected sources.

In prior emission guidelines under Section 111(d) and Section 129 of the Act, EPA has determined that the BSER included measures implemented outside the source's boundaries that reduced their utilization and thus their emissions. For example, EPA has required affected incinerators to develop waste management plans in order to reduce the amount of waste that is incinerated at those sources. Subpart Ec, which contains the emission guidelines for existing hospital, medical, and infectious waste incinerators, requires state plans to include waste management plan requirements that are "at least as protective" as the applicable requirements for new sources of the same type. 40 C.F.R. § 60.35e. Such requirements, contained in Subpart Ec, the standards of performance for new waste incineration facilities, provide that the owner or operator of an affected facility must prepare a waste management plan for separating solid waste components from the health care waste stream in order to reduce the amount of toxic emissions from incinerated waste. 40 C.F.R. § 60.55c.

In addition, Subpart DDDD, the emission guidelines for commercial and industrial solid waste incineration units, requires affected sources to submit waste management plans that identify "both the feasibility and the methods used to reduce or separate certain components of solid waste from the waste stream in order to reduce or eliminate toxic emissions from incinerated waste." 40 C.F.R. § 60.2620. Similar requirements apply to "other" solid waste incineration units under Subpart FFFF. 40 C.F.R. § 60.3012.

Waste management measures under all these regulations are intended to reduce emissions through the reduction of inputs. In the preamble to the final emission guidelines for existing hospital, medical, and infectious waste incinerators, EPA explained that through the development of waste management programs, health care facilities "can achieve significant reductions in their waste stream, reduce the volume of waste to be incinerated, and thereby reduce the amount of air pollution emissions associated with that waste."[106] Thus, the agency has previously contemplated that certain measures that are not implemented directly at the affected source can be used to reduce inputs in the combustion process, and thus the utilization of these sources, without altering the technology by which those sources produce and control emissions of air pollutants.[107]

[106] *Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Hospital/Medical/Infectious Waste Incinerators*, 62 Fed. Reg. 48,348, 48,359.
[107] Nordhaus & Gutherz, *supra* n. 85, at 10,373.

EPA's regulation of hospital, medical, and infectious waste treatment has increased the costs of incineration and, as a practical matter, has caused the closure of incinerators in favor of alternative compliance options.[108] The number of hospital, medical, and infectious waste incinerators decreased from over 2,000 units in the mid-1990s to 57 in 2008.[109] In addition, medical incinerators have increasingly contracted more commercial waste companies to manage their waste instead of incinerating it in-house, as used to be done in the past. Outsourcing waste management to commercial waste treatment companies today is the most common compliance option for medical incinerators.[110]

The availability of waste management measures for compliance has also resulted in a decrease in the percentage of medical waste incinerated.[111] As costs of incineration have increased, incineration unit owners or operators have used alternative treatment methods, such as training staff to segregate waste more effectively, and autoclaving followed by disposal of the treated waste in landfills.[112] These two trends have also contributed to reduce the share of hospital, medical, and infectious waste being incinerated, and thus the utilization of these units.[113]

E. EPA Must Revise its Proposed BSER Approaches to Include Oil-Fired and Natural Gas-Fired Units Under Building Block 1.

Under Building Block 1, EPA has estimated an average six percent improvement of the coal-fired steam EGUs in each state. EPA proposes to base this estimate on coal-fired steam EGUs *only* because the potential for reductions is "significantly greater" from these EGUs. 79 Fed. Reg. at 34,859. Even though potential heat rate improvements in NGCCs are not as significant as in coal-fired steam EGUs,[114] EPA should also estimate heat rate efficiency upgrades from natural gas-fired units, and make this type of efficiency upgrades available for compliance by these sources. Stationary combustion turbines are also a regulated source

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[108] EPA redeveloped the 1997 emission guideline for these incinerators in response to the D.C. Circuit's concerns about the methodology employed to calculate the MACT floors under Section 129. The agency identified that, under the re-developed standards, autoclaving, commercial medical waste disposal, and hauling of medical waste to municipal waste combustors would likely be used as alternative compliance options. Memorandum from T. Holloway to K. Patel, U.S. EPA, *Revised Compliance Costs and Economic Inputs for Existing HMIWI* (July 6, 2009), attached as **Ex. 5**, at 12-13.
[109] Heller & Nourani, *Economic Impacts of Revised MACT Standards for Hospital/Medical/Infectious Waste Incinerators*, Final Report, RTI Project No. 0209897.002.036 (Oct. 2008), attached as **Ex. 6**, at 2-16.
[110] *Id.* at 2-17.
[111] *Id.* at 2-16.
[112] *Id.* at 3-3
[113] *Id.* at 2-16.
[114] Burtraw & Woerman, Resources for the Future, *Technology Flexibility and Stringency for Greenhouse Gas Regulations*, Discussion Paper 13-24 (July 2013), *available at* http://www.rff.org/RFF/Documents/RFF-DP-13-24.pdf, at 9.

category under Section 111, and under EPA's proposal they would not be subject to emission reduction requirements in the form of reductions in carbon intensity.

EPA needs to estimate achievable heat rate improvements, not just from existing and under-construction NGCCs currently covered under Building Block 2, but also from existing simple-cycle combustion turbines ("CTs"). As we explained in our comments to EPA's proposed carbon pollution standards for new EGUs, new small combustion turbines would not covered under the Section 111(b) standard if they operate at capacity factors of less than 33 percent.[115] We urge EPA to finalize a Section 111(b) standard that covers these new CTs, and to also cover all existing CTs under the Section 111(d) emission guideline. As EPA notes, measures to improve affected sources' heat rates are a common and well-established practice in the industry. Heat rate improvements cause fuel to be used more efficiently, thus reducing the adverse impacts associated with the disposal of coal combustion solid waste products. 79 Fed. Reg. at 34,882. There is no reason why EPA should not factor the potential for heat rate improvements of natural gas-fired EGUs in setting the stringency of the standard, which would result in greater environmental benefits than currently estimated under Building Block 1.[116]

Even though EPA's proposal contemplates including both fossil fuel-fired units and stationary combustion turbines in a single category (codified under a new Subpart UUUU), failure to include oil- and gas-fired ("O&G") steam EGUs and NGCCs under Building Block 1 implies that these EGUs are not subject to emission reduction requirements. Section 111(d) requires state plans to include "standards of performance for any existing source," and thus, EPA's BSER determination is *for the affected sources*—coal-fired, oil-fired, and natural gas-fired units alike. We urge EPA to incorporate oil- and natural gas-fired units to Building Block 1, and to reformulate its BSER approaches accordingly.

Under EPA's second BSER approach, the BSER would include, first, Building Block 1—heat rate improvements (and other capital investments such as turbine blade replacements) on affected coal- and O&G-fired steam EGUs, NGCCs, and CTs, and second, a reduced utilization component. The reduced utilization component would comprise limiting the dispatch of fossil fuel-fired steam EGUs by the amount of available existing NGCC and CT capacity in 2020, and thereafter limiting the dispatch of fossil fuel-fired EGUs (steam EGUs, NGCCs, and CTs) by the amount of available renewable energy and energy efficiency.

In the sections that follow, we establish that each of EPA's proposed BSER building blocks, if strengthened in the ways that we suggest, are adequately demonstrated and will not impose unreasonable costs on the U.S. electric power generation industry. We note, however, that EPA is not proposing that each of the measures in its proposed system of emission reductions be met. Instead, EPA proposes a formula that identifies one low cost mix of

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[115] See Sierra Club, et al., *Comments on Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0495-9514 (May 9, 2014), attached as **Ex. 7**, at 55.

measures that can achieve significant emission reductions and proposes to allow sources, states and groups of states flexibility in achieving equivalent reductions. It is this system—an objectively determined formula that sets broad goals, coupled with a mechanism to allow states working with sources in their state to devise the most reasonable means of meeting those broad goals—that must meet the statutory tests described above.

IV. Severability

The proposed rule expressly states EPA's intent that the various building blocks that constitute the BSER be severable, so that in the event that a court were to invalidate the agency's finding with respect to any particular building block, EPA would find that the BSER consists of the remaining building blocks. EPA proposes that the state goals that would result from the combination of the remaining building blocks would be computed from the data included in the Goal Computation TSD and its appendices, using the computation methodology described in the preamble and that TSD. 79 Fed. Reg. at 34,892. This proposed approach is sound, and consistent with the case law on severability discussed below.

A. EPA's Expressed Intent to Make the Building Blocks Severable is Sound.

Agency intent is the touchstone of an inquiry into whether a regulation or other agency action is severable. *See, e.g.*, *Davis Cnty. Solid Waste Mgmt. v. EPA*, 108 F.3d 1454, 1459 (D.C. Cir. 1997)*; North Carolina v. FERC*, 730 F.2d 790, 795–96 (D.C. Cir. 1984); *Iowa Utils. Bd. v. F.C.C.*, 120 F.3d 753, 819 (8th Cir. 1997), *as amended on reh'g (Oct. 14, 1997), aff'd in part, rev'd in part sub nom. AT & T Corp. v. Iowa Utilities Bd.*, 525 U.S. 366 (1999). In *Davis*, operators of existing municipal waste combustor ("MWC") units which had municipal solid waste ("MSW") capacities below 250 tons/day, but which were located at a plant with an aggregate MSW capacity above 250 tons/day, challenged EPA's 1995 standards under Sections 111 and 129 of the Clean Air Act. 108 F.3d at 1455. In its initial opinion, the D.C. Circuit vacated the 1995 standards in their entirety; however, on EPA's petition for rehearing on the remedy, the Court held that the standards would be vacated only as applied to small MWC units and cement kilns, leaving the performance standards and emission guideline for large units other than cement kilns in place. *Id*. at 1455, 1460.

In amending its prior ruling, the Court inquired whether EPA intended the regulation at issue to be severable, and whether there was "substantial doubt" that EPA would have adopted the severed portion on its own. The Court found that EPA intended the regulation to be severable, because it was "clear that the EPA would have adopted the standards for large MWC units even without the standards for small MWC units and cement kilns." *Id*. at 1459. The Court noted that "[t]he 1995 standards for large and small MWC units [were] not in any way 'intertwined,' [and that] they operate[d] entirely independently of one another." *Id*. at 1459 (quoting *Telephone & Data Sys. v. FCC*, 19 F.3d 42, 50 (D.C. Cir. 1994)); *see also Arizona Pub. Serv. Co. v. U.S. E.P.A.*, 562 F.3d 1116, 1122 (10th Cir. 2009) ("[a] regulation is severable if the severed parts operate entirely independently of one another, and the circumstances indicate the agency would have adopted the regulation even without the faulty provision.") The inclusion of a severability clause in a regulation creates a presumption that an invalid portion is severable. *High Country Conservation Advocates v. U.S. Forest Serv.*, No. 13-CV-01723-RBJ, 2014 WL 4470427 (D. Colo. Sept. 11, 2014).

In the Clean Power Plan, the proposed building blocks operate independently of one another. EPA has analyzed each building block individually, providing an assessment of technical potential, costs, and a description of data inputs used as the basis for the computation of the proposed state goals. 79 Fed. Reg. at 34,858-75. The proposal's technical support documents explain the rationale and derivation of these values.[117] EPA has also explained why each of the individual building blocks meets the statutory factors to qualify as components of the BSER under the agency's first BSER approach, and why each of the building blocks can serve as the basis for quantifying the amounts of reduced utilization from affected EGUs under its second BSER approach. *Id.* at 34,881-84.

In addition, in its proposed computation methodology, EPA has added each of the building blocks to the formula separately, calculating the 2012 emission rate for covered sources, and then adjusting the formula to reflect the application of each building block: first, adjusting the coal emission rate to reflect a six percent heat rate improvement; second, increasing NGCCs' generation values up to a maximum of 70 percent, while decreasing generation values for coal and oil/gas-fired steam EGUs proportionately; third, adding estimated total generation from renewables and covered nuclear; and fourth, adding estimated total generation avoided from implementation of demand-side energy efficiency. The Goal Computation TSD annexes contain the state level data, calculations, and emission rates used to derive the interim and final goals, for both the main proposal (ending in 2030) and the alternative (ending in 2025). The proposal itself provides EPA's intent that the various building blocks be severable. *Id.* at 34,892.

B. The Clean Power Plan Meets the Requirements for Severability.

Where an agency intends the provisions of a rule to be severable, invalidation of one provision does not warrant invalidation of the entire rule as long as the remaining provisions can operate sensibly without the stricken provision. *MD/DC/DE Broadcasters Ass'n v. F.C.C.*, 253 F.3d 732, 734 (D.C. Cir. 2001).

As noted above, EPA has expressly stated its intent that the regulation be severable. In addition, the rule can operate sensibly even if with the invalidation of one or more of the building blocks. The regulation can serve the goal of reducing carbon emissions from affected

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[117] EPA, *Goal Computation TSD*, Docket ID No. EPA-HQ-OAR-2013-0602 (June 2014), *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-goal-computation.pdf. EPA, *Technical Support Document: GHG Abatement Measures*, No. EPA-HQ-OAR-2013-0602 (June 10, 2014) (hereafter, "*Abatement Measures TSD*"), *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf,

EGUs without a stricken building block--each building block independently accomplishes some level of carbon dioxide reduction, and each can operate regardless of whether any of the others are in place. Because the goal computation formula is additive, EPA can easily recalculate the state goals to reflect any invalidation of one or more building blocks.

V. The Building Blocks

A. Building Block 1

1. Building Block 1 is Legally and Technically Justified as an Element of BSER.

There is little controversy that heat rate improvements ("HRI") at individual fossil-fired EGUs are legally permissible elements of a BSER determination. During the lead-up to EPA's Clean Power Plan, there has been and continues to be considerable debate over the extent to which EPA may include measures "outside-the-fence" of individual units when developing pollution control regulations under section 111(d), as opposed to "inside-the-fence" measures—those that can be implemented entirely within the engineering, design, or utilization of an individual unit. What nearly all parties—including utilities, industry groups, and EGU owners and operators—agree on is that EPA may include entirely inside-the-fence measures in a BSER formula. Heat rate improvements at individual EGUs, which are the basis for Building Block 1, are precisely such measures since they can be implemented on-site at each individual unit.

More specifically, the HRI that EPA has proposed for Block 1 meet the legal standards for a BSER determination under section 111. First, these measures are achievable and adequately demonstrated. EPA expects units to achieve the HRI under Block 1 through two well-demonstrated techniques: enhanced operation and maintenance practices and a number of specific equipment upgrades that have been identified in the technical literature and undertaken at plants around the world.[118] We discuss these methods in more detail below, and provide documentation showing that the HRI specified under Block 1 are not only achievable, but are overly conservative and must be strengthened. Furthermore, the operating and maintenance improvements and equipment upgrades that inform the Block 1 HRI will have no non-air quality environmental impacts, nor will they adversely affect the nation's energy requirements.

Finally, as EPA notes in its Abatement Measures TSD, the costs associated with the Block 1 HRI will not be exorbitant, particularly in light of the fact that the fuel savings associated with increased EGU efficiency will offset these costs in considerable part.[119] Our recommended improvements to Building Block 1 will not alter this picture dramatically. We demonstrate that units will be able to improve their heat rates by at least six percent (as opposed to EPA's predicted four percent) through operating and maintenance techniques, which are associated with very low costs. While equipment upgrades are more expensive than operating and

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[118] *Abatement Measures TSD* at 2-30 to 2-35.
[119] *Id.* at 2-36 to 2-40.

maintenance modifications, EPA's analysis shows that these costs are still well within the range of what is reasonable. We believe that the agency has overestimated the extent to which the nation's coal plants have already implemented some of these upgrades (in particular turbine blade replacements), so we expect that units can achieve a four percent (as opposed to two percent) HRI improvement through those measures. While this may yield marginally higher aggregate costs than EPA's predictions, they are nonetheless economically reasonable and will produce greater savings in conserved fuel.

For these reasons, HRI are a legally appropriate component of EPA's BSER determination. Below, we discuss in more detail how the agency can improve Building Block 1 to ensure greater emission reductions through HRI.

2. As Proposed, Building Block 1 Is Too Conservative and Must Be Strengthened.

a. EPA's Statistical Analysis of the Performance of Existing Units Demonstrates that a Heat Rate Improvement From Better Operation and Maintenance (O&M) of Existing Units in Excess of 6 Percent Is "Adequately Demonstrated."

In determining the appropriate target under Building Block 1, EPA first examined the level of emission reductions that has been demonstrated at existing units, then determined the additional reductions that have been demonstrated to be achievable from plant upgrades.[120] In quantifying the O&M component of Block 1, EPA reasonably considered the level of performance that each unit has demonstrated in the past. The agency first looked at the hourly average heat rate for essentially all (96 percent) of the units in the system between 2002 and 2012, correcting for differences in heat rate that could be correlated to temperature and load. EPA then calculated what would happen to the average heat rate at each unit if the heat rate at every given hour were reduced by a specified percentage of the difference between the heat rate for that hour and the average heat rate for the top 10 percent of all hours for that unit. EPA reports that a fleet wide improvement of 1.3 percent would result if units, on average, reduced their heat rate by 10 percent of the difference between the average and top decile heat rates and that reducing heat rates by 50 percent of that difference would produce a 6.7 percent improvement fleetwide.

EPA acknowledges that its selection of 30 percent of the difference between the average and top decile heat rates (resulting in a 4 percent heat-rate improvement fleet wide) is conservative, justifying its selection with the observation that it is in the middle of the range (10 to 50 percent) that EPA chose to analyze. Notably, EPA does not justify its choice of a range to analyze. Had the agency chosen to analyze a range of 30 to 70 percent, for instance, the mid-point of its chosen range would be 50 percent. EPA acknowledges that a 50 percent reduction in the difference between the fleet's average and top decile rates would yield a 6 percent heat rate improvement fleet-wide. The agency rationalizes its decision to select a lower figure of 30

[120] The discussion in this paragraph and the two that follow references 79 Fed. Reg. at 34,860-61 and EPA's *Abatement Measures TSD* at 2-30 to 2-35.

percent by analogizing to a standard based on a three-year rolling average rather than a rolling annual average. EPA notes that plants would achieve a 6.7 percent heat-rate improvement if they were to meet their top rolling annual average over the 11-year study period and a 3.9 percent improvement if they were to meet their best rolling three-year average. These numbers correspond fairly closely to the 6 and 4 percent improvements that would result from 50 and 30 percent reductions (respectively) in the difference between the annual and top decile heat rates. EPA then states that a hypothetical selection of the three-year rolling average would be more appropriate than a rolling annual average due to potential differences in weather and load; hence, it avers that a 30 percent reduction between the average and top decile heat rates (analogous to a three-year rolling average) is a superior target than a 50 percent reduction (analogous to a rolling annual average).

EPA's reasoning here is flawed. As noted above, EPA already controls its data pool for temperature and capacity factor. To select a more lenient standard in order to smooth out difference in weather and load is, in effect, double controlling for these variables, and is a methodological error. Furthermore, in actuality, differences in temperature profiles and loads from one year to the next are relatively small and are not large enough to justify the EPA accommodation. EPA's analogy to annual vs. three-year rolling averages is inappropriate, and the agency has not justified its decision to select a 30 percent rather than 50 percent reduction between the average and top decile heat rates as the basis for its calculations. The agency correctly focuses on annual averages. Here, too, differences in annual temperature profiles and load are relatively small and are not large enough to justify the EPA accommodation. Accordingly, each of EPA's analyses demonstrates that a 6 percent fleet-wide improvement is achievable and that its choice of 4 percent is overly conservative.

b. The Sierra Club's 52-Unit Study Independently Confirms that a Heat Rate Improvement of Six Percent From Better O&M at Existing Units Is "Adequately Demonstrated."

In order to analyze the true extent of the heat rate improvements available through operation and maintenance practices, the Sierra Club conducted a preliminary review of the detailed operating records for individual coal-fired EGUs maintained in EPA's Air Markets Program Database ("AMPD").[121] The AMPD data revealed a number of occasions where there was a significant and sudden unexplained change in plant operating efficiency that did not appear to be related to boiler load or a gradual degradation of performance with age.[122] Accordingly, the Sierra Club conducted additional comprehensive research—"the 52-Unit Study"—to determine whether the initially observed characteristics are common throughout the coal-fired fleet and to quantify the adverse impact on GHG emissions associated with the observed efficiency variances.

[121] *See* EPA, Air Markets Program Data, www.ampd.epa.gov (last visited Nov. 28, 2014).
[122] These data are attached as **Appendix 1**, which we are delivering to EPA separately in a flash drive.

In the 52-Unit Study, the Sierra Club examined the long term variability in the performance of a representative number of randomly selected coal-fired power plants. In order to assure that the selected plants provided an accurate representation of the generation of electricity by the coal-fired EGU population as a whole (which would not be the case if focused on a large number of lightly used or smaller plants), the 52 Unit Study first grouped each plant into a specific "bin" based on its generation in 2012 as reported to EPA's AMPD. [123] It then identified a proportionate number of randomly selected plants within each generation bin for further study. Selection was based on applying the standard random number generator in Microsoft Excel to each bin of units. Additional "standby" candidates were initially identified in each bin in case some of the initially identified candidates were excluded from the study.[124] The study did not attempt to ensure that units of different designs (such as stoker, wall-fired, or circulating fluidized bed units) were equally represented in the sample pool, but information about each unit's design, age, installed pollution controls and capacity factor were captured for use in further analysis. We note that the average capacity of units in the study was 597MW and the average capacity factor for those units was 0.61. Table 1 provides a profile of each of the six generation bins in the study.

Table 1: Bins for Selection of Units

Annual Unit Generation	Number of Units	Total Generation (MMWh/yr)	Number in Study
0.1- 1 million MWh	361	174	6
1-2 million MWh	125	179	6
2-3 million MWh	102	253	9
3-4 million MWh	114	395	14
4-5 million MWh	50	221	8
5-9million MWh	42	253	9

For each selected unit, the study captured daily average performance data between January 1, 2001 and December 31, 2012 for heat rate, generation, CO_2 emission rate, fuel consumption, and criteria pollutant emissions, as well as facility data such as the date of first commercial operation, maximum capacity, and installed pollution controls. The data permit a reasonably objective determination of the temporal variation in carbon emission rate (CO_2/MWh) at subject plants. The study reports rolling annual averages[125] of the daily average emission rates in order to minimize the effect of weather and load, to represent long-term trends, and to reflect the likelihood that EPA's guidelines will be based on annual average

[123] AMPD data are presented on a gross electric output basis and so do not include the additional variability that might be associated with the operation of pollution control devices.
[124] Three units were excluded from the study because emission and generation data for the full study period was not available. Replacements were selected from the same bin employing the random numbers initially generated for that bin.
[125] To calculate a unit's rolling annual average, we calculate its average daily emission performance over each consecutive period of 365 operating days for the interval of the study.

emissions. To illustrate data from one facility in the study, Figure 2 depicts the daily average emission rate at Cross Unit One during the 12-year study interval.

Fig. 2- Cross Unit One Daily Average Emission Rate, 2001-2012

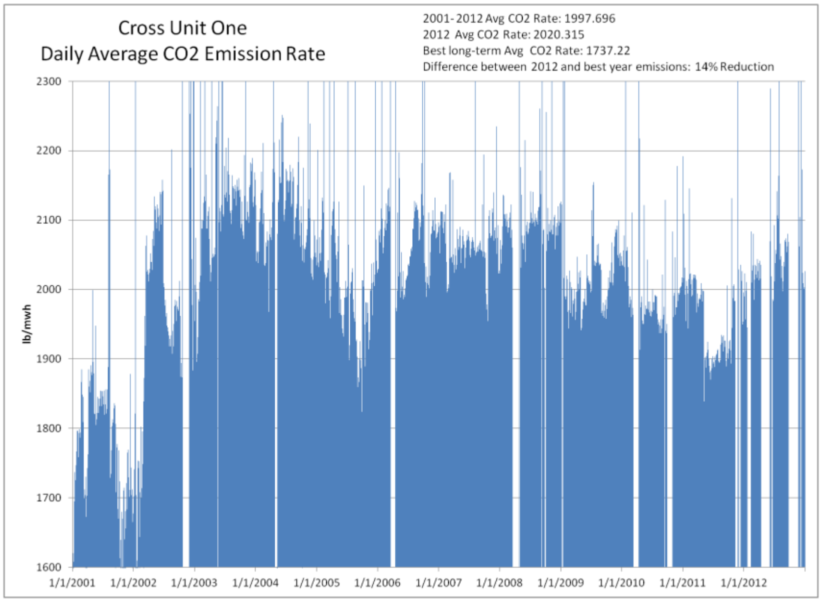


Table 2: Results of the 52-Unit Study

State	Plant Name	2001-2012 Lowest Rolling Annual Average	95th Percentile Lowest Rolling Annual Average	2001-2012 Aver age	Percent Improvement-Lowest Rolling Annual Average	Percent Improvement-95th Percentile Lowest Rolling Annual Average	Nameplate Capacity (MW)
AR	White Bluff	2026	2049	2175	6.85%	5.79%	900.0
CO	Rawhide	1869	1877	2067	9.58%	9.19%	293.6
CO	Craig	1919	1927	1982	3.18%	2.77%	534.8
FL	Crystal River	1981	2004	2100	5.67%	4.57%	739.2
IA	George Neal North	1943	1968	2044	4.94%	3.72%	549.8
IA	Ottumwa	2118	2147	2322	8.79%	7.54%	725.9
IL	E D Edwards	2006	2088	2199	8.78%	5.05%	136.0
IN	F B Culley	1880	1916	2214	15.09%	13.46%	265.2
IN	Cayuga	1736	1747	1878	7.56%	6.98%	531.0
IN	Merom	1936	1961	2070	6.47%	5.27%	540.0
IN	Gibson	1726	1736	1817	5.01%	4.46%	667.9
KY	H L Spurlock	1732	1779	1894	8.55%	6.07%	357.6
KY	Mill Creek	1654	1676	1794	7.80%	6.58%	355.5

KY	Ghent	1840	1849	1934	4.86%	4.40%	556.5
LA	Big Cajun 2	1956	1961	2126	8.00%	7.76%	619.0
MI	Dan E Karn	1976	1989	2043	3.28%	2.64%	136.0
MO	Rush Island	1705	1845	1910	10.73%	3.40%	621.0
MO	Iatan	1940	1949	2152	9.85%	9.43%	726.0
MT	Colstrip	2092	2140	2279	8.21%	6.10%	358.0
Navajo	Four Corners	1752	1773	1862	5.91%	4.78%	818.1
NC	Belews Creek	1677	1688	1765	4.99%	4.36%	1080.1
ND	Milton R Young	2105	2126	2244	6.19%	5.26%	477.0
NE	Sheldon	2091	2141	2323	9.99%	7.83%	108.8
NE	Nebraska City	1911	1926	1982	3.58%	2.83%	651.6
NY	Somerset Operating	1740	1759	1845	5.69%	4.66%	655.1
OH	Muskingum River	1835	1840	1887	2.76%	2.49%	237.5
OH	FirstEnergy W H Sammis	1723	1733	1854	7.07%	6.53%	190.4
OH	Walter C Beckjord	1763	1770	1945	9.36%	9.00%	244.8
OH	J M Stuart	1773	1777	1919	7.61%	7.40%	610.2
OH	Cardinal	1741	1758	1831	4.92%	3.99%	615.2
OH	Miami Fort	1585	1650	1894	16.31%	12.88%	557.1
PA	PPL Brunner Island	1538	1548	1641	6.28%	5.67%	405.0
PA	Hatfields Ferry Power Station	1716	1794	1941	11.59%	7.57%	576.0
PA	Keystone	1733	1740	1811	4.31%	3.92%	936.0
PA	Keystone	1803	1809	1842	2.12%	1.79%	936.0
PA	Conemaugh	1682	1707	1802	6.66%	5.27%	936.0
PA	FirstEnergy Bruce Mansfield	1659	1687	1811	8.39%	6.85%	913.7
SC	Cross	1737	1826	1998	13.06%	8.61%	590.9
TN	Cumberland	1784	1815	1941	8.09%	6.49%	1300.0
TX	Harrington	1810	1849	2190	17.35%	15.57%	360.0
TX	Fayette Power Project	1920	1937	2016	4.76%	3.92%	615.0

TX	W A Parish	1877	1891	2015	6.85%	6.15%	734.1
TX	Martin Lake	2092	2113	2183	4.17%	3.21%	793.2
TX	J K Spruce	1921	1980	2157	10.94%	8.21%	878.0
VA	Clinch River	1660	1692	1803	7.93%	6.16%	237.5
WV	Mt Storm	1945	1954	2052	5.21%	4.78%	570.2
WV	John E Amos	1773	1782	1879	5.64%	5.16%	1300.0
WY	Jim Bridger	1956	2001	2119	7.69%	5.57%	577.9
WY	Laramie River Station	2107	2153	2265	6.98%	4.94%	570.0
AR	Independence Unit One	2050	2058	2121	3.35%	2.97%	900.0
IL	Powerton Unit Six	1871	1923	2182	14.25%	11.87%	892.8
IL	Joppa Unit Two	1866	2040	2116	11.81%	3.59%	183.3
	AVERAGE	1,851	1,882	2,005	7.60%	6.07%	597

We note that EPA proposes a single HRI target to be applied, on average, to all remaining coal-fired units in a state and then allows the state to determine whether to apply the HRI targets at all. This approach provides more than enough flexibility to rebut any industry argument that individual units might not be able to meet a single proposed HRI target. Moreover, EPA need not set a standard that every unit can achieve. To the extent that EPA declines to set the standard based on the lowest rolling annual average, however, EPA could set the HRI based on a calculation of the 95th percentile of the lowest rolling annual average emission rate (instead of the lowest rolling annual average emission rate) for each of the affected EGUs in a given state over a long term (such as 2001-2012) and an additional four percent reduction of that rate to reflect the improvements to be expected from the hardware upgrades we discuss below. This emission rate, multiplied by the generation from each unit in the year that the target rate is calculated, would determine the weighted average emission rate that is the Block 1 heat rate improvement for the state.[126]

In the 52-Unit Study, the Sierra Club also examined the extent to which the fleet's daily average emission performance varied with respect to load over the 12-year interval. At some units, (such as Powerton Unit 61, as shown in Figs. 3 and 4), there were very large differences in emission rates at the same daily load and, indeed, over all load ranges.

[126] As we discuss below, we recommend that EPA base its goal calculations on generation data from the year immediately prior to each state's submission of its final, approvable plan.

Fig. 3- Powerton Unit 61 Daily Average Emission Rate, 2001-2012

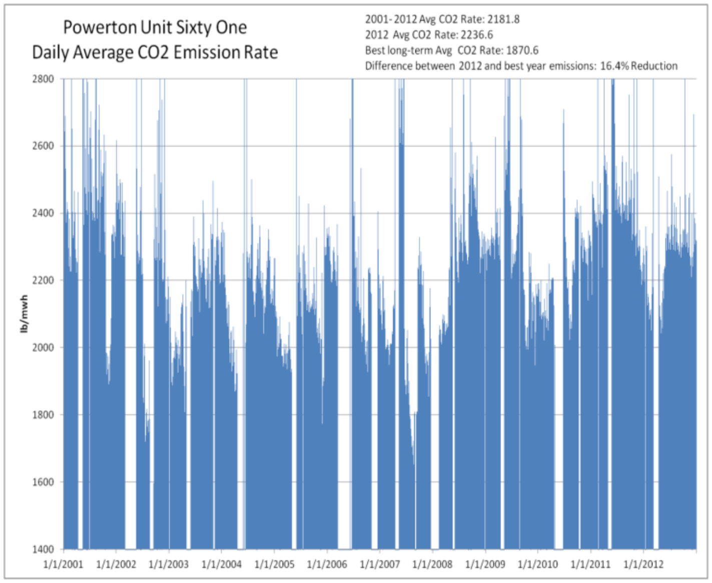
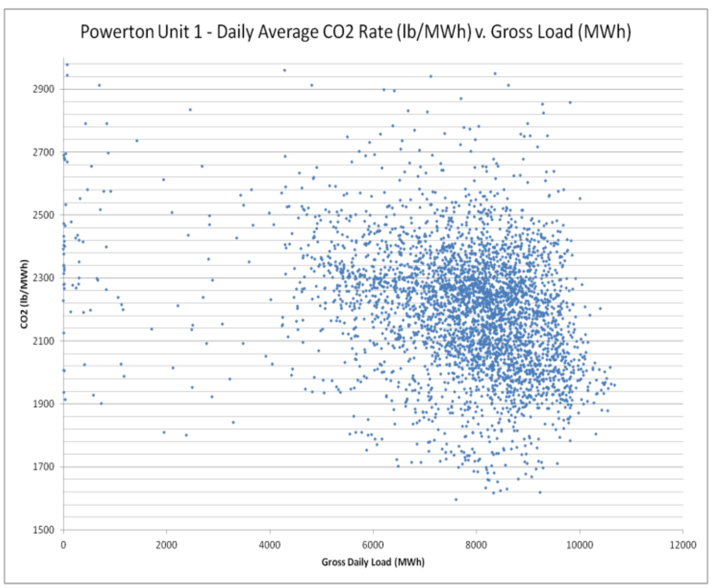


Fig. 4- Powerton Unit 61 Daily Average Emission Rate vs. Gross Daily Load, 2001-2012[127]



At other units, including Joppa Steam Unit Two (see Figs. 5 and 6 below), variation in emission performance over most load ranges was far smaller. Detailed plots for each unit in the study are presented in Appendix 1. These data support a conclusion that factors other than load are responsible for significant variation in the reported efficiency of many existing coal-fired EGUs.

[127] In these figures each marker represents the load and emission rate for a single day.

Fig. 5- Joppa Steam Unit Two Daily Average Emission Rate, 2001-2012

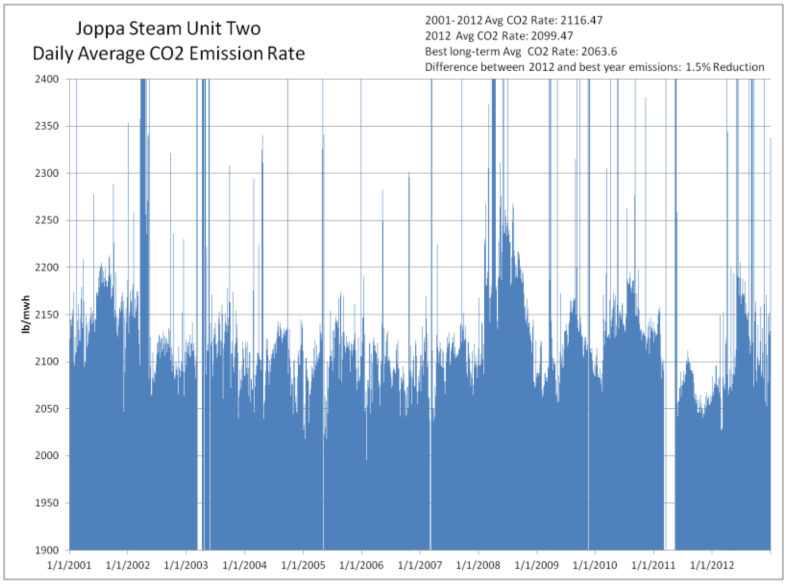


Fig. 6- Joppa Steam Unit Two Daily Average Emission Rate vs. Gross Daily Load, 2001-2012

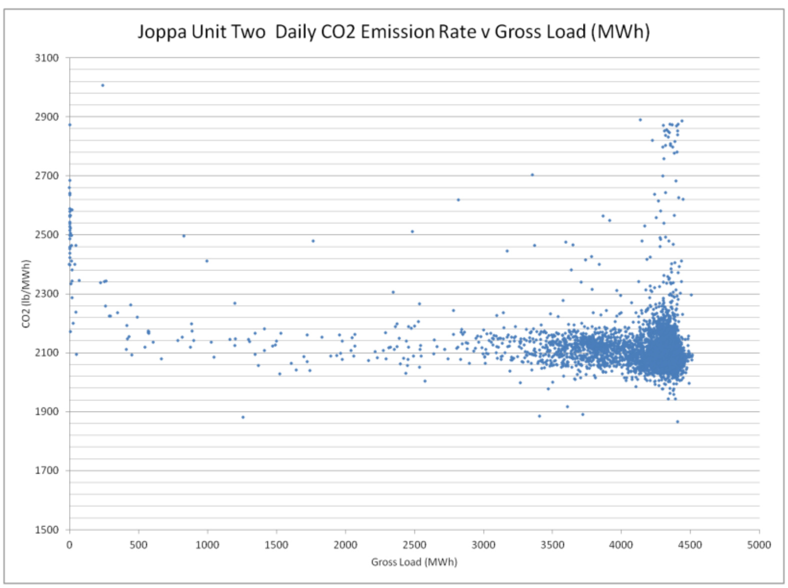
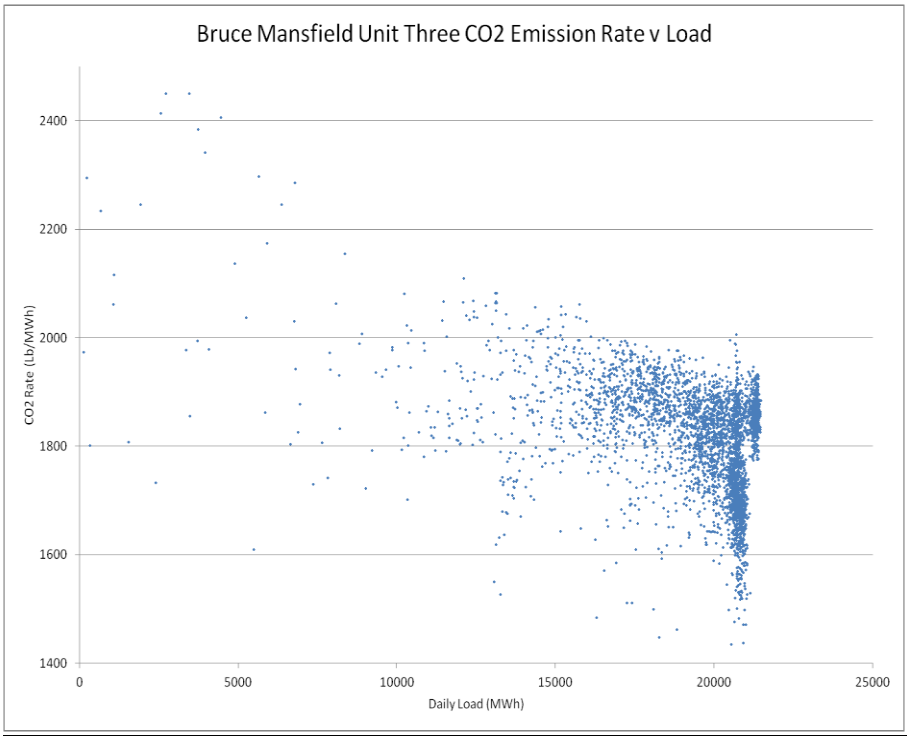


Fig. 7- Bruce Mansfield Unit Three CO_2 Emission Rate v Load 2001-2012



Here, it may be observed that the Bruce Mansfield emission rates trend up at lower load as one would expect. But what is notable is the fact that at and near full load, where this plant normally operates, the daily emission rate varies from less than 1,500 lbs CO_2/MWh to 2,000 lbs CO_2/MWh. If load, weather and the laws of physics are not the controlling factors, the question naturally arises as to whether the observed variances may be reasonably be inferred to be due to differences in O&M cycles and practices. We believe that these factors are most likely the cause of the variances and that EPA is justified in making such an inference in the absence of compelling information to the contrary. These variances are different from the consistent, systematic improvements in efficiency that one might expect from installation of combustion optimization tools or equipment upgrades. Since the study population is randomly selected and biased toward units that produce the most generation[128] (and presumably are maintained better than units that are dispatched less frequently), a conservative estimate for the average expected plant improvement through better operation and maintenance of existing equipment is six percent. Under the relevant case law the standard does not have to be achievable by every single source.

The results of the 52-Unit Study (provided in Table 2 above) demonstrate that, on average, plants have achieved and maintained for a year an emission rate that is 7.60 percent better than their long term (12-year) average. The difference between the 95th percentile figure

[128] The study population included only six of 361 units (1.7 percent) that generated between 0.1 and 1 million MWh/yr, but 9 of the 42 units (21 percent) that generated more than 5 million MWh/yr.

and the long-term average is 6.07 percent. The use of rolling annual averages minimizes any short term efficiency variations based on weather, load, or equipment upgrades. Because there are differences in the year-over-year variation experienced at different units, broadly applicable factors, such as basic principles of thermodynamics or weather do not appear to be dominant, since such factors would create similar variation across all units. The Load v. Rate plots in the 52-Unit Study reveal a large difference in emission rates even at or near full load.

The several analyses by EPA and the National Energy Technology Laboratory ("NETL") and the Sierra Club 52-Unit Study each confirm that the O&M component of Block 1 should not be less than a 6 percent improvement over the long term average for the source.

c. The Record Adequately Demonstrates That Plant Upgrades Can Reduce Emission Rates by an Additional Four Percent.

In evaluating the equipment upgrades expected under Building Block 1, EPA provides an extensive literature review and discusses the leading technical analysis by the NETL[129] and other relevant documents.[130] Based on its review, the agency selected four specific technologies on which to base the Block 1 heat-rate improvements: economizer replacements, acid dew point controls, variable frequency drives for use with fans, and turbine blade overhauls.[131] In addition, the technical literature identifies the following upgrades for existing coal-fired EGUs that EPA does not include in its Block 1 calculations: condenser cleaning, intelligent soot blowers, electrostatic precipitator modifications, boiler feed pump rebuilds, air heater and duct leakage controls, neural networks, modifications of criteria pollutant control systems (selective catalytic reduction equipment and flue-gas desulfurization configurations), and advanced packing at cooling towers.[132]

Describing the four equipment upgrades underscoring its Block 1 methodology, EPA concludes that

> [t]he remaining four methods are higher cost heat rate improvement items that we believe properly fall into the category discussed here as upgrades. Using an average of the ranges of potential Btu improvements estimated by Sargent &

[129] *See, e.g.*, Dep't of Energy ("DOE")/NETL, *Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States*, DOE/NETL Technical Workshop Report (Feb. 24-25, 2010), attached as **Ex. 8**; NETL, Office of Systems, Analyses and Planning, *Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions*, DOE/NETL-2010/1411 (Apr. 16, 2010), attached as **Ex. 9**; See Phillips & Levine, Fern Engineering, Gas Turbine Performance Upgrade Options, *available at* http://www.fernengineering.com/pdf/gt_upgrade_options.pdf; Ginter & Bouvay, GE Energy, Uprate Options for the MS7001 Heavy Duty Gas Turbine (2006), *available at* http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger3808c_r31.pdf.

[130] We have reviewed and summarized a number of published reports that address these issues. *See* **Appendix 2**.

[131] *Abatement Measures TSD* at 2-33, 2-35.

[132] *Id.*

> Lundy for the four upgrade methods, upgrades, as defined here, could provide a 4% heat rate improvement if all were applied on an EGU that has not already made these upgrades. . . . The equipment upgrades results are supported by numerous studies and by the EPA's analysis of the costs and associated improvements in heat rate that can be attributed to equipment and system upgrades.[133]

EPA declines to adopt a four percent reduction in heat rate because of uncertainty as to the extent to which these technologies have been adopted while acknowledging that this approach is conservative:

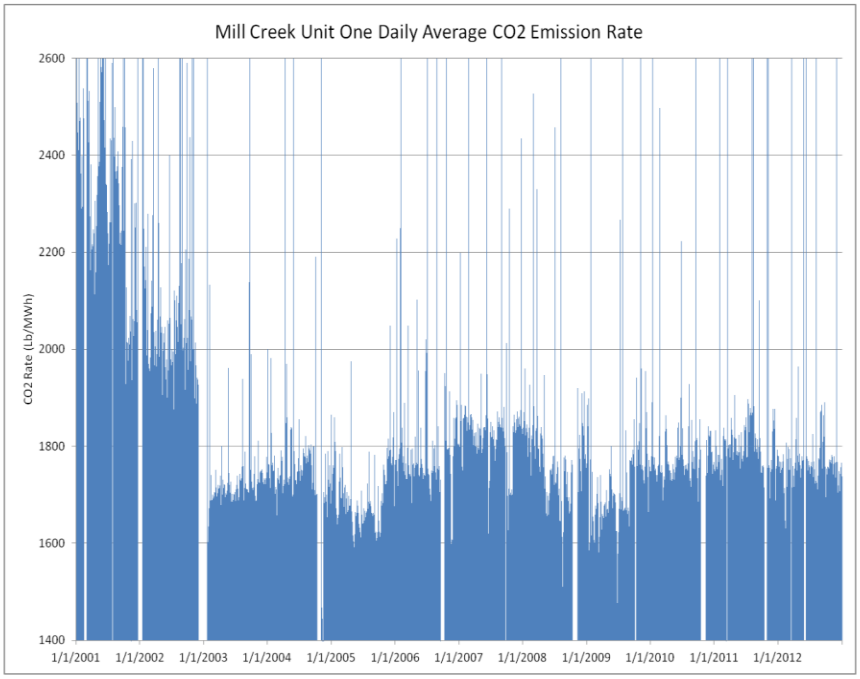
> We considered that a 4% reduction in heat rate might be achieved on a coal-steam unit by applying the four higher cost upgrade actions described in Table 2-13 above. However, because details of current actual unit configurations are unknown, and some units may have applied at least some of the upgrades, we conservatively estimate the heat rate improvement potential for upgrades at 2%.[134]

EPA need not—and, indeed, may not—vary from its technically sound determination that an additional four percent heat rate reduction is demonstrated through equipment upgrades, especially where it can either directly determine or infer from existing data the extent to which these techniques have been employed in the industry. The agency still has time to issue an information request under section 114 of the CAA to the five or six largest operators of coal-fired power plants if comprehensive information is not provided in their comments. [135]

Several of the most effective upgrades, such as turbine upgrades,[136] can only be performed during extended outages and may require either major or minor CAA permitting. EPA can by itself determine the number of permits (if any) that have been issued for such projects. Additionally, it is likely that the long-term emission profile of a unit undergoing such an upgrade would show a significant emission rate reduction immediately following an extended outage and that this improvement would be sustained for several years. Notably, the emission profiles of only a small percentage of the plants in the 52-Unit Study demonstrate this characteristic. Some units, such as Mill Creek Unit One, do show the emission profile that one would expect following a significant upgrade.

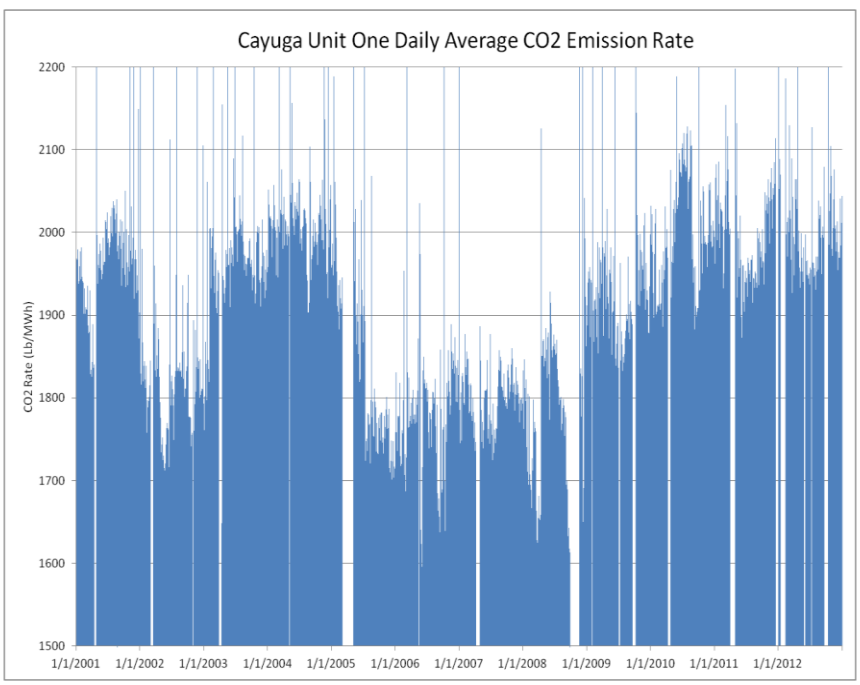
[133] *Id*.
[134] *Id.*
[135] By limiting the request to fewer than nine persons, delays associated with the Paperwork Reduction Act may be avoided. 44 U.S.C. § 3502(3)(a)(i) (statute applies to information requests submitted to "ten or more persons").
[136] Upgrading with advanced components is an entirely different technology than a "refurbishment" of existing equipment that might occur every 10 years.

Fig. 8- Mill Creek Unit One Daily Average CO_2 Emission Rate 2001-2012



Other units, such as Cayuga Unit One, show a significant improvement that is not sustained over the long term, suggesting that whatever upgrade led to the improvement needs to be renewed or maintained.

Fig. 9- Cayuga Unit One Daily Average CO_2 Emission Rate 2001-2012



The data suggest that only four of the 52 units demonstrate a significant, sustained long-term improvement in CO_2 emission rates, such that one might conclude that they had undergone capital upgrades that yielded a sustained and substantial improvement in performance.[137] This indicates both that operation and maintenance practices alone (rather than equipment upgrades) can account for the six percent emission reduction indicated by the 52-Unit Study and that such upgrades have not been undertaken at most plants. While a number of facilities completed turbine blade replacement projects approximately 15 years ago, those units may well be due for additional upgrading after 20 years, in line with the compliance schedule for the Clean Power Plan.

Moreover, published reports by industry demonstrate the relative infrequency of these types of projects to date. Siemens asserts that over the past 20 years, it and companies that it has acquired—Westinghouse and Parsons Steam Turbine—have upgraded turbines at 214 units comprising 88 GW of capacity worldwide.[138] Siemens also asserts that GE and Alstom have upgraded only two turbines each and MHI only two turbines worldwide.[139] However, information in other documents suggests that GE and Alstom may have upgraded 30 or 40 units each.[140] While Siemens may not be correct in its determination of the number of turbines upgraded by its competition, it can be presumed that Siemens knows how many turbines it has upgraded between 1992 and 2012. This information supports a conclusion that turbine upgrades to achieve efficiency improvements are not common worldwide or in the United States.

We recognize that some plant operators may object that an incremental emission reduction of four percent based on equipment upgrades overestimates what the fleet is actually capable of achieving. We urge the agency to reject this argument. As our study indicates, few plants have actually invested in the equipment upgrades that Building Block 1 contemplates, and a four percent heat rate improvement from such upgrades is entirely reasonable. While no company is obliged to comment on an EPA proposal, where an operator or trade association submits a comment and makes a generalized assertion but fails to provide specific information that can be presumed to be in its possession, EPA may take note of the omission.

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[137] Mill Creek One, Big Cajun Unit Three, Harrington Unit One and Rawhide Unit One appear to demonstrate the expected emission profile.
[138] Strunk & Kundu, Siemens, *Renovation, Modernization and Life Time Extension Measures on Steam Turbines*, presentation delivered at Power-Gen India & Central Asia 2012 (Apr. 2012), attached as **Ex. 10**, at 25.
[139] *Id.*
[140] *See, e.g.*, Lesiuk, J.F., GE Power Systems, *Steam Turbine Uprates, GER 4199* (Oct. 2000). This report asserts that at the time of publication there were over 40 GE turbines with advanced steam path design (the precursor to GE's Dense Pack system) in operation. While the article focuses on upgrades to existing turbines, it is not known how many of the 40 turbines cited are installed at new facilities, rather than as upgrades to existing turbines.

d. EPA Should Employ a Long-Term Baseline for Building Block 1 Rate-Setting and Compliance.

The emission data attached hereto as part of the 52-Unit Study demonstrate that selecting a single year's emission data to calculate the HRI expected under a rule can result in an unfair allocation to certain individual units. For some units, 2012 represented the best performance year over the past decade, while other units had relatively high emission rates in 2012. At least one state has commented that the unusual status of an individual unit in 2012 has a significant impact on its calculated BSER emission rate.[141] EPA has asked whether it should address this problem by permitting states or sources to choose 2010 or 2011 as a baseline year instead of 2012. This option is not an appropriate solution to the allocation problem. Any state or source that is allowed to choose its preferred baseline year will inevitably select the year that minimizes its own compliance obligation. This will invariably reduce the effectiveness of the standard, and, since it is unnecessary, will result in a rule that does not reflect the *best* system of emission reductions.

Our approach to Building Block 1 resolves the allocation problem without degrading the efficacy of the standard. As discussed above, EPA could calculate Building Block 1 emission reductions on the basis of the difference between a source's best rolling annual average rate and its long term (2001-2014) emission rate, as set out above and an additional four percent reduction based on available plant upgrades. This approach minimizes the impact of any particular year of operation and, since it is largely based on improved operation that has already been demonstrated by the source, is feasible. States can thereafter allocate compliance obligations among in-state sources to address any issues that might remain.

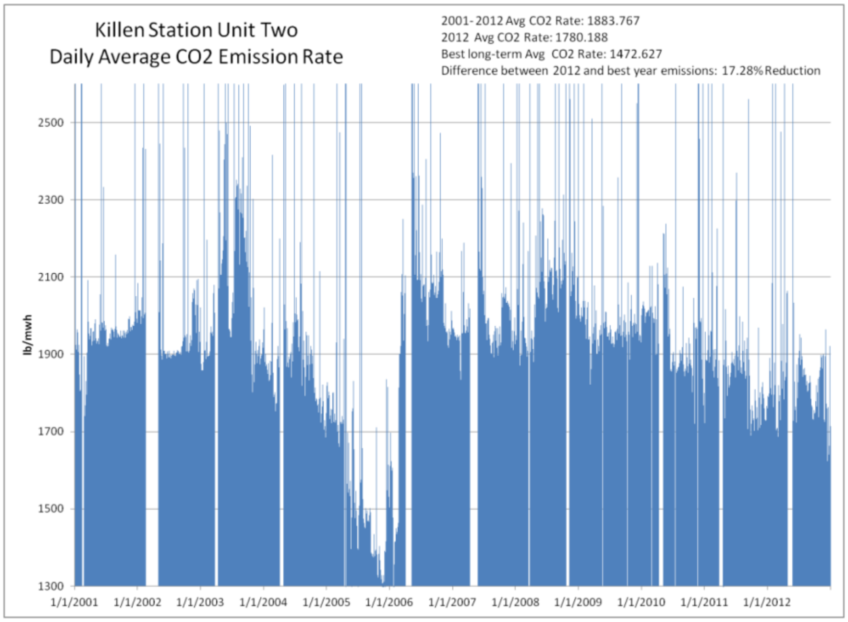
e. EPA Should Adopt a Far More Robust Compliance and Enforcement Scheme.

EPA has proposed to entirely abandon its traditional reliance on reference method testing. While we support continuous emission monitoring systems ("CEMS"), we note that the level of heat rate improvement (six to ten percent) assumed under Block 1 is not significantly larger than the calibration requirements for the continuous monitors. In addition, EPA's different data sets contain unexplained and, at times, technically incredible emission data reported by utilities. By way of example, the operators of Killen Station Unit Two[142] reported a gross CO_2 emission rate of less than 1,500 lbs CO_2/MWh for over a year in 2005-2006 (*see* Fig. 10 below), an emission rate that is neither technically possible for that type of facility nor sensible in light of the unit's performance in proximate years.

[141] *See Comments Submitted by John Line Stine, Commissioner, Minnesota Pollution Control Agency, On EPA's Proposed Guidelines for Greenhouse Gas Emissions from Existing Sources: Electric Utility Generating Units*, Dkt. No. EPA-HQ-OAR-2013-0602-17900 (Sept. 16, 2014), at 1.

[142] This unit was randomly selected for inclusion in the 50-Unit Study but was excluded from the calculations of the average improvement percentages because of this anomaly.

Fig. 10- Killen Station Unit Two Average Daily Emission Rate



In the past, EPA has permitted sources to rely on fuel sampling rather than CEMS data for compliance purposes. EPA should reject this option. First, fuel sampling is well known to be less accurate that CEMS data and will not serve as an adequate substitute. Second, under state programs adopted pursuant to the Clean Power Plan, emission data will be used to establish and enforce programs with a significant environmental impact and will form the basis of tradable emission credits. These data and the credits on which they are based will be far more valuable in the future than they are today. For this reason, EPA should work with states and sources in the coming years to clean up the existing data sets and tighten the technical installation requirements for CO_2 CEMS to ensure that accurate and unbiased data are produced.

It is our understanding that in the early years of the Acid Rain program, industry satisfied a substantial portion of its compliance obligation simply by "recalibrating" the existing monitoring equipment. EPA should adopt measures to ensure that the HRI anticipated under Building Block 1 are real and not illusory. This would include (1) reference method or other upgraded testing either as a relative accuracy test audit ("RATA") requirement or as a standalone test requirement; (2) identification of the specific measures undertaken to achieve and maintain the claimed heat rate improvement; and (3) correlation of the recalibrated result with the required improvement.[143]

EPA has proposed that sources should be able to choose from among several potentially available reference methods, but has solicited comment on whether EPA should require

[143] If it is determined that the monitor is reading at least three percent high (or low), a correction should be made both to the emission limitation that is based on that monitor and to the test result so that correcting the monitor error does not alter the source's compliance status.

operators to use the reference method that provides the most accurate results for the specific source.[144] The difference in cost between the available reference methods is quite small in the overall scheme and we are aware of no possible reason why EPA should permit a source to use any method that is less accurate than the published methods. Indeed, EPA should contemplate extending sampling times and volumes to improve accuracy over current Reference Method 2 variants.

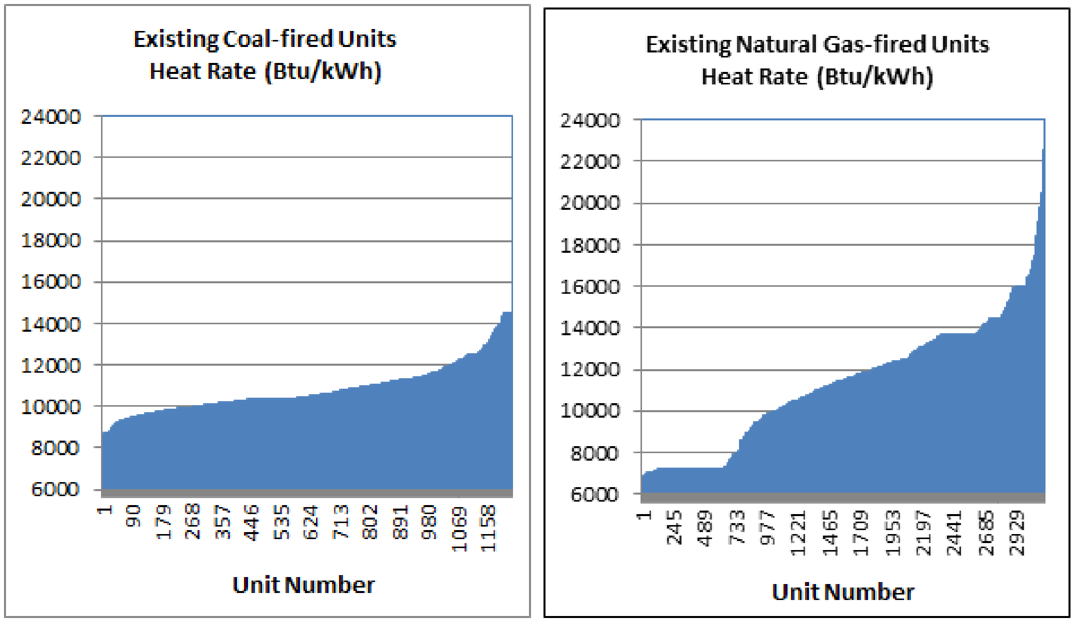
EPA has also asked whether electricity used during startup or when the unit is not producing electricity for the grid should be included in the determination of net electric output. EPA's regulations define operating day as any day in which fuel is being combusted,[145] so electric usage times when a unit is completely idled would not be included in the calculation, but electric usage by pumps, fans, and other components during startup, or for maintaining a unit at a hot or warm idle readiness state, are part of the normal process of generating electricity and should be included. Exempting this use of electricity unwisely promotes the use of plants designed for baseload operation in inefficient load-following service.

f. EPA Should Include Oil and Gas Steam Units in Building Block 1.

In its current proposal for Building Block 1, EPA assumes heat rate improvements will occur at coal-fired EGUs only. The agency has articulated no basis for excluding oil and gas ("O&G") steam units from Block 1's emission reductions, in spite of the fact that some of these units exhibit very high heat rates, as illustrated in Fig. 11 below. The data presented also shows that there is a greater disparity among heat rates at gas-fired steam units than among the coal-fired fleet.

[144] Often, the most accurate reference method depends on the shape of the stack at the point where the monitor is located.
[145] 40 C.F.R. § 60.41b.

Fig. 11- Heat Rates of Coal-Fired EGUs v. Natural Gas-Fired Steam EGUs



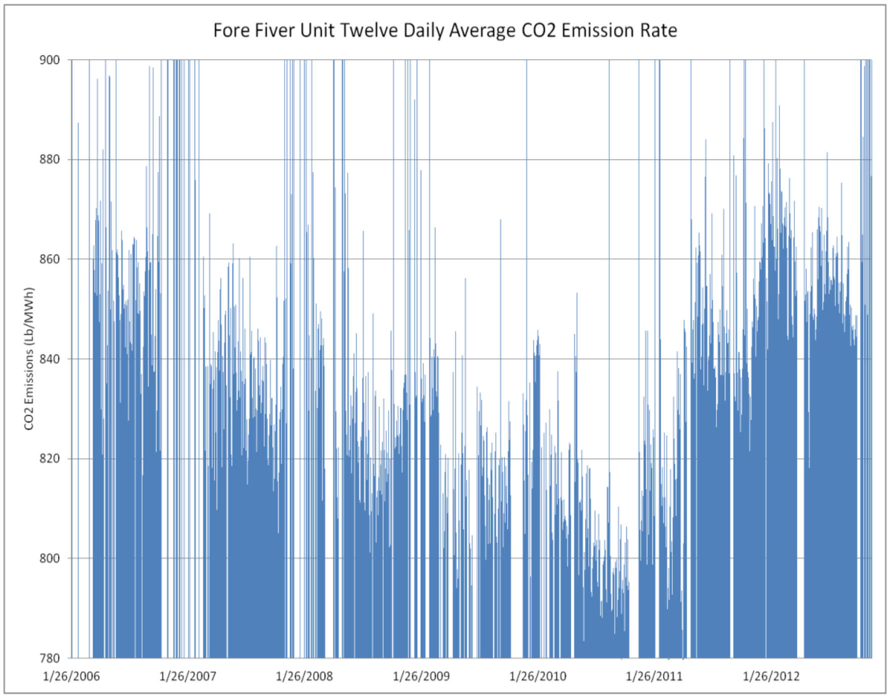
EPA has sufficient data to determine the difference between the best rolling annual average emission rate and the long-term average at each O&G steam unit. This would permit the same determination of an O&M-based heat rate improvement for those units as we have already proposed for coal-fired EGUs based on the 52-Unit Study. Furthermore, there is no reason to believe that plant upgrades, such as turbine blade replacements, would be any less effective at EGUs based on the differences in the fuel that generated the steam. Accordingly, any determination of BSER for the entire fleet of regulated EGUs must cover O&G steam units under Building Block 1.

g. EPA Should Determine the Amount of Emission Reductions from Existing NGCCs that Should Be Included in Building Block 1.

EPA has also excluded NGCCs from the goal-setting calculations under Block 1. Our review of EPA's AMPD data suggests that opportunities for O&M based reductions for much of the NGCC fleet that operates at approximately 850 lbs CO_2/MWh emission are smaller than for the coal-fired fleet. However, the potential for emission reductions may be significant. This issue deserves far more evaluation than EPA has thus far provided.

The emission profile of the Fore River Generating Station Unit Twelve, selected at random by the Sierra Club, provides an example of the potential performance improvements that might be anticipated were EPA to conduct a full evaluation. Other units have shown smaller variation. We have not compiled data reflecting the profile of the overall fleet.

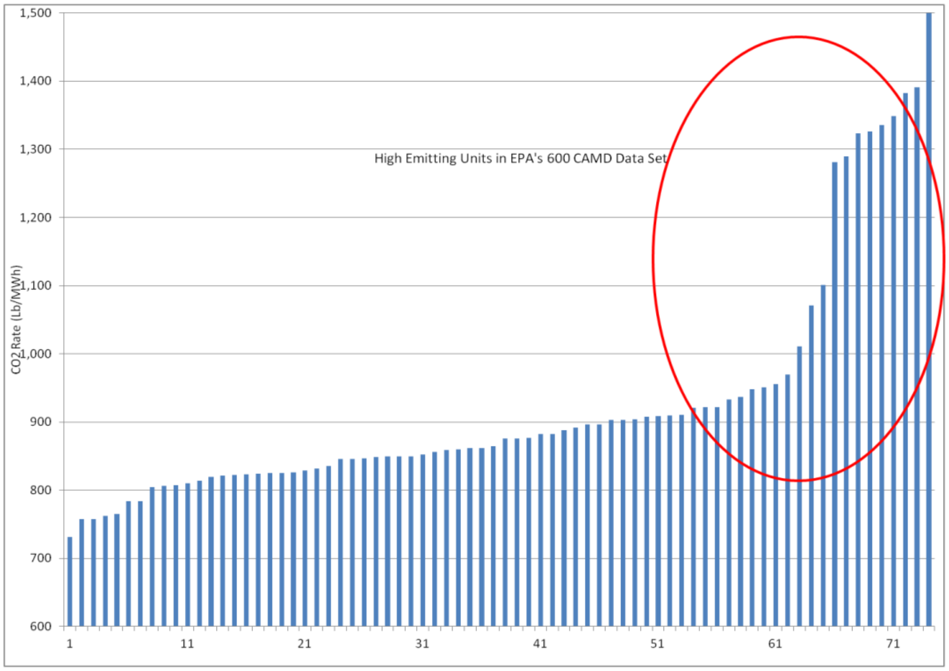
Fig. 12- Fore River Unit Twelve Daily Average Emission Rate 2006-2012



Fore River Unit 12's emission profile is similar to that of coal-fired units. The long term average performance of this unit was 831 Lb/MWh. It's best annual average performance was 3.4 percent better at 803 Lb/MWh and its 95th percentile rolling annual average was 805 Lb/MWh, 3.2 percent better than it's long term average. This unit's 2012 emission rate of 855 Lb/MWh is 6.7 percent higher than its 95th percentile low rolling annual average.

In addition to variation in performance of "better" units, the NGCC population includes a number of very high emitting units that deserve additional scrutiny. The following chart is taken from EPA's selection of "new NGCCs". It is provided to illustrate the difference in performance of "better" units, shown above, and high emitting NGCCs not yet evaluated by EPA.

Fig. 13- EPA's "600 CAMD Data Set"

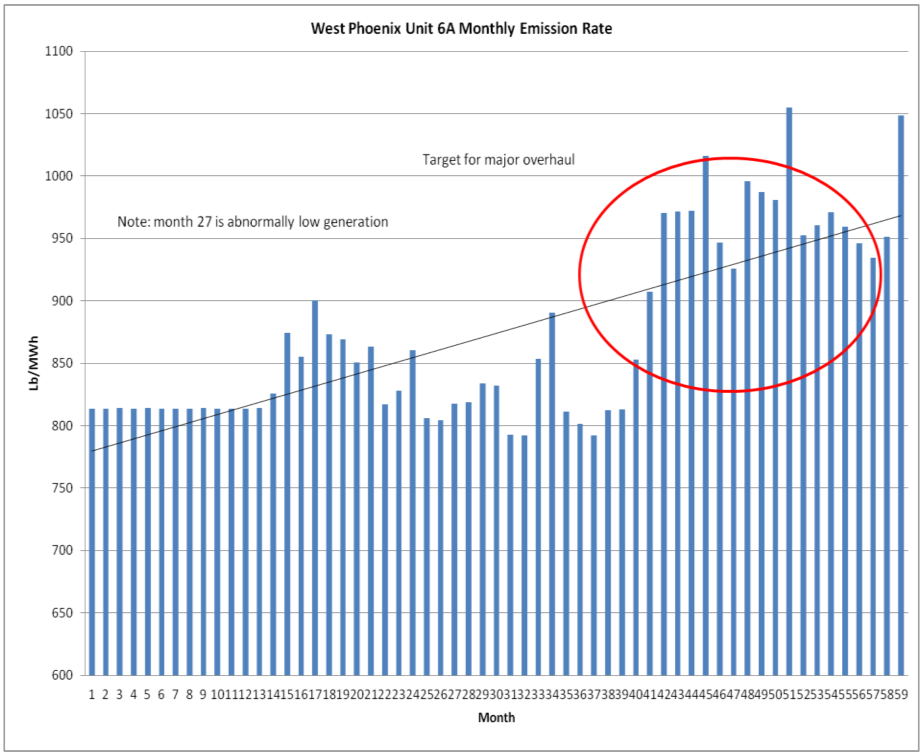


While we have not yet fully evaluated the extent to which heat rate improvements at NGCCs should be incorporated in the Block 1 calculations, it seems clear that those calculations should include some improvements to NGCC units. The technical literature[146] concerning efficiency degradation at NGCCs suggests ongoing O&M efficiency improvements can be achieved based on enhanced turbine cleaning operation and regular turbine maintenance.

In addition, the data we have reviewed to date shows degradation in monthly CO_2 emission rates at some units (*see* Fig. 14, below for data from West Phoenix Unit 6A) that may be related to the use of the unit without the heat recovery steam generator or to some other significant malfunction, suggesting that this issue merits a detailed evaluation.

[146] Fig. XX displays the performance data reported by EPA for the 73 units ("EPA Data Set") converted from gross to net emissions by application of a 3 percent correction factor in the NSPS rulemaking. *See* Memorandum from OQAPS to EGU, *Design Data for New Combined Cycle Facilities*, Document ID No. EPA-HQ-OAR-2011-0660-0068, (Apr. 12, 2012), *attachment entitled* "Gas Turbine World Performance Specifications."

Fig. 14- West Phoenix Unit 6A Average Daily Emission Rate



In addition to O&M improvements, there are a number of potential equipment upgrades that operators of gas-fired combustion turbines can undertake in order to reduce emissions. These include the following:

- Adding heat recovery steam generators ("HRSGs") to combustion turbines that operate more than 1,200 hours per year;
- Installing inlet air chilling or cooling at units that operate at warm temperatures;
- Using inlet air chilling or cooling preferentially to duct burners for increased power; and
- Using supplemental solar thermal units to heat the feedwater to the HRSG.

Accordingly, EPA should study the heat rate improvements that can achieved through enhanced O&M practices and equipment upgrades at gas-fired units and should incorporate these improvements into its final emission guidelines.

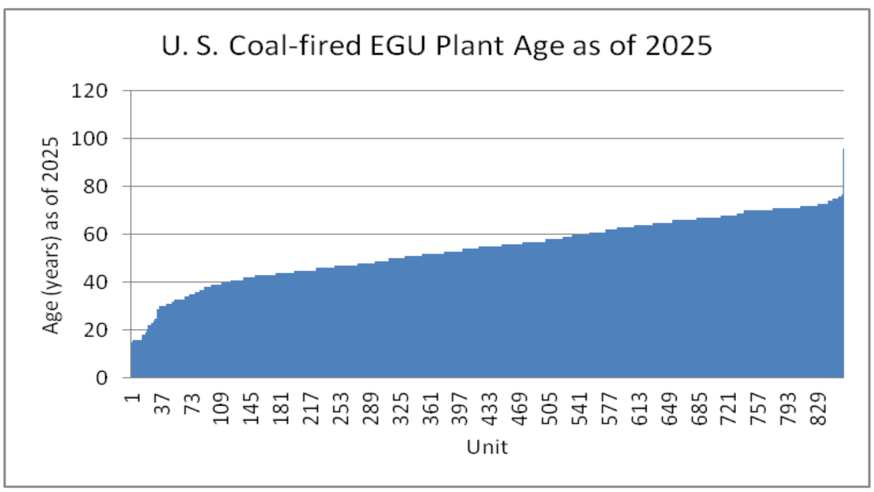
We note here that EPA must regulate emissions from *all* fossil fuel-fired EGUs that deliver electricity to the grid, including simple-cycle CTs, peakers, and low capacity factor units. We acknowledge that most CTs, peakers, and other low capacity-factor units were not included under EPA's 111(b) rule, which is a prerequisite to coverage under 111(d). In our 111(b) comments, argued that EPA must cover *all* fossil units that deliver electricity to the grid in that rule.[147] We reiterate that point here, and urge the agency to include any such units in the pool of EGUs covered under the CPP as well. We also reaffirm and incorporate by reference our stance in the 111(b) context that EPA must close off all loopholes relating to EGU definition and fuel usage to ensure that facilities do not evade regulation through technicalities.[148] The agency must foreclose the loopholes we identified in our comments and ensure that the CPP covers any unit that would be regulated under the amended 111(b) rule if it were new.

B. Building Block 2

1. While We Oppose Increased Use of Natural Gas, Building Block 2 Is a Surrogate for Coal-Plant Retirements Occurring Over the Long Term.

It is well documented that the U.S. coal-fired EGU fleet is aging and faces continued economic competition from renewable sources and gas-fired generation, as well as increasing public opposition to the use of high-emitting fossil fuels for energy. There is little doubt that the sector will continue to experience a large number of retirements and declining capacity factors for those units that remain in the near future.[149] Due to a number of factors, including the changing economics of the energy sector, a large wave of coal retirements will occur in the coming years. The Energy Information Agency ("EIA") projects 60GW of retirements in the next few years.[150]

Fig. 15- Age of U.S. Coal-Fired EGUs as of 2025

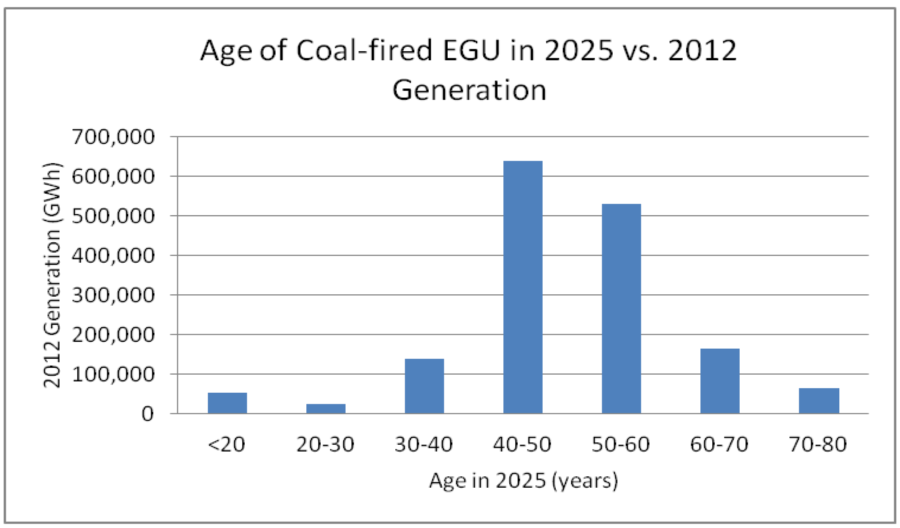


[147] Sierra Club et al., *supra* n. 115, at 43-65, 94-101.
[148] *See id.* at 43-70.
[149] *See* EPA, *2012 Coal Unit Characteristics, National Electric Energy Data System (NEEDS v4.10MATS) frame (EPA, December 2011) with additional information EPA, 2013*, *available at* http://www.epa.gov/airmarkets/images/CoalUnitCharacteristics2012.xls.
In these presentations, data for idled or reserve units that generated less than 100 GWh of electricity in 2011 have been excluded.
[150] *See, e.g.*, EIA, *Planned coal-fired power plant retirements continue to increase* (Mar. 20, 2014), *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=15491.

As Fig. 15 above illustrates, the median age of a coal-fired unit in 2025 (assuming no retirements) will be 52 years, whereas the average design life assumed at the time of these units' construction was 30 to 40 years. A review of approximately 300 coal units that retired between 1993 and 2012 indicates that the average age at the time of its retirement is 53 years.[151] This figure is comparable to the coal fleet that the Sierra Club's Beyond Coal Campaign has actively tracked since 2010. The average age of retirement for units tracked by the Sierra Club that have already retired is 54 years.

This estimate of average retirement age is consistent with the prevailing engineering analysis. The highly respected engineering text *Steam, Its Generation and Use* by Babcock &Wilcox notes that unit availability sharply declines after 25 years and assigns a typical life of 25 years for the superheater, 30 years for the reheater, 35 years for the economizer, and 40 years for the lower furnace.[152] "Life extension" of a unit by replacing these major components is sometimes feasible, but is not "routine maintenance" and normally will (and should) trigger the application of more rigorous environmental requirements. U.S. coal-fired generation is expected to decline even more dramatically in the following decade, since there will be relatively few coal-fired units under 40 years old by 2025.

Fig. 16 - Age of U.S. Coal-Fired EGUs as of 2025 vs. Generation in 2012



[151] This list is based on EIA Form 860 Y2012 submissions and covers retirements between 1993 and 2012, plus one retirement from 1970.

[152] Stultz and Kitto, eds., Babcock & Wilcox Co., *Steam: Its Generation and Use* (40th ed. 1992), Ch. 46-2, 46-4, Table 1.

Table 3- Age of U.S. Coal-Fired EGUs as of 2025 vs. Generation in 2012

Unit Age (years)in 2025	Capacity (GW)	2012 Generation (GWh)	2012 Capacity Factor
<20	8.3	52,954	.75
20-30	3.9	25,204	.69
30-40	22.4	138,247	.70
40-50	99.7	637,786	.73
50-60	102.2	530,063	.59
60-70	39.9	164,032	.47
>70	15.5	64,312	.47

Fig. 16 and Table 3 show that by 2025, the units responsible for 758 GWh in 2012 (47 percent of the coal-fired generation that year) will have retired or will be over 50 years old and nearing retirement.[153] This assessment is consistent with several analyses by the Brattle Group[154] and others.[155]

EPA does not directly address this important issue in the process of establishing BSER. Instead, the agency projects a reduction in generation from coal-fired EGUs as a result of what it terms "gas redispatch" under Building Block 2. However, EPA does not propose to regulate the dispatch of NGCCs, but rather to limit the dispatch of coal-fired EGUs. Under this concept, EPA assumes *for purpose of target-setting* that the dispatch of existing coal-fired EGUs will be reduced by the amount of underutilized NGCC capacity that is available in the state. *See, e.g.,* 79 Fed. Reg. 34,862-66. EPA is clear that it does not expect that compliance with the target set using the coal/gas redispatch will actually occur by the full amount of excess gas capacity that is available for redispatch.[156] Indeed, when EPA analyzed the likely compliance path that would be the least cost solution to its target rates, its IPM model predicted a substantial number of coal plant retirements in lieu of added utilization of existing NGCCs.[157]

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[153] In 2012, when this cohort was 40 to 50 years in age, the capacity factor started to decline to a level associated with "old" units.

[154] Aydin, et al., The Brattle Group, *Coal Plant Retirements Feedback Effects on Wholesale Electricity Prices* (Nov. 2013), attached as **Ex. 11**; Celebi, et al., The Brattle Group, *Potential Coal Plant Retirements: 2012 Update* (Oct. 2012), attached as **Ex. 12**.

[155] *See, e.g.,* Union of Concerned Scientists, *Ripe for Retirement: The Case for Closing America's Costliest Coal Plants* (Nov. 2012), attached as **Ex. 13**, at 17-18.

[156] *See, e.g.*, 79 Fed. Reg. at 34,863 ("Although producing over 1,400 TWh of generation in 2020 from existing NGCC units *is not actually required*, because states may choose other abatement measures to reach the state goals, the EPA nevertheless believes that producing this quantity of generation from this set of NGCC units is *feasible*.") (emphasis added).

[157] *See* EPA, *EPA Analysis of the Proposed Clean Power Plan, Supplemental Documentation for the Proposed Clean Power Plan: IPM Run Files*,

EPA set the total reduced coal utilization under Building Block 2 at 376 GWh/yr—a 26 percent reduction from 2012 coal-fired generation levels.[158] This figure is reasonably close to the 425 GWh/yr of coal-fired generation that would occur if all units that are older than 50 years in 2020 (the proposed effective date of the coal/gas redispatch) were to retire, as depicted in Fig. 16 and Table 3 above. As the Brattle Group study cited above points out, the rate of "voluntary" coal plant retirements is highly dependent on future natural gas prices which are impossible to predict.[159] Moreover, plant operators and state regulators are unlikely to assign a probability of closing a plant by a certain date until a final determination is made. For this reason, EPA has made a rational determination not to base its goal-setting calculations for reduced utilization of coal-fired EGUs based on retirements directly, but instead on the availability of underutilized NGCC capacity.

We have serious reservations about the use of natural gas as a replacement for coal. As we discuss in Section X, a significant body of evidence indicates that methane leaks associated with nonconventional production of natural gas (such as shale or tight gas extraction), as well as with the processing, transmission, and distribution phases of the industry, may cause climate change impacts on a par with those of coal combustion. In the Clean Power Plan, however, we emphasize that EPA does *not* require any source or group of sources to increase the use of natural gas. Instead, the agency uses the existence of underutilized NGCC capacity to mandate a reduction in the amount of coal-fired generation. As such, we view the Building Block 2 exercise as a surrogate or proxy for an estimation of the amount of reduction in coal-fired generation that is feasible through retirements or reduced utilization. Building Block 2 generates far more reduction in coal-fired generation than any other element in the proposal, and does so by 2020—the beginning of the compliance period. Building Block 2 also has the favorable attributes of being objectively determined using current data and of being demonstrably feasible. Further, it results in a set of target emission rates that are likely to meet or exceed the reductions that would flow from "business as usual" retirements and curtailments.

Therefore, we emphasize that displaced coal should be replaced with renewable energy and energy efficiency (as opposed to natural gas) to the greatest extent possible. We believe the agency has significantly underestimated the impact of recent RE cost reductions and the growth in momentum in that sector and strongly suggest that EPA set a more aggressive set of EE/RE targets. While we support the use of a limitation on coal-fired EGU dispatch under Building Block 2 for target setting, we intend to work with our state partners to ensure that compliance under state plans does not lead to increased use of natural gas.

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http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html (last visited Nov. 16, 2014).

[158] These calculations are based on data included *Appendix 1: Proposed Goals* to the *Goal Computation TSD, available at* http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-state-goal-data-computation_1.xlsx.

[159] *See generally* Aydin, *supra* n. 154.

2. EPA Must Improve and Strengthen Building Block 2.

a. When Applying Building Block 2, EPA Should Account for Retirements Occurring in the Near Term.

EPA's Building Block 2 calculation assumes that emissions from units that retired in 2012 (the base year) or that will retire (according to their operators) in the next few years are relevant for purposes of setting a baseline. However, the rule's proposed compliance period will not begin until 2020. By including business-as-usual retirements in the target-setting exercise, EPA fails to identify the *best* system of emission reductions, since states with recent or imminent coal plant retirements may face relatively more lenient standards than other states. We urge the agency not to allow states to ignore near-term changes in the generation mix, including the large number of retirements expected to occur between 2012 and 2017 or 2018, when final state plans are due.

Under EPA's approach, generation from fossil fuel-fired steam EGUs is expected to be reduced in equal measure to the excess NGCC capacity that is available for redispatch. For example, in Virginia, redispatch to underutilized NGCC units would generate approximately 6 million MWh, so the state is expected to reduce its coal-fired generation[160] by that same amount. Virginia's coal-fired generation amounted to 13.6 million MWh in 2012, but only 10.3 million of those MWhs were generated by units that are expected to continue operating past 2015.[161] After a 6 million MWh reduction, the units that continue to operate can either generate 7 or 4 million MWh depending on whether or not EPA accounts for near-term coal retirements in its final guidelines. This is a much more substantial difference in stringency than the range of options under consideration for Building Block 1: a one-percent difference in heat rate improvements at these Virginia units is comparable to 40-70,000 MWh of generation reduction.[162]

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[160] In Virginia, 98 percent of fossil fuel-fired steam generation is coal-fired, so the Block 2 reductions are borne almost entirely by coal units.

[161] *See Goal Computation TSD, Appendix 7: Individual Unit Data, available at* http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-plant-level-data-unit-level-inventory_0.xlsx. As these data show, Virginia coal plants generated 13.6 million MWh in 2012. Excluding the units that have been announced for retirement—Bremo Bluff, Chesapeake, Clinch River, Glen Lyn, Hopewell, and Yorktown—reduces this figure to 10.3 million MWh.

[162] If near-term coal retirements are removed from EPA's goal-setting formula, as we advocate, we recognize that some of Virginia's excess NGCC capacity may be reduced for redispatch starting in 2020, since those units may increase utilization to replace the lost generation from the near term coal retirements. However, Dominion Energy, which services the Commonwealth, has announced its intent to procure new NGCC generation in the near future, which would leave substantial capacity at existing NGCCs available for redispatch. *See* Dominion, *Dominion North Carolina Power's and Dominion Virginia Power's Report of Its Integrated Resource Plan Before the North Carolina Utilities Commission and the Virginia State Corporation Commission*, Dkt. No. E-100, Sub 141, Case No. PUE-2014-00087 (submitted Aug. 29. 2014).

Tennessee's situation also illustrates this point. As of this writing, three coal-fired units in Tennessee that were included in EPA's goal-setting calculation have either retired or have announced plans to retire prior to the 2020 compliance period: Allen Steam Plant, Johnsonville Fossil Plant, and John Sevier Fossil Plant.[163] These three facilities generated approximately 7.5 million MWh in 2012,[164] and Tennessee's 2030 target emission rate under the Clean Power Plan is 1,163 lbs CO_2/MWh. Under Building Block 2, EPA calculates that Tennessee can redispatch approximately 3.3 million MWh annually from existing coal plants to existing gas plants if it scales up its gas-fired generation to a 70 percent capacity factor. But because the three retired (or retiring) units noted above will be removed from the state's generation mix regardless of the rule, the state can simply bypass the reductions needed satisfy Building Block 2. Even if Tennessee were to replace the 7.5 million MWh produced by these retiring units with generation from new combined-cycle gas plants (which we urge EPA not to permit for use as a compliance mechanism), it could avoid redispatching any existing gas units entirely and still achieve a final emission rate of 1,111 lbs CO_2/MWh if it adopted the measures specified under Blocks 1, 3 and 4. In fact, these three retirements would give the state enough of a compliance margin that it could reduce its heat rate improvements at existing coal plants to just two percent and still meet its final target, assuming full compliance with Blocks 3 and 4. On the other hand, if these three plants were simply deleted from both EPA's target-setting process and from a determination of state compliance, Tennessee would need to find some other way of achieving the emission reductions under Block 2, which would be determined by the then-available excess NGCC capacity.

EPA should improve the fairness and effectiveness of the proposal by excluding near-term "business-as-usual" plant retirements from the determination of BSER and the state emission targets. The most accurate process would be for EPA or each state to calculate the state's Building Block 2 target based on the most recent available data when the state submits its compliance plan for the agency's approval. Thus, if Tennessee were to submit its plan to EPA in 2016, the agency would use 2015 data rather than 2012 data to calculate Tennessee's interim and final target emission rates. If the state took an extra year and submitted its plan in 2017, EPA would use 2016 data. This would ensure that plants that existed as of 2012 but have retired since that time are not included in either the target-setting or compliance-determining process. It would also ensure the use of the most accurate information concerning available underutilized NGCC capacity for purposes of calculating the enforceable state emission targets. Moreover, EPA should delete from its target calculations and compliance determinations any still-existing plants with legally enforceable retirement obligations in place at the time the

[163] *See* Madeline Faber, *TVA announces decision about Memphis' Allen Fossil Plant*, Memphis Bus. J. (Aug. 21, 2014), *available at* http://www.bizjournals.com/memphis/news/2014/08/21/tva-announces-decision-about-memphis-allen-fossil.html?page=all; Tenn. Valley Auth., *Johnsonville Fossil Plant*, http://www.tva.com/sites/johnsonville.htm (last visited Nov. 11, 2014); Tenn. Valley Auth., *John Sevier Fossil Plant*, http://www.tva.com/sites/johnsevier.htm (last visited Nov. 11, 2014).
[164] *See Goal Computation TSD, Appendix 7: Individual Unit Data, supra* n. 161.

compliance period begins. This would ensure that Building Block 2 is fully effective in states like Tennessee.

Our recommended approach for plant retirements would have the added benefit of resolving uncertainties regarding combined cycle plants that are currently under construction. These plants are defined as NGCC units that were in existence as of the effective date of the section 111(b) proposal—January 8, 2014—but that were not operating as of 2012. Under EPA's current approach, 15 percent of the generating capacity of an under-construction NGCC is included in Building Block 2's redispatch scenario, whereas the other 55 percent is reserved "to meet other system needs presumed to have motivated the construction of the 'under construction' NGCCs"—namely, to replace recent or imminent coal retirements.[165] However, by using 2015 or 2016 data as a baseline, any facilities under construction as of January 2014 will likely be in operation and can simply be considered existing NGCC units. As such, any underutilized capacity can be included in the redispatch scenario described in Building Block 2.

b. Under Building Block 2, EPA Should Assume Redispatch of the Highest Emitting Units Before Others.

Building Block 2 reflects EPA's determination that a certain percentage of generation from a state's existing steam EGUs (either coal-fired units or oil- or gas-fired boilers) can be replaced with generation from existing and under-construction NGCCs. EPA's emission targets assume that an operator can reduce the annual emissions from a coal-fired power plant simply by operating the unit less. In order to provide a reasonable assurance of system reliability, EPA limits the reduced dispatch of steam EGUs to the amount of generation that existing NGCCs could provide if they operated at 70 percent of their capacity. The manufacturers of these units have confirmed their technical ability to operate at 70 percent capacity factors, and eGRID data reveal that 94 NGCCs operated at capacity factors of 70 percent or higher in 2012.[166] We therefore support EPA's technical determination that states can scale down utilization of their steam EGUs consistent with an increase in NGCC dispatch up to a 70 percent capacity factor without jeopardizing electric system reliability.

However, EPA must reconsider the way it allocates reduced dispatch among the coal and O&G steam fleets. EPA's current proposal follows a proportionate redispatch model with regard to coal and O&G steam units. Rather than targeting the coal units, which are generally the highest emitters, EPA limits the dispatch of all steam EGUs in proportion to their share of the state's 2012 generation. This approach, which EPA fails to justify or explain, results in a less stringent emission limitation, since existing O&G steam units generally emit 20-30 percent less CO_2 per MWh than existing coal-fired plants. For instance, in Louisiana, the average emission rate of coal-fired EGUs is 2,323 lbs CO_2/MWh, whereas the average rate of O&G steam units is

[165] *Goal Computation TSD* at 12.
[166] EPA, *Data File: Unit-Level Data Using the eGRID Methodology (XLS)* (June 2014), *available at* http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-egrid-methodology_0.xlsx.

1,581 lbs CO_2/MWh.[167] By preserving the historical ratio of coal-to-O&G steam in its standard-setting process, EPA fails to apply the best system of emission reductions. Instead, EPA should employ an environmental dispatch limitation for Building Block 2, which would assume that dispatch of the highest emitting sources, typically coal-fired EGUs is limited *first*, while the O&G steam fleet would reduce its dispatch only if additional NGCC capacity (up to 70 percent) remained after coal generation is reduced to zero.[168]

For example, in Louisiana, an environmental dispatch limitation approach would reduce the state's final emission target by approximately 6.5 percent (*see* Table 4 below), which is greater than the reductions for that state expected under Building Block 1.

Table 4- Emission Goals for Louisiana- EPA's Approach vs. Environmental Redispatch

	Expected 2020 Emission Rate (lb/MWh)	Interim 2020-2029 Goal (lb/MWh)	Final 2030 Goal (lb/MWh)
Louisiana Emission Targets- EPA's Proposal	1,015	948	883
Louisiana Emission Targets- Environmental Dispatch Limitation Approach	949	887	826

On a national level, this approach to dispatch limitation would reduce CO_2 emissions by around 12 million tons per year, approximately one-sixth of the reduction that will be through Block 1's heat rate improvements across the nation's coal-fleet.[169] In addition, an environmental approach to dispatch limitation could expect simple cycle gas-fired combustion turbines ("CTs") that operate at capacity factors more suited for lower-emitting NGCCs (i.e., load-following and base load uses above a 10 percent capacity factor) to reduce dispatch in favor of available NGCC capacity. This would reduce the use of natural gas and would cut emissions even further.

Environmental dispatch limitation is therefore an easily achievable and straightforward way for EPA to bolster the Clean Power Plan's efficacy and achieve greater CO_2 reductions. We are aware of no advantages to the proportionate redispatch protocol described in EPA's rule,

[167] *See Goal Computation TSD, Appendix 1- Proposed Goals*, *supra* n. 161 (including 2012 emissions data for each state and calculating reductions under each building block).

[168] In a handful of states, the O&G steam fleet is higher-emitting on average than the coal fleet, and would hence limit their dispatch first under the approach we describe in this section.

[169] EPA describes the Building Block 1 emission reductions as occurring prior to application of Building Block 2, but in its calculation of state emission targets, the agency applies the 6 percent heat rate improvements to the amount of coal-fired generation that is assumed to remain *after* the curtailments under Building Block 2. By our calculation, then, Block 1's heat rate improvements will reduce emissions nationwide by 72.6 million tons of CO_2.

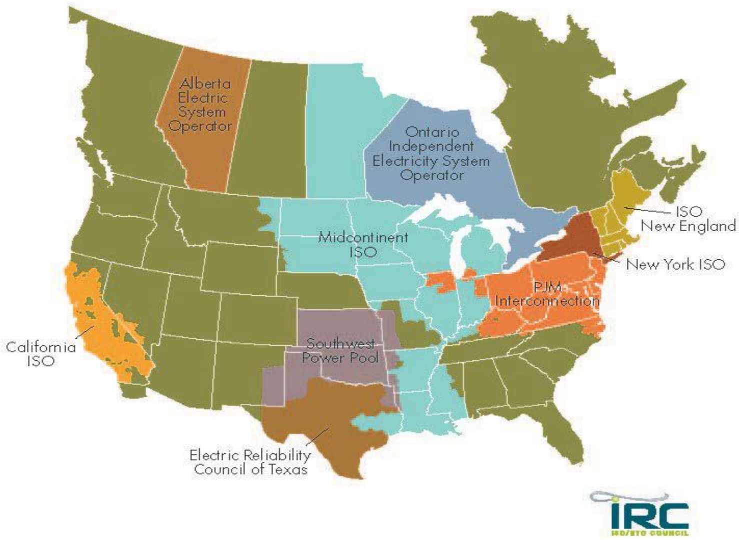
and the agency has not explained (nor provided record support for) its decision. Therefore, if the Clean Power Plan is to reflect the *best* system of emission reduction, as the Clean Air Act requires, EPA must adopt the environmental dispatch limitation approach we have described in this section.

c. Under Building Block 2, EPA Should Adopt a Regional Redispatch Approach.

EPA's current model for Building Block 2 limits NGCC utilization to the point at which all of the electricity generated by steam-driven fossil plants has been replaced with electricity from NGCC units, even if the latter have not reached a 70 percent capacity factor. This occurs in states with excess NGCC capacity and little existing coal-fired generation. EPA's approach also limits coal-fired EGU dispatch in coal-reliant states with no or limited in-state NGCC facilities such as Kansas and Kentucky, even though customers in those states are served by gas-fired units in neighboring states that dispatch without regard to state lines. By contrast, some states with considerably less carbon-intensive electricity sectors must undertake significant changes to their generation mix to meet Block 2's reduction assumptions. For example, Oklahoma produced roughly equal amounts of coal- and NGCC-fired generation in 2012, and its obligations under Block 2 assume a full 50 percent reduction in coal-fired generation starting in 2020.

In its recent NODA, EPA solicits comment on whether a regional rather than state-specific structure for Block 2 could ease these disparities. *See* 79 Fed. Reg. at 64,547. We support a regional approach because it would more accurately calculate the availability of underutilized NGCC capacity nationwide and more fairly assign emission reduction obligations across the states. Existing power plants are, in reality, components of a complex and interconnected electricity grid that stretches across state lines. EPA's final guidelines will embody the *best* system of emission reduction if the state goals reflect the full extent of emission reductions available to coal-fired units, whether the NGCC excess capacity is in the same state or a neighboring one. The map of independent system operators ("ISOs") is presented in Fig.14 below.

Fig.17- ISO Divisions Across the United States and Canada



To provide one example, ISO-NE, New England's regional transmission organization, includes 300 generating plants and 8,000 miles of transmission lines. Within each ISO system, plant dispatch and electricity flows are determined not by individual state regulators but by ISO-NE rules and bidding activities. These factors—not state lines—should determine the actual amount of existing NGCC capacity that is available for redispatch under Block 2.

In the following table we present a calculation of the coal dispatch limitation that occurs if the available existing NGCC capacity in nine states that are served by the Midwest Independent System Operator ("MISO") are considered as a group. A regional allocation of redispatch under Block 2 would produce little change in the overall limitation on coal generation, but would provide for a more even allocation of emission reduction obligations between "low impact" states, such as North Dakota and Indiana, and "high impact" states, such as South Dakota, Michigan and Minnesota. This approach would also facilitate regional cooperation by limiting the difference between rule's impact on states that are "winners" and those that face a more challenging regulatory burden.[170]

[170] A regional approach to coal dispatch limitation will also provide for more equitable treatment of coal-fired units on lands of the Navajo Nation and of the Ute Tribe of the Uintah and Ouray Reservation, which lack NGCC capacity entirely. We will submit comments on EPA's supplemental proposal for Indian lands and U.S. Territories by the December 19, 2014 submission deadline.

Table 5- MISO Regional Coal Dispatch Limitation

State	Historical Coal Generation (MWh)	EPA's Proposed Coal Generation (MWh)	Regional Dispatch Coal Generation (MWh)
South Dakota	2,923,161	958,046	2,460,084
North Dakota	28,186,691	28,186,691	23,721,453
Michigan	53,210,780	41,091,564	44,781,313
Indiana	87,213,268	83,034,543	73,397,244
Illinois	79,166,165	66,157,723	66,624,936
Missouri	72,939,512	65,012,570	61,384,687
Wisconsin	32,112,721	24,062,122	27,025,535
Iowa	33,055,156	26,779,114	27,818,673
Minnesota	21,989,584	10,699,001	18,506,070
SUM	**410,797,038**	**345,981,374**	**345,719,995**

Applying the same concept to five of the states served by the Western Electric Coordinating Council ("WECC") results in an additional 11 million MWh of reduced coal generation (*see* Table 6 below). It also redistributes the allocation of compliance obligations between Montana and Wyoming, on the one hand, which share none of the Building Block 2 burden under EPA's plan, and Nevada, on the other hand, which would otherwise be expected to eliminate all of its existing coal-fired generation.

Table 6- Western States Regional Coal Dispatch Limitation

State	Historical Coal Generation (MWh)	EPA's Proposed Coal Generation (MWh)	Regional Dispatch Coal Generation (MWh)
Wyoming	42,907,427	42,617,555	32,131,352
Utah	27,332,140	20,797,210	20,467,753
Montana	14,447,406	14,447,406	10,818,982
Nevada	4,133,662	0	3,095,505
Idaho	0		0
SUM	**88,820,635**	**77,862,171**	**66,513,592**

The preceding tables are intended to be illustrative; to simplify the calculation process we have assumed that all of the units in the states are part of MISO or WECC (which is almost but not completely correct). Moreover, we recognize that it may be more appropriate to organize and evaluate generating capacity on a sub-regional basis. The concept we recommend is for EPA to evaluate the available underutilized capacity on the basis of how the electric generation and transmission system actually works, rather than on the basis of state jurisdiction. Once a dispatch limitation is determined for each coal-fired unit in a given system, each unit's assumed available limitation can then be incorporated in the calculation of the emission targets for the state in which that unit is located.

d. EPA Should Incorporate Appropriate NGCC Emission Rates in Its Determination of Block 2 Emission Rate Reductions.

In its proposal, EPA assumes that the fossil-steam generation curtailed under Block 2 will all be replaced by existing NGCC capacity in the state at the current emission rates of those units. In our comments on Block 3 we demonstrate that EPA should assume that at least some of the displaced fossil-steam generation is replaced by renewable generation. As we show above, however, it is also reasonable and appropriate to require some level of HRI for NGCCs, especially high-emitting existing NGCCs. Accordingly, whether or not EPA explicitly adopts Block 1 HRI as we suggest, the agency should base emission levels for any NGCC replacement capacity that it assumes on reasonable HRI at those units in determining Block 2 emission rate reductions.

C. Building Block 3

1. Building Block 3 is Legally and Technically Justified as an Element of BSER, but EPA Must Modify Its Approach to Strengthen It.

Renewable energy generation, either as a component of the BSER or as a measure to quantify reduced utilization from affected EGUs, is a cost-effective system of emission reduction. It also has much lower environmental impacts than fossil fuel-fired generation and is adequately demonstrated, as shown by the experience of states and utilities that have implemented renewable energy policies and programs over the course of years and decades. It is therefore wholly appropriate as an element of the Clean Power Plan.

a. Declining Costs of Renewable Energy

Renewable energy must play a central role in any regulatory program designed to reduce CO_2 emissions from the nation's electric sector. Not only are RE resources fully capable of replacing fossil fuel-fired generation from a technical standpoint, these clean technologies have undergone dramatic price reductions in both the long- and near-terms, and are now at or near grid parity with, or are cheaper than, fossil-fired options in many parts of the country. This trend will only increase in the coming years as wind and solar technology become increasingly economical in both the U.S and around the world.[171]

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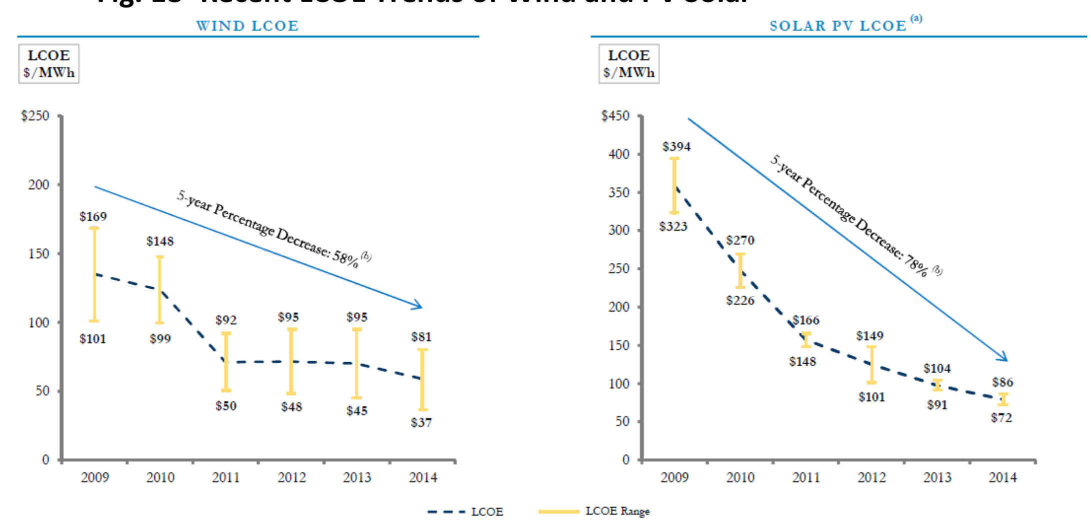
[171] *See, e.g.*, Deutsche Bank, *Solar- 2014 Outlook: Let the Second Gold Rush Begin* (Jan. 6, 2014), attached as **Ex. 14**, at 8 (indicating that solar energy has reached grid parity in at least 10 states without additional state subsidies with another 12 states fast approaching grid parity; this could grow to as many as 47 states by the end of 2016); Citi, *Energy 2020: The Revolution Will Not Be Televised as Disruptors Multiply* (July 28, 2014), attached as **Ex. 15**, at 41 ("Solar has reached socket (residential) parity in many global regions at the residential level with more to come, and utility scale parity expected over the next few

Abundant research documents a large decline in the prices of wind and solar generation in recent years. Lazard's most recent estimate of the levelized costs of different generation resources shows that wind prices have decreased on average by 58 percent and utility-scale solar photovoltaics ("PV") have decreased 78 percent over the last five years.[172] These significant decreases are primarily the result of technological improvements that have enabled projects to operate at higher capacity factors, as well as a decline in the price of inputs in the manufacturing supply chain.[173] Specifically with respect to wind, turbine prices have decreased substantially in recent years due to improved turbine technologies and more favorable contractual terms for turbine purchasers, as well as continued technological advancements (such as increased rotor diameters and hub heights) that are improving the projects' capacity factors.[174] With respect to solar, lower prices of inverters and racking systems have contributed to this decrease.[175]

Fig. 18- Recent LCOE Trends of Wind and PV Solar[176]



Renewable generation, particularly wind power, has become more cost-effective than conventional generation resources in many circumstances. The left blue bars in Figure X below represent the lower end and the red bars represent the higher end of the current unsubsidized

years. Besides pure economics, the need for utilities to diversify their fuel mix is crucial to insulating them from volatility and the likely upward movement in gas prices over the longer term, a need that was well documented as we surveyed electric utilities in the US."); Press Release, Bloomberg New Energy Finance, Onshore Wind Energy to Reach Grid Parity by 2016 (Nov. 10, 2011), attached as **Ex. 16**.

[172] *See* Lazard Ltd., *Lazard's Levelized Cost of Energy Analysis—Version 8.0* (Sept. 24, 2014), attached as **Ex. 17**, at 9.

[173] *Id.*

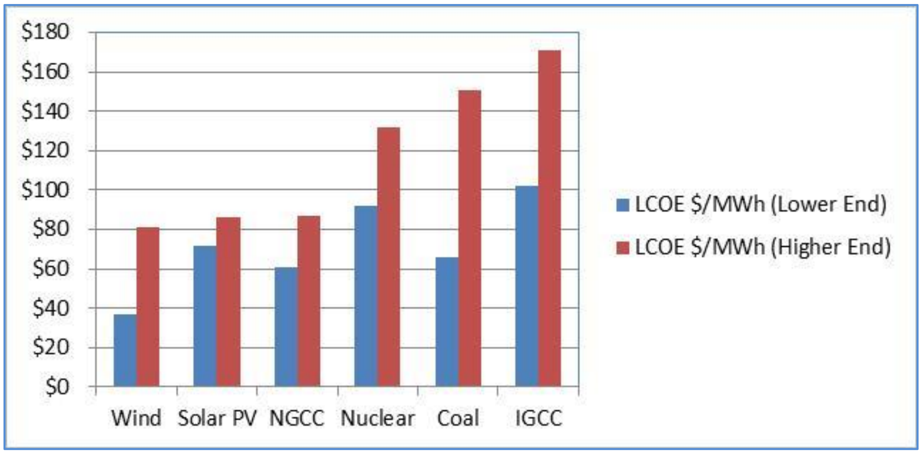
[174] DOE, *2013 Wind Technologies Market Report* (Aug. 2014), attached as **Ex. 18**, at 47-48.

[175] Solar Energy Indus. Assoc. ("SEIA"), *U.S. Solar Market Insight Report, 2013 Year-in-Review: Executive Summary* (2014), attached as **Ex. 19**, at 5.

[176] Lazard, *supra* n. 172, at 9.

costs of different generation resources, including utility-scale wind and solar, NGCC units, nuclear plants, conventional coal-fired power plants, and integrated gasification combined cycle ("IGCC") units. While utility-scale solar is still more expensive than natural gas, it is currently competitive in more than ten states. Analysts estimate that, in these grid parity states, installed capacity growth will grow about 300 percent in the next four years due to improved economics of solar, including the availability of low cost financing and solar leasing.[177]

Fig. 19- LCOE of Different Electricity Generation Resources[178]



Wind power purchase agreement ("PPA") prices have also reached all-time lows. According to the Department of Energy ("DOE"), the national average levelized price of wind PPAs has fallen from $70/MWh in 2009 to $25/MWh in 2013.[179]

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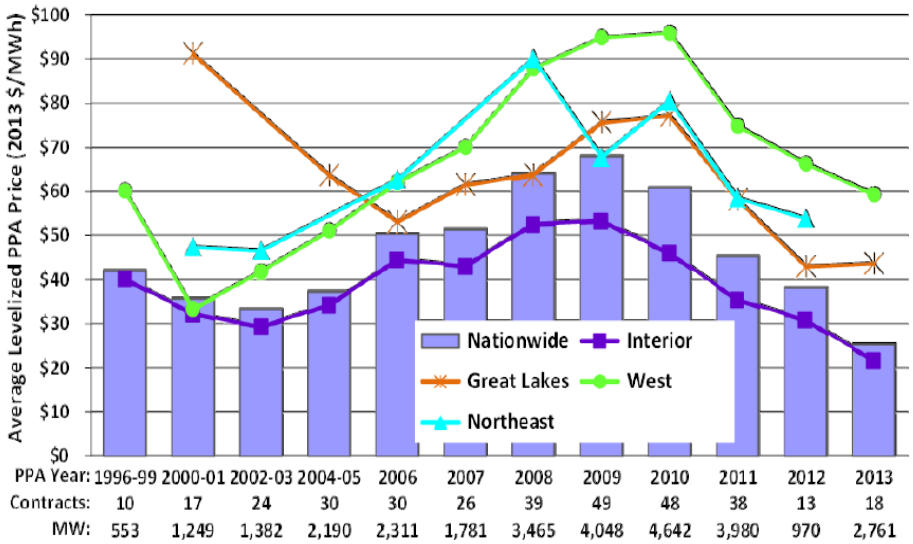
[177] Deutsche Bank, *supra* n. 171, at 8. Deutsche Bank also estimates that, even with a lower tax credit (10 percent), solar would reach price parity with conventional electricity in more than half of the country—36 states—in 2016. *Id.*, at 9.

[178] Prepared with data from Lazard, *supra* n. 172, at 2.

[179] DOE, *supra* n. 174, at 58.

Fig. 20- Generation-Weighted Average Levelized Wind PPA Prices by PPA Execution Date and Region[180]



b. Environmental Impacts and Benefits of Renewable Energy

Renewable technologies such as wind and solar emit no carbon in their operation. Renewable energy actually reduces emissions of CO_2 and other air pollutants such as NO_x, SO_2, Hg, and PM insofar as renewable generators displace or reduce the utilization of fossil fuel-fired units.[181] EPA has estimated that the implementation of its proposed building blocks, which include incremental renewable energy generation, would result in CO_2 emissions reductions of 30 percent below 2005 levels.[182] However, as we discuss below, UCS estimates that higher levels of renewable energy deployment in target-setting would result in even larger decreases—approximately 40 percent, assuming that renewables primarily displaced natural gas.[183] If renewable generation instead displaced coal, the amount of carbon reductions would be considerably larger still.[184]

Renewable generation has reduced non-air environmental impacts, particularly when compared to fossil fuel-fired generation. Solar technologies have "very low operating costs and require minimal non-solar inputs."[185] In addition, solar PV panels installed on rooftops have no land use impacts.[186] For utility-scale solar energy, the land-use impacts "vary from region to region" and depend on the approaches taken to avoid or mitigate those impacts during project

[180] *Id.* at 59.
[181] DOE, *SunShot Vision Study* (Feb. 2012), at 2.
[182] RIA at 3-20, Table 3-6.
[183] Union of Concerned Scientists ("UCS"), *Policy Brief: Strengthening the EPA's Clean Power Plan* (October 2014), attached as **Ex. 20**, at 4.
[184] *Id.*
[185] DOE, *supra* n. 174, at 1.
[186] *Id.* at 4-5.

development.[187] With regard to water impacts, solar PV significantly reduces water consumption from the conventional electricity generation it displaces, as it requires very little water for the occasional washing of panels.[188] Water impacts of concentrated solar power ("CSP") depend on the type of cooling technology used; if CSP is deployed with dry or hybrid (as opposed to wet) cooling towers, water use can be reduced by 40 to 97 percent as compared to wet cooling.[189] In addition, wind generation does not produce solid waste or require cooling water. 79 Fed. Reg. at 34,883.

Renewable energy technologies also help to diversify the energy mix and reduce the economic risks associated with overreliance on natural gas. Wind PPAs, for example, currently exhibit a "high degree of long-term price stability," with average prices holding steady through 2031.[190] Similarly, multi-decade solar energy PPAs allow utilities to lock in low prices for many years. In contrast, natural gas prices can be "quite volatile . . . and difficult to lock in for any significant duration," making it difficult to capitalize on the low prices of gas in the long term.[191] While the short-term risk of gas prices can be hedged using conventional financial instruments and investment techniques, these options are not effective for longer-term hedging.[192] In contrast, wind and solar contracts "provide ample long-term hedge value . . . [and] are, on average, competitive natural gas fuel savers."[193]

c. Transmission and Integration Requirements of Renewable Technologies

Recent developments in transmission line construction and best practices in renewable energy dispatch are helping to address any reliability concerns with respect to wind energy. Although inadequate transmission capacity can hinder both new and existing wind projects, recent developments in transmission line expansion mitigate these concerns.[194] Over 3,500 miles of transmission lines came online only in 2013 and investor-owned utilities made transmission investments of $17.5 billion.[195] There are currently 15,000 miles of transmission lines and over 170 projects in various stages of development in the U.S., worth more than $60 billion in potential investments.[196] The Edison Electric Institute has estimated that 76 percent of this new transmission capacity "would—at least in part—support the integration of renewable

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[187] *Id.* at 16.
[188] *Id.* at 15.
[189] *Id.*
[190] Bolinger, Mark, Lawrence Berkeley Nat'l Lab. ("LBNL"), *Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices*, LBNL-6103E (March 2013), attached as **Ex. 21**, at 4-13, 22.
[191] *Id.* at 8, 10.
[192] *Id.* at 3, 4, 22.
[193] *Id.* at 21.
[194] DOE, *supra* n. 174, at 66-67.
[195] Id. at 66.
[196] Id. at 66-67. 76 percent of which would—at least in part—support the integration of renewable energy

energy."[197] AWEA has also identified fifteen near-term transmission projects that, if completed, could support almost 60 GW of additional wind capacity.[198]

Of particular significance is the Competitive Renewable Energy Zones ("CREZ") project in Texas.[199] Completed in 2013, the CREZ includes "almost 3,600 circuit miles of transmission lines and was designed to accommodate up to 18,500 MW of total wind power capacity,"[200] and ERCOT reports that this project has largely resolved the problem of wind-related congestion between West Texas and other areas.[201] Other recent examples include the One Nevada transmission project, the Southern Nevada Intertie Project, and the Southwest Intertie Project North, each 500-kV and spearheaded by LS Power or an affiliate.[202] Offshore wind would also ease transmission constraints along the East Coast. In Maine, Emera Maine and Central Maine Power recently entered into a memorandum of understanding to explore the development of transmission projects to support 2,100 of wind capacity.[203] And because offshore wind is load-following, it can help lower grid congestion at peak demand periods.

As DOE reports, "[e]xperience in operating power systems with wind energy is . . . increasing worldwide, leading to an emerging set of best practices."[204] These practices have helped balance concerns regarding the variable nature of wind generation. For example, all ISOs and RTOs (as well as many utilities) now use centralized wind energy forecasting systems, a "vital [tool] for meeting reliability requirements and efficient scheduling of resources."[205] Furthermore "ISOs continue to refine scheduling and commitment processes, including updates like the MISO look-ahead commitment, the incorporation of wind into dispatch at MISO, the flexible ramping constraint at the CAISO, and sub-hourly exchange between markets."[206] Recent integration studies have estimated lower costs of wind integration than previously assessed; for example, Portland General Electric's estimates of integration costs have decreased from $11/MWh to less than $4/MWh.[207]

d. Renewable Energy Generation is "Adequately Demonstrated."

Renewable energy technologies are "adequately demonstrated" for the purposes of a BSER analysis under section 111. Wind and solar resources have been deployed by states,

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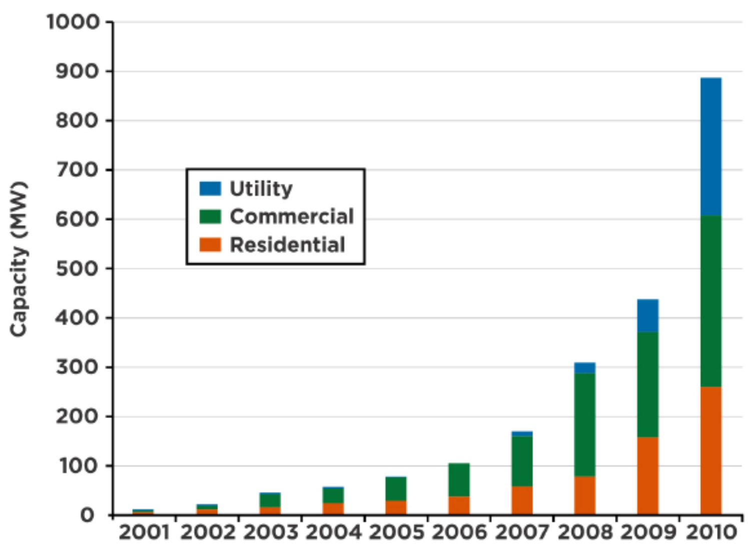
[197] DOE, *supra* n. 174, at 66.
[198] American Wind Energy Association ("AWEA"), *U.S. Wind Industry Annual Market Report Year Ending 2013,* "Transmission," *available at* http://www.awea.org/AnnualMarketReport.aspx?ItemNumber=6316&RDtoken=9132&userID=.
[199] DOE, *supra* n. 174, at 67-68.
[200] *Id.* at 67
[201] *Id.*
[202] *Id.* at 68.
[203] *Id.*
[204] *Id.* at 69.
[205] *Id.*
[206] *Id*. at 71.
[207] *Id.* at 70.

utilities, and merchant generators. These technologies have been growing rapidly and are becoming more cost-effective strategies for CO_2 emission reductions than approaches that continue to rely on conventional generation resources.

In 2010, solar energy provided less than 0.1 percent of U.S. electricity demand,[208] but solar installed capacity is now growing faster than any other renewable generation resource. Continued research and development, market forces, and state and federal policies "have helped reduce PV prices sharply and . . . have positioned the U.S. PV market for rapid future growth."[209] In addition, solar has enormous technical potential. Solar resources in the U.S. are "mostly good to excellent" at about 1,000 to 2,500 kWh/m^2/year.[210] Seven states in the U.S. Southwest (Arizona, California, Colorado, Nevada, New Mexico, Texas, and Utah) have "some of the best solar resources in the world."[211]

Grid-connected PV has grown significantly since the early 2000s in residential, commercial, and utility-owned applications, as shown in Fig. 21.[212] The utility market segment increased markedly between 2009 to 2010,[213] and growth has been particularly significant in recent years in Arizona, California, Colorado, New Mexico, New Jersey, New York, and Nevada.[214]

Fig. 21- U.S. Annual Installed Grid-Connected PV Capacity by Market, 2001-2010[215]



[208] DOE, *supra* n. 181, at 3.
[209] *Id.* at 4.
[210] *Id.* at 34.
[211] *Id.* at 4-5, 25, 36-37.
[212] *Id*. at 28.
[213] *Id*.
[214] *Id*.
[215] *Id.*

Wind technologies also evolved significantly in the last 15 years. The average nameplate capacity of newly installed wind turbines in 2013 was 1.87 MW, 162 percent higher than in 1998-1999.[216] Average hub heights and rotor diameters have also scaled during this period. The average hub height of wind turbines installed in 2013 was 80 meters, 45 percent greater than in 1998-1999.[217] Average rotor diameters have increased even faster; the average rotor diameter in 2013 was 97 meters, 103 percent greater than in 1998-1999.[218] Larger turbines are driving higher capacity factors for wind projects and allowing for increased generation from these resources.[219]

Renewable portfolio standards ("RPS") have been a major driver of renewable energy deployment in the U.S. Twenty-nine states and the District of Columbia have established RPS programs extending in most cases through 2020 or 2025.[220] Five additional states have voluntary renewable energy goals.[221] California has the most ambitious RPS in the country, requiring investor-owned utilities, electricity service providers, and community choice aggregators to purchase 33 percent of their electricity from renewable energy resources by 2020.[222] Spain and Germany have set target shares of energy from renewable resources for their gross energy consumption for 2020 that are even more stringent than EPA's proposal.

RPS programs in the U.S. have contributed to build robust markets for the supply of renewable generation technologies. States with mandatory RPS programs "have collectively deployed approximately 46,000 MW of new renewable energy capacity through year-end 2012."[223] Thirteen states installed a total of 1,087 MW of new wind energy capacity in 2013, and a total of 61,110 MW was operational at the end of that year in thirty-nine states and Puerto Rico.[224] In that same year, solar PV reached 4,751 MW, nearly fifteen times the capacity installed in 2008.[225] 410 MW of CSP capacity were also installed in 2013.[226] According to SEIA, more solar capacity was installed in 2012 and 2013 than in the thirty years prior, and these

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[216] DOE, supra n. 174, at 30.
[217] *Id.*
[218] *Id.*
[219] *Id.* at 30, 41.
[220] Bingaman et al., Stanford Steyer-Taylor Center for Energy Policy and Finance, *The State Clean Energy Cookbook, A Dozen Recipes for State Action on Energy Efficiency and Renewable Energy* (2014), attached as **Ex. 22**, at 31.
[221] *Id.*
[222] Cal. Exec. Order No. S-14-08 (Nov. 17, 2008), *available at* http://gov38.ca.gov/index.php?/executive-order/11072/ .
[223] Heeter et al., NREL/LBNL, *A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards*, No. NREL/TP-6A20-61042/LBNL-6589E (May 2014), attached as **Ex. 23**, at iv.
[224] AWEA, *U.S. Wind Industry Annual Market Report Year Ending 2013,* "U.S. Capacity & Generation," *available at* http://www.awea.org/AnnualMarketReport.aspx?ItemNumber=6305&RDtoken=35392&userID=.
[225] SEIA, *supra* n. 175, at 3.
[226] *Id.* at 4.

trends are expected to continue.[227] Bloomberg New Energy Finance estimates that by 2030, the global power mix will evolve from today's system, in which two-thirds of our electricity comes from fossil fuel combustion, to one in which over half of all generation is produced by renewable resources.[228] And NREL has estimated that given today's commercially available technologies, "[r]enewable energy resources . . . could adequately supply 80% of total U.S. electricity generation in 2050 while balancing supply and demand at the hourly level."[229]

Markets for renewable energy certificates, which facilitate investment in renewable energy, are also well-established. Renewable energy has been traded for nearly two decades, during which time states have developed "integrated electronic tracking systems and standardized approaches to trading and establishing ownership of renewable energy."[230] RECs were used initially in the 1990s "as a means of accounting for energy procurement obligations like renewable portfolio standards (RPS), or power-source disclosure programs where load serving entities were required to inform their customers about the sources of electricity relied on to provide service."[231] Today, REC procurement is a common practice in states with mandatory RPS programs and with voluntary markets.[232] Federal and state agencies, ISOs and RTOs, and electricity market stakeholders rely on RECs to establish ownership and environmental attributes of those resources.[233] There are currently ten regional REC tracking systems in the country, which are used to demonstrate compliance with RPS programs.[234]

2. As Proposed, Building Block 3 Is Too Conservative and Must Be Strengthened.

In spite of the environmental benefits and increasing affordability of renewable energy, renewable energy resources remain largely untapped nationwide. According to estimates produced by the DOE's National Renewable Energy Laboratory, no state has achieved more than .01 percent of its technical potential for utility-scale solar energy (which includes both solar thermal stations and photovoltaic arrays).[235] Onshore wind generation has achieved greater market penetration, with five states exceeding ten percent of their technical potential

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[227] *Id.*

[228] Bloomberg New Energy Finance, *2030 Market Outlook: Global Overview*, http://bnef.folioshack.com/document/v71ve0nkrs8e0/who42hnkrs8fo (last visited Nov. 16, 2014).

[229] NREL, *Renewable Electricity Futures Study: Executive Summary* (2012), attached as **Ex. 24**, at 14.

[230] Quarrier & Farnsworth, Center for Resource Solutions/Regulatory Assistance Project, *Tracking Renewable Energy for the U.S. EPA's Clean Power Plan: Guidelines for States to Use Existing REC Tracking Systems to Comply with 111(d)* (June 25, 2014), attached as **Ex. 25**, at 3.

[231] *Id.* at 4.

[232] *Id.*

[233] *Id.*

[234] *Id.* at 5.

[235] These percentages were derived from data provided in the data file for EPA's *Technical Support Document: Alternative Renewable Energy (RE) Approach* ("*Alternative RE TSD*") (June 2014), *available at* http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-proposed-re-alternative-approach.xlsx.

and two states exceeding 25 percent.[236] However, a full 29 states have implemented less than one percent of their technical potential for onshore wind, and a full eleven states had no installed wind capacity at all as of 2012.[237] If the United States is to develop its renewable energy capacity at a level needed to avoid the worst effects of climate change, EPA must provide the proper regulatory drivers.

It is therefore not only appropriate but imperative that EPA include as one of the cornerstones of the Clean Power Plan increased generation from RE sources. However, both EPA's primary and alternate proposals for Building Block 3 will provide only minimal increases in RE generation nationwide beyond what can be expected in a business-as-usual ("BAU") scenario. EPA's proposals, with respect to renewable energy, do not reflect the best system of emission reduction, but rather the status quo system of emission reduction.

There are a number of ways in which EPA could modify Building Block 3 that would more appropriately reflect the best system of emissions reduction. EPA could correct several flaws in its RPS-based approach to setting the Building Block 3 targets, as described below. EPA could also refine its Alternative RE approach to update the cost and capacity assumptions used in the IPM modeling and eliminate the benchmark development rate cap that serves as an artificial cap on the RE potential of states. The Natural Resources Defense Council has undertaken IPM modeling using updated information, which yielded far higher RE targets that EPA should consider adopting.

Finally, EPA should consider a proposal by the Union of Concerned Scientists ("UCS") that reformulates the renewable energy components of Building Block 3 based on demonstrated growth rates of RE. The UCS approach approximately doubles the amount of generation nationwide from these resources by 2030 without incurring significantly greater costs. UCS released a report[238] on October 14, 2014 describing its proposal and will be submitting to EPA a separate set of comments that provide a comprehensive analysis of its proposal. We support UCS's demonstrated growth approach and offer several comments on it below.

Below, we discuss EPA's current proposals for assessing the BSER level of renewable energy potential for each state and then canvass the shortcomings of EPA's two approaches for RE. With respect to EPA's Alternative RE approach, we discuss improvements to the IPM modeling evaluated by NRDC. Next, we describe in more detail an alternative proposal, based on UCS's demonstrated growth approach, and explain how this RE model would avoid the shortcomings of EPA's two options. Finally, we directly address several of the questions posed in the preamble regarding RE.

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[236] *Id.*
[237] *Id.*
[238] *See* UCS, *supra* n. 183.

a. EPA's Current Proposals for Building Block 3

i. EPA's Primary Proposal

EPA's primary proposal for Building Block 3 is discussed in its Federal Register preamble at 79 Fed. Reg. 34,866-70 and is given comprehensive treatment in the agency's Clean Power Plan technical support documents. We therefore discuss these programs only in brief. For the purpose of setting RE targets, EPA's primary Block 3 proposal establishes six multi-state regions based primarily on North American Electric Reliability Corporation ("NERC") regions and Regional Transmission Organizations ("RTOs"). EPA then averages the 2020 RE percentage requirements in the renewable portfolio standards ("RPS") for the states in each region that have such programs and multiplies that average percentage by each region's 2012 baseline (i.e., the total electricity generation in the region in 2012). The resulting product is the 2030 regional RE target. EPA then calculates the annual percentage growth that the region would need to meet each year between 2017 and 2030 in order to meet its 2030 regional target (assuming that the region's total RE generation starting in 2017 is the same as its 2012 baseline). Each state is then expected to increase its RE generation each year between 2017 and 2030 according to the average growth factor in its region.

Notably, each state's expected RE generation is capped when it reaches what EPA has called its "maximum state target," expressed as the average 2020 RPS percentage for the state's region multiplied by the state's total generation in 2012.[239] So as not to confuse these limits with actual targets, we will refer to these as "maximum RE amounts." For example, in the Western region, which includes California, the regional growth factor is 6 percent annually.[240] If California begins its annual 6 percent increase in 2017, it hits its statewide target of 41,150,704 MWh in 2022, at which point its expected annual growth drops to zero. California's maximum RE amount represents the average RPS percentage requirement for 2020 in the Western states (21 percent) multiplied by California's total 2012 generation (approximately 200 million MWh). By contrast, another state in the Western region, Wyoming, has a maximum RE amount of approximately 10.2 million MWh, but applying the 6 percent regional growth factor between 2017 and 2030 yields only 9.4 million MWh of renewable generation in Wyoming. Hence, because the state is only expected to satisfy the regional growth requirements, rather than its maximum RE amount, it falls short of that maximum amount by some 800,000 MWh.

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[239] *See* EPA, *Technical Support Document: GHG Abatement Measures* ("*Abatement Measures TSD*"), No. EPA-HQ-OAR-2013-0602 (June 10, 2014), *available at* http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-ghg-abatement-measures, at 4-19 ("If, as the growth factor is applied annually, a state reaches an RE generation level that equals or exceeds the regional RE percent generation target, their RE generation target is made equal to the RE percent generation target as applied to that state's 2012 generation and is kept at that level for the remainder of the time period. If a state's RE generation in 2012 has already exceeded the regional RE target, their annual RE generation levels are held to the regional RE target for all years in the 2017-2029 time period.").

[240] For both the California and Wyoming examples, we used data provided in the *Proposed Renewable Energy (RE) Approach* data file for the *Abatement Measure TSD*, *available at* http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-proposed-re-approach.xlsx.

ii. EPA's Alternative Approach

EPA has also developed an alternative approach to Building Block 3 based on each state's technical and market potentials for RE development.[241] Under this approach, EPA would establish national benchmark development rates for different renewable technologies. To calculate these benchmarks, EPA establishes the development rate in each state for four types of RE resources by calculating the ratio of the state's actual generation from that resource compared to NREL's technical potential for that resource. The agency then averages the development rates for the 16 leading states for each technology to ascertain a national benchmark development rate for each technology, which is then applied to each state's technical potential. EPA also calculates an IPM-modeled market potential for each resource based on assumed cost reductions for the development of each resource. The state's target is then set based on whichever figure is lower—the national benchmark for a given resource as applied to that state or the IPM-modeled market potential.

iii. Shortcomings with EPA's Block 3 Approaches

EPA's current regional RPS-based approach for Building Block 3 falls short in several crucial regards. Most importantly, EPA's approach simply will not catalyze the investment in, and development of, renewable technology to the extent that it must. According to the agency's own estimates in its Regulatory Impact Analysis, the current proposal will increase generation from renewable sources by only 2 percent above BAU in 2030.[242] This does not meet the best system of emission reduction standard, but rather represents the status quo without taking into account any of the technological and market dynamics that will likely drive further RE development over and above current BAU forecasts.

3. Regional RPS Averages

One problem with EPA's approach is that it incorrectly assumes that averaging the RPS requirements of the states in a given region actually reflects the full level of RE investment that is reasonably achievable for that region. In fact, this is often far from the case. For example, the North Central region covers nine states—Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota, and Wisconsin—and has an average RE percentage requirement for 2020 of 15 percent, which is driven by the RPS requirements in five of these states: Illinois, Michigan, Minnesota, Missouri, and Wisconsin. Yet three of the four states that do not have RPS requirements—Iowa, North Dakota, and South Dakota—are among the nation's leading states in onshore wind development, generating approximately 25, 15, and 24 percent (respectively) of their total in-state electricity from wind in 2012. But because there are no RPS requirements in Iowa and the Dakotas, the RE target for the North Central region does not reflect the robust performance of wind-generated electricity in those states. While there is

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[241] *See* 79 Fed. Reg. at 34,869-70 and *Alternative RE TSD*.

[242] *See* RIA at Table 3-11.

some merit to EPA's view that RPS policies represent the judgment of state legislatures about what level of renewable energy development is feasible, this does not hold true for states without RPS policies, since zero RE is not a reasonable judgment as to the state's potential for economic RE.

As another example, the Southeast has the lowest average RE percentage requirement—only 10 percent—which is based on the RPS requirements of just one state: North Carolina. According to NREL's technical potential analysis, states in the Southeast region could generate over 30 million GWh annually from utility-scale solar stations.[243] Yet in 2012, these states generated just 348 GWh from solar plants, a tiny fraction of their technical potential and less than .04 percent of the total electricity generated in these states.[244] There are neither technological nor economic barriers to increased penetration of renewable resources in the Southeast market; rather, the problem is one of political will and inertia based on decades of reliance on fossil fuels. By relying on just a single state's RPS requirements to direct the renewable investment of nine states, EPA's approach largely entrenches the status quo rather than considering whether greater renewable penetration is achievable.

In calculating the regional target based on state RPS programs, EPA had to decide how to handle the facts that different states have targets set for different years and that not all states have 2030 targets. However, the way that EPA chose to deal with this was arbitrarily conservative. The agency derived a "2020 effective RE Level" for each state RPS, interpolating for those states without a specific target for 2020. It then established the average 2020 effective RE level for each region as the *2030* target for that region.[245] Thus, EPA effectively ignored the many state RPS goals for the years beyond 2020 that are more ambitious than the "effective 2020" targets. Even if one were to accept EPA's rationale that the judgment of state's legislature is a proper estimate of the full level of RE achievable in that state, there is no reason to take the states' average judgment about what level is achievable in *2020* and make that a *2030* target.

4. EPA Fails to Adequately Acknowledge State RE Potential

Another problem with EPA's current model for Block 3 is that it does not apportion renewable investment among the states in each region in a way that assures the "best" system. On the one hand, states are *not* expected to meet their maximum RE amounts by 2030. Rather, states are only expected to achieve the regional growth factor for each year between 2017 and 2030. To take one example,[246] Illinois's maximum RE amount for 2030 is about 29.9 million MWh; this figure represents 16 percent (i.e., the regional RE percentage in 2030 for the North

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[243] EPA, *Proposed Renewable Energy (RE) Approach* data file, *supra* n. 240.
[244] *Id*; *see also* EPA, *Abatement Measures TSD*, *supra* n. 239 (showing that these states generated a total of 986,000 GWh in 2012).
[245] *See Abatement Measures TSD* at 4-11.
[246] For the Illinois examples, we used data provided in the *Proposed Renewable Energy (RE) Approach* data file for the *Abatement Measures TSD*; *see* n. 240, *supra*.

Central Region) of the state's total 2012 generation. Yet Illinois is only expected to meet the North Central region's annual growth factor of 6 percent, which would yield just 17.8 million MWh of renewable generation by 2030, a figure 40 percent lower than Illinois's maximum RE amount.

On the other hand, states that meet their RE amounts before 2030 are not expected to produce additional renewable generation. For instance, North Dakota's[247] obligations to increase RE generation end in 2018, when it hits its maximum RE amount of 5.5 million MWh, whereas continued application of the 6 percent annual growth factor would double this figure by 2029. This effect is particularly dramatic for states like Iowa, whose 2012 generation from RE exceed their maximum RE amounts. Hence, even though Iowa produced 14.2 million MWh of renewable electricity in 2012, its 2030 RE target is just 8.6 million MWh. EPA has requested comment on whether the 2012 RE baseline should be considered a floor for renewable energy generation as part of Building Block 3 to address the situation just described in Iowa. 79 Fed. Reg. at 34,868. EPA's resolution of this issue depends on its final decision about how to credit renewable energy, which is discussed in further detail below. If EPA chooses to retain its preferred methodology of crediting each state with the renewable energy that it has "implemented," then the baseline RE should be recalculated to reflect that compliance criteria. On the other hand, if EPA credits a state with all of the renewable energy generation within its borders, then no state should be assumed to *lose* RE generation as part of its state target calculation.

Not only does EPA's approach truncate a state's RE growth before it reaches its maximum RE amount, it frequently cuts off a state's RE growth far short of the state's own RPS requirement. As Table 7 below indicates, for the substantial majority of states with enforceable RPS requirements (which are indicated in red), the Clean Power Plan sets targets that fall far short of those states' RPS obligations. States whose CPP target percentages are at or above their maximum RPS level are indicated in green. EPA's approach must, at a minimum, assume that states reach their own independently-set RPS targets.[248] Failing to account for states' existing RPS levels in establishing RE targets falls well short of meeting EPA's BSER obligation by effectively assuming, without offering any justification, that binding state laws will be violated.

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[247] *Id.*

[248] RPS programs sometimes allow for technologies to count as "renewable" that are not low-carbon, such as certain types of biomass, natural gas, or even "clean coal." To the extent that these technologies are part of the RPS structure at the state level and would not qualify as a low- or zero-carbon resource under EPA's proposal, there is justification for EPA's goals falling short of state RPS targets.

Table 7- Comparison of State RPS Targets and EPA Final RE Generation Targets[249]

State	2030 RE Percentage Under EPA's Plan	State RPS Target
Arizona	4%	15% (2025)
California	21%	33% (2020)
Colorado	21%	30% (2020)
Connecticut	9%	25% (2020)
Delaware	12%	25% (2027)
Hawaii	10%	40% (2030)
Illinois	9%	25% (2025)
Kansas	20%	20% (2020)
Maine	25%	40% (2017)
Maryland	16%	20% (2022)
Massachusetts	24%	33% (2030)
Michigan	7%	10% (2015)
Minnesota	15%	31.5% (2020)
Missouri	3%	15% (2021)
Montana	10%	15% (2015)
Nevada	18%	25% (2025)
New Hampshire	25%	25% (2025)
New Jersey	16%	24% (2021)
New Mexico	21%	20% (2020)
New York	18%	29% (2015)
North Carolina	10%	13% (2021)
Ohio	11%	13% (2024)
Oregon	21%	25% (2025)
Pennsylvania	16%	8% (2021)
Rhode Island	6%	16% (2019)
Washington	15%	15% (2020)
Wisconsin	11%	10% (2015)

The case of Hawaii illustrates several problems with EPA's approach. For both Alaska and Hawaii, EPA set 2030 regional targets based on the Southeast region, the lowest of the continental targets at 10 percent.[250] Thus, EPA's 2030 RE target for Hawaii is just 10 percent, despite the fact that as of 2012, renewable energy already made up 9 percent of Hawaii's retail sales.[251] EPA's target for Hawaii is also only one quarter of the state's own RPS target of 40

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[249] The data in this table derive from EPA's *Abatement Measures TSD*, Tables 4-2 and 4-8. Furthermore, Minnesota enacted a 1.5 percent solar energy minimum threshold, which is additive to the state's existing 30 percent RPS depicted in Table 4.2. *See* DSIRE, Minnesota, *Incentives/Policies for Renewables & Efficiency*, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MN14R (last visited Nov. 30, 2014).

[250] 79 Fed. Reg. at 34,867.

[251] See *Abatement Measures TSD* at Table 4-1.

percent by 2030. While EPA's instinct not to subject Hawaii to unreasonable targets based on its geographic isolation is understandable, the agency's approach to Hawaii completely ignores the state's strong historical RE growth and legally binding RPS targets.

5. EPA's Assumption that States Will Begin in 2017 with 2012 Levels of RE Generation Is Wrong.

In setting the state targets, EPA expects states to begin increasing their RE generation according to the regional growth factors starting in 2017, using each state's 2012 baseline as its 2017 generation level of RE. EPA states that this approach "assumes neither improvement nor decline in performance"[252] between 2012 and 2017, as though this assumption were perfectly neutral. In fact, this assumption is simply insupportable. As the agency accurately notes elsewhere, renewable energy generation is growing very quickly; in 2012 alone, installed wind capacity increased by nearly 28 percent and installed solar PV grew by over 83 percent.[253] There is no basis to assume that renewable energy generation will not grow tremendously between now and 2017. Setting the 2017 starting point five years behind RE growth under a BAU scenario is not consistent with EPA's obligation to rely on the best system of emission reduction. If the agency chooses to keep the basic framework of this approach, it must assume growth of RE generation at a rate of no less than 1 percent per year between 2012 and 2017. This recommendation is based on the demonstrated growth data compiled by UCS, which we discuss in detail below.[254]

a. Comments on EPA's Alternative Approach

EPA's alternative approach would not produce markedly different results from its primary approach in terms of nationwide renewable penetration. Excluding existing hydropower, the alternative approach would result in approximately 12 percent generation from renewable resources by 2030, the same result as the primary proposal. However, the two approaches produce rather different results from one region to the next: the alternative would generally achieve higher RE growth in the eastern states than the primary approach, lower growth in the central states, and similar growth in the western states.

Like its primary approach, EPA's alternative model for Block 3 has several significant shortcomings. For instance, EPA's IPM modeling assumes much higher prices for renewable generation going forward, and therefore underestimates the market potential for these technologies in the future. The Natural Resources Defense Council has developed alternative IPM runs using updated cost and capacity factor information for various renewable energy resources that show much higher levels of potential than EPA's IPM runs NRDC constructed "Updated Cost and Performance" runs of the IPM model using current levelized cost figures for

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[252] *Id.* at 4-17.
[253] *Id.* at 4-7 (citing DOE 2012 *Renewable Energy Data Book*).
[254] We also recommend below that EPA adjust the baseline RE levels and starting RE performance based on a state's "sponsored RE." *See infra* at 99-102.

wind and solar after finding that EPA's cost figures were 46 percent higher than the current average cost.[255] NRDC also increased the capacity factor of wind energy by 10 percent based on recent LBNL data, and reduced the capacity value of solar photovoltaic from 20 to 16 percent.[256] Finally, NRDC used lower and more current figures regarding the total cost of energy efficiency programs—ranging from 4.7 to 6.4 cents per kWh, and allowed the model to select as much energy efficiency as appropriate in the economically optimized generation mix.[257] Based on these refinements, the IPM model produced a total of 469 TWh of renewable generation nationwide in 2030, compared to EPA's 278 TWh.[258] The model also selected 609 TWhs of energy efficiency in 2030, compared to 469 TWhs in EPA's scenario. Moreover, the model generated *savings* over a business as usual scenario of $6.4-9.4 billion in 2030, compared to EPA's estimated *cost* of $7.3 and 8.8 billion.[259] While the level of increased RE generation is likely affected by the higher level of EE selected by IPM under NRDC's scenarios, using updated cost and capacity factor assumptions still yielded a 60 percent increase in 2020 RE generation over EPA's case, and a 44 percent increase for 2030.[260]

In addition to EPA's IPM inputs not reflecting current information, EPA's use of a technical potential benchmark to limit the IPM-derived economic potential is flawed. The IPM modeling is a sophisticated tool that dynamically accounts for cost and performance of different renewable technologies, and transmission and integration costs. By contrast, the technical potential benchmark rate is a somewhat crude metric that takes a single year of renewable energy development rates as a cap on future development, thereby ignoring widely forecasted improvements in the economics of renewable resources. It makes little sense to discard the superior IPM results based on lower estimates of potential from the technical potential benchmark, especially when EPA has relied on IPM results in many prior Clean Air Act rulemakings.

If EPA chooses to retain this feature of the Alternative RE model, it must update the NREL technical potential estimates that it uses, which do not reflect some of the recent developments in technology and engineering that will allow for greater renewable development. To provide one clear example, NREL's wind potential estimates are based on 80-foot wind maps, whereas new, taller turbine technology increases the potential in lower-wind

[255] Yeh, S., *NRDC Issue Brief: The EPA's Clean Power Plan Could Save Up to $9 Billion in 2030* (Nov. 2014), *available at* http://www.nrdc.org/air/pollution-standards/files/clean-power-plan-energy-savings-IB.pdf, at 1.
[256] *Id.* at 2, Table 1.
[257] *Id.* at 2. In contrast, EPA had represented energy efficiency in the model by reducing the load forecast by the amount of the state targets and had used costs of 8.5 to 9 cents per kWh.
[258] *Id.* at 1, Table 4. Results reported are for state-level compliance; NRDC also evaluated a regional compliance scenario that yielded slightly lower levels of RE generation in 2030.
[259] *Id.* at 2.
[260] *Id.* at 4.

areas.[261] The cost of solar energy has also declined significantly in the past several years, which is not reflected in the inputs EPA used.

Finally, because EPA's alternative methodology sums the potential across renewable energy technologies, it is hampered by the lack of data for specific technologies. For example, because the market potential for distributed generation cannot be tested with the current IPM framework, which only accounts for centralized generation, EPA omits the rapidly growing rooftop solar sector from its analysis.[262] The agency also omits offshore wind, despite its significant promise, because there are currently no operational offshore wind facilities from which to determine a baseline development rate.

In short, EPA's primary and alternative approaches to renewable energy do not adequately stimulate the market for these technologies. To be sure, these approaches are adequately demonstrated and provide reasonable expectations of what states can achieve in terms of both technology and economics. Yet section 111 requires the *best* system of emission reduction, and as we describe below, much more can be achieved in terms of renewable growth without significant cost impacts, and EPA must strengthen Block 3 accordingly.

b. The Demonstrated Growth Approach

i. An Overview of the Proposal

As noted above, we believe that the reformulation of Building Block 3 developed by the Union of Concerned Scientists is superior to either of EPA's approaches.[263] This approach includes three key features. First, the demonstrated growth rate approach is consistent with EPA's methodology for energy efficiency targets under Building Block 4 by setting benchmarks for incremental renewable energy growth in each state, ranging from 1.0 to 1.5 percent annually in total electricity sales. These benchmarks are based on demonstrated RE growth from 2009 to 2013, and states are expected to begin meeting their annual growth targets in 2017 (although the first year of compliance remains 2020). Second, the demonstrated growth approach assumes full compliance with enforceable RPS requirements in the states that have them, such that any state will be required to meet either its benchmark or the requirements in its RPS program, whichever is greater. Third, this proposal accounts for actual and expected RE development in the states between 2013 and 2017. Hence, the annual benchmark for a given state starting in 2017 applies the 1.0 to 1.5 percent incremental growth rate to the projected 2017 RE generation in that state. By contrast, EPA's approach relies on 2012 RE data as its starting point. Under the demonstrated growth model, RE generation is expected to reach 23 percent of total electricity sales nationwide by 2030 (not counting existing hydropower),

[261] *See, e.g.*, Southern Alliance for Clean Energy, *Low Wind Speed Case Study: Arkansas Wind Energy Resource* (Oct. 2014), attached as **Ex. 26**.
[262] *Alternative RE TSD* at 3.
[263] *See generally* UCS, *supra* n. 183. All of our subsequent description of the demonstrated growth approach references this document.

compared to 10 percent under business as usual and 12 percent under EPA's current formulation of Building Block 3.

To derive the annual growth targets for each state, UCS first examined EIA data from the most recent five years available (2009-2013) to determine the average growth rate of RE among the states. These data revealed that, on average, states increased their renewable share of electricity sales during this interval by 1.0 percent annually. The years between 2009 and 2013 are appropriate as a benchmark period for several reasons. First, these years represent the most recent demonstrated performance of renewable penetration into the electricity market, and thus provide a reasonable set of expectations for continued development. It accounts for the recent rapid growth in wind and solar technologies, but by averaging over five years also eases fluctuations in development due to uncertainty around federal tax credit expirations and extensions. Furthermore, the 2009-2013 interval captures much of the historic development spurred by state RPS policies—a key driver of RE growth as EPA has identified.

This proposal expects states whose annual RE growth was less than 1.0 percent during the benchmark period to begin scaling up their renewable development in 2017 until they meet the 1.0 percent annual growth rate by 2020 and continuing meeting that target each year until 2030. The fifteen states that met or exceeded the 1.0 percent growth in RE between 2009 and 2013 are expected to maintain their 2009-2013 average growth rate each year between 2017 and 2030 (or 2025, if EPA adopts a shorter compliance period), but in no case is a state expected to sustain a growth rate above 1.5 percent. For instance, Texas achieved a 1.1 percent annual growth rate in RE during the benchmark period and is expected to maintain that same growth rate from 2017 to 2025/2030.[264] North Dakota, on the other hand, which achieved an annual growth rate of 5.8 percent in 2009-2013, is expected to maintain RE growth at 1.5 percent annually from 2017 to 2025/2030. Furthermore, as indicated above, any state whose own RPS policies require greater RE development than application of our target growth rates is expected to meet the requirements of its RPS.

Finally, the baseline generation from which each state's RE growth begins is its projected RE generation in 2017, which is determined by adding projected generation from wind and utility-scale solar projects that will be under construction by 2016 to the actual RE generation data from 2013. This is far more realistic than EPA's counterfactual assumption of zero renewable energy generation growth between 2012 and 2017.

[264] UCS developed its state targets to sustain this growth through 2030, the end of EPA's proposed compliance period. As discussed in Section XIII.A, we believe that EPA should adopt a shorter compliance period and reevaluate its BSER determination after eight years, consistent with its review schedule for 111(b) standards for new sources. 42 U.S.C. § 7411(b)(1)(B).

ii. The Demonstrated Growth Approach Achieves Much Greater Renewable Energy Development than EPA's Proposals

The demonstrated growth model corrects flaws in EPA's proposals for Building Block 3 and enables the calculation of renewable energy targets that reflect BSER. As the figures on the following page illustrate, UCS estimates that a demonstrated growth approach would result in 23 percent renewable generation nationwide by 2030 compared to 12 percent under either of EPA's proposals, with improvements in every region of the country.

Fig. 22- Nationwide Renewable Percentages Under BAU, EPA's Primary Approach, and the Demonstrated Growth Approach[265]

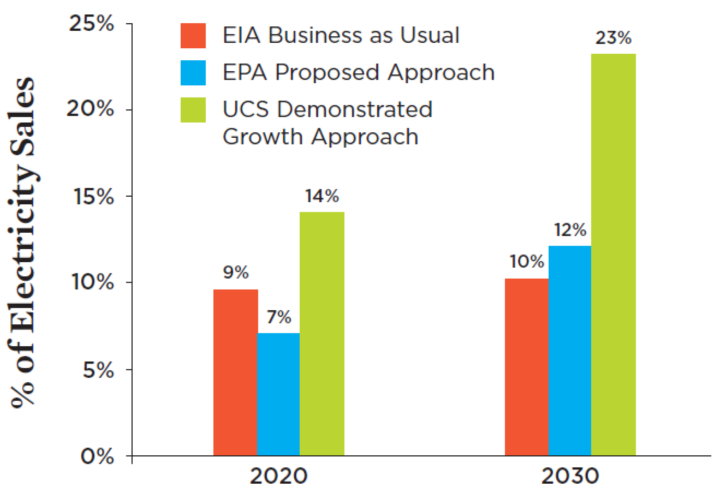
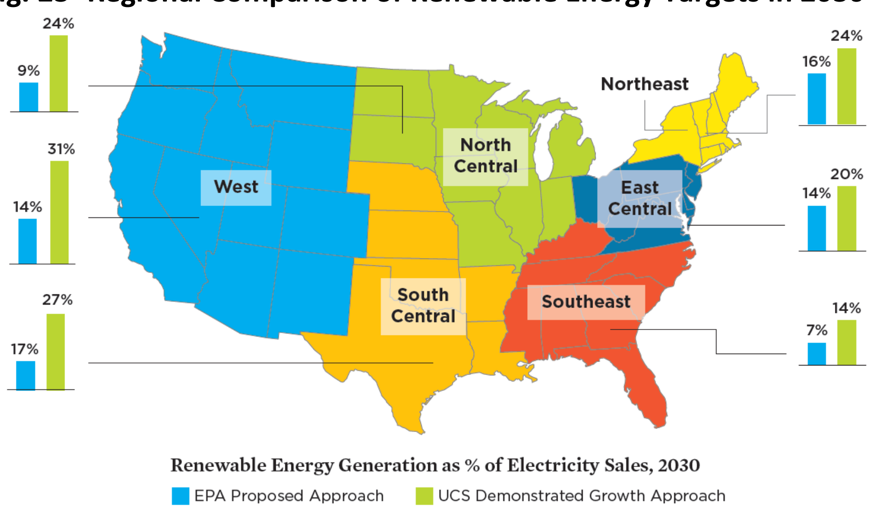


Fig. 23- Regional Comparison of Renewable Energy Targets in 2030[266]



[265] UCS, *supra* n. 183, at 3.
[266] *Id.* at 5.

It is worth emphasizing that the figures above assume that no state will be required to increase its RE generation above 40 percent of all in-state electricity sales.[267] Under the demonstrated growth approach, only nine states will reach 40 percent, and only eleven will meet or exceed 35 percent renewable energy generation. With the exception of the single-state region of Hawaii, which will hit the 40 percent ceiling, overall RE generation in any of the regions designated under EPA's plan will not approach 40 percent.

Although the UCS approach includes this ceiling on RE growth, we believe that states with strong renewable resource profiles can meet and exceed 40 percent by 2030, and grid operators' own evaluations show that they can already manage high levels of RE generation. A study for PJM completed in March 2014 indicates that "with adequate transmission expansion and additional regulating reserves, [it] will not have any significant issues operating with up to 30% of its energy provided by wind and solar generation."[268] Additionally, an ongoing, multi-phase NREL study has found that up to 35 percent renewable energy can be integrated into the Western Interconnection without the need for extensive infrastructure changes; instead, better forecasting, broader coordination, and improved operating practices will allow for integration.[269] Indeed, Germany—the most populous, industrialized, and economically robust country in Europe—already produces 30 percent of its electricity from renewable resources and is on target to hit 40 percent by or before 2030, an extremely rapid increase over its 6.3 percent rate in 2000. Should EPA adopt a demonstrated growth approach, the 40 percent ceiling proposed by UCS is not unreasonable, even while it may be unnecessary. Furthermore, if the agency selects a compliance period ending in 2025, as we advocate, the issue becomes moot, since no state would hit 40 percent by that year under our proposed approach in any event.

In addition to doubling the amount of renewables expected by 2030, the demonstrated growth approach has several other advantages over EPA's approach. First, unlike the EPA proposal, the demonstrated growth model accounts for distributed generation ("DG"). DG has shown exceptional growth in recent year: for instance, UCS reports that the number of rooftop solar installations grew by an average of more than 50 percent per year between 2008 and 2013.[270] The price of a typical household system dropped by almost 30 percent between 2010 and 2013, even while the capacity of such systems across the United States more than tripled in that time.[271] DG also represents one of the most significant areas for growth of renewable electricity in the coming years. According to a recent study published by Navigant Research,

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[267] Our discussion of the UCS approach in this paragraph references data included in the spreadsheet entitled *UCS RE Building Block State-Level Data*, attached as **Appendix 3**.

[268] GE Energy Consulting, *PJM Renewable Integration Study*: *Executive Summary Report* (Mar. 31, 2014),, at 6-7. 30 percent renewable was the highest level of renewable energy studied.

[269] *See, e.g.,* Lew & Brinkman, NREL, *The Western Wind and Solar Integration Study Phase 2: Executive Summary*, NREL/TP-5500-58798 (Sept. 2013), *available at* http://www.nrel.gov/docs/fy13osti/58798.pdf. For more discussion on renewable integration, *see* Section XI.A5.

[270] Rogers & Wisland, UCS, *Solar Power on the Rise: The Technologies and Policies Behind a Booming Energy Sector* (Aug. 2014), attached as **Ex. 27**, at 1.

[271] *Id.*

worldwide revenue from DG is expected to grow from $97 billion in 2014 to more than $182 billion by 2023.[272]

Second, the demonstrated growth approach expects that states with RPS targets will *at least* meet those targets. EPA's approach sets targets for many states that fall short of their legally enforceable RPS targets, even though it uses those RPS requirements as the basis for its regional targets. Third, and relatedly, while EPA's plan effectively forces laggard states to begin making progress on RE development, it imposes few (and in some cases no) additional obligations on states with excellent and highly economic renewable energy resources that have already shown leadership in developing those resources. The UCS approach would require *all* states to continue developing renewable resources at an historically appropriate rate. Finally, the demonstrated growth approach is based on what states have actually been achieving in recent years, whereas EPA's model looks instead to what state legislatures and environmental agencies have decided is politically expedient. EPA's formulation of the best system of emission reduction must be based on empirical evidence about what is possible within the electrical system at reasonable cost, and the UCS approach amply satisfies this standard.

iii. The Demonstrated Growth Approach is Adequately Demonstrated and Economically Reasonable

A demonstrated growth approach to renewable development is a proper element of BSER not only because it will achieve significant CO_2 reductions at affected EGUs, but because it is both adequately demonstrated and economically reasonable as well. The very name of this proposal is testament to that fact: it is based on rates of RE growth that have actually been demonstrated nationwide in the last five years, and simply expects that states can and will continue to develop their renewable resource portfolios at the same rate going forward. Notably, 11 of the 15 leading states that have achieved growth rates at or above the national benchmark of 1.0 percent growth from 2009 to 2013 have achieved that same rate or higher over a 10-year period, from 2004 to 2013, indicating that the national benchmark rate already has been shown to be sustainable over relatively long periods.

The growth during the 2009-2013 period reflects not only support from state renewable energy incentives, but also from the federal government through the production tax credit ("PTC") and the investment tax credit ("ITC"). While the PTC has been an important policy for supporting wind energy development, there has been uncertainty each year regarding its renewal, which has tempered its impact on wind energy growth. Should the current PTC be eliminated, there will likely be a period of adjustment that will at least temporarily result in reduced installation rates. However, wind energy is an increasingly competitive product, as seen through the recent levelized cost data cited above, and the wind industry will likely adopt financial mechanisms (such as yield cos and master limited partnerships) to replace its historical

[272] Press Release, Navigant, Revenue from Distributed Generation is On Pace to Surpass $182 Billion by 2023 (Sept. 4, 2014), *available at* http://www.navigantresearch.com/newsroom/revenue-from-distributed-generation-is-on-pace-to-surpass-182-billion-by-2023.

reliance on tax equity financing. We strongly support a certain and robust PTC at current levels in order to facilitate maximum clean energy development. But even in the event of a reduced or discontinued tax credit, we believe wind energy will be a pivotal tool to meet the standards laid out in the CPP. Moreover, solar energy is growing at a very fast rate and will be close to grid parity soon (supra); thus, solar energy technologies can be expected to fill in if wind development slows. Indeed, in a recent analysis by the Electric Reliability Council of Texas ("ERCOT"), the independent system operator found that solar would dominate the renewable energy added to the system in a Clean Power Plan compliance scenario, with 12.5 GW of solar added by 2029.[273] Indeed, even under a baseline scenario without the Clean Power Plan, ERCOT anticipated that twice as much solar would be installed as new natural gas plants.[274] While Texas has relatively high solar insolation, it has lagged in development of its solar energy resources compared to other states with less solar insolation that have already seen high levels of solar growth thanks to robust incentive programs, such as Massachusetts, New Jersey, and New York.[275] Considering that EPA's renewable energy targets for states are well below their technical potential for solar energy development, solar energy will be a valuable complement to wind energy in helping all states reach their targets.

Taking all of these factors together, combined with the tremendous incentive that the Clean Power Plan itself will create, it is wholly reasonable to expect the leading states to continue developing renewable resources at a rate that comports with their recent performance, and to ask non-leading states simply to begin meeting the national average of RE growth over the last five years.

In spite of the fact that NREL's state-by-state technical potentials for different renewable technologies are outdated at this point and underestimate the general potential from various sources (such as taller wind turbines), these figures nevertheless represent reasonable estimates of the maximum renewable generation that can be achieved in each state. If each state were required to meet the demonstrated growth targets described above, it would realize no more than a tiny fraction of its overall NREL-designated technical potential. UCS has conducted a regional analysis and has determined that the West, North Central, and South Central regions would all achieve just 0.2 percent of their technical potentials for RE development via the demonstrated growth approach, and the Southeast, East Central, and

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[273] ERCOT, *Analysis of the Impacts of the Clean Power Plan* (Nov. 17, 2014), at Table 3 (Capacity Additions by 2029).

[274] While ERCOT used EIA AEO 2014 forecasts of the capital costs for most generation technologies, it found that solar capital costs were declining much more rapidly than indicated by EIA based on information from Lazard, a confidential report by Greentech Media and Solar Energy Industries Association, and another confidential report by Citi Research. *See* ERCOT, *supra* n. 273, at 4, nn.3-5. ERCOT estimates that solar capital costs will decline from just under $2500 per kW in 2014 to under $1500 in 2029—a 40 percent decline.

[275] *See* SEIA, *State Rankings by Q2 2014 PV Installations*, http://www.seia.org/research-resources/solar-industry-data (last visited Nov. 26, 2014).

Northeast regions would hit 0.5, 1.6, and 2.2 percent, respectively.[276] A regulatory program that expects only such a small percentage of the RE development that is technically achievable according to the federal government's best estimates is easily feasible and adequately demonstrated under section 111 of the Clean Air Act.

As far as costs go, UCS conservatively estimates that the demonstrated growth approach would have only a marginal increase in electricity prices above EPA's proposal. Using NREL's Renewable Energy Deployment System ("ReEDS") model, UCS found that its proposal would achieve a nationwide average of 23 percent of electricity sales from RE while increasing average retail electricity prices nationwide by no more than 0.3 percent annually through 2030 (with some regional variation).[277] Decreased reliance on natural gas under an aggressive RE scenario would in turn yield savings both in the electricity and gas sectors. Given that consumers will feel little to no noticeable effect in the cost of electricity under the UCS approach, there is every reason to believe that utilities in both regulated and restructured states will easily absorb the regulatory costs of this proposal. In regulated states, utilities will continue to receive guaranteed returns on prudent capital expenditures, while utilities in market-based systems will pass on minor costs to consumers without significant reductions in demand. Section 111 merely requires that a BSER not impose "exorbitant" costs that would cripple the regulated industry, and the additive costs of UCS's demonstrated growth approach are far from exorbitant, whether considered by themselves or in conjunction with the overall regulatory design of the Clean Power Plan.

One reason for the modest costs of the demonstrated growth approach is scaling effects. That is, the more widespread a particular technology or method of generation becomes, the less costly it is to produce, install, and operate. This can result from traditional economies of scale, reductions in administrative burdens and other "soft costs" due to increased public support for the technology, and "next-of-a-kind vs. first-of-a-kind"-type benefits. DOE's SunShot initiative aims for a 75 percent reduction in the cost of solar generation by 2020 by funding innovative technology development and reducing soft costs.[278] As of 2014, DOE is already 60 percent of the way toward achieving this goal.[279] Several studies have shown that rooftop solar installations in Germany, which has been a leading proponent of DG, are considerably cheaper than they are in the United States, due in large part to more efficient installation practices, reduced administrative costs, and other practical strategies.[280] The figure

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[276] UCS, *UCS Approach for Strengthening the Renewable Targets in EPA's Clean Power Plan* (Oct. 2014), attached as **Ex. 28**, at 14.

[277] UCS, *supra* n. 276, at 5.

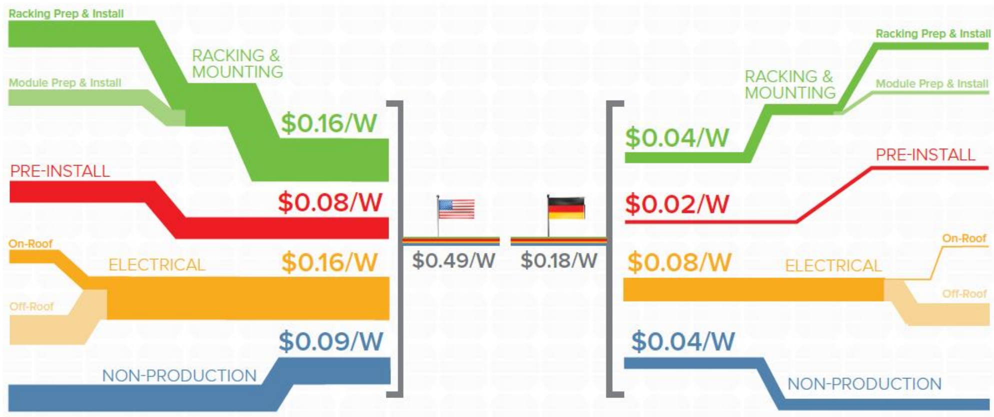
[278] *See* DOE, *SunShot Initiative Mission Statement*, http://energy.gov/eere/sunshot/mission (last visited Nov. 16, 2014).

[279] *Id.*

[280] *See, e.g.*, Rocky Mountain Institute/Georgia Tech Research Institute, *Reducing Solar PV Soft Costs: A Focus on Installation Labor* (Dec. 2013), attached as **Ex. 29**; Solar Freedom Now, *A Roadmap for Reducing Rooftop Solar Costs by 50%: Less Paperwork = More Solar* (March 2013), *available at* http://www.climateactionprogramme.org/images/uploads/documents/Reducing_Rooftop_Solar_Costs.pdf.

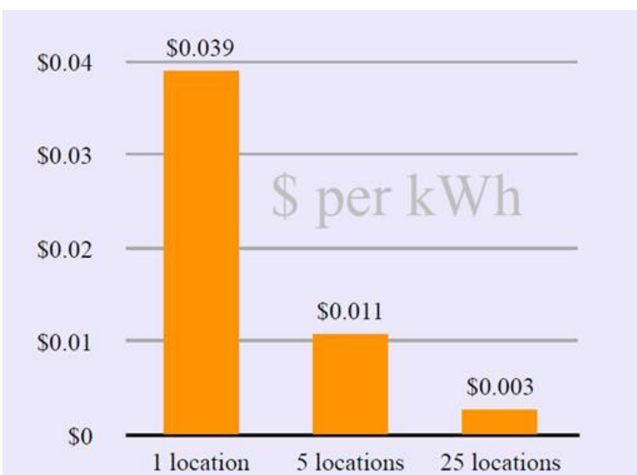
below, reproduced from a report authored by the Rocky Mountain Institute and the Georgia Tech Research Institute, compares the cost of installing rooftop solar arrays in Germany versus the United States, and illustrates the cost savings that can be achieved through more efficient installation techniques.

Fig. 24- Cost Comparison for Rooftop Solar Installations- U.S. vs. Germany[281]



An additional feature of renewable energy is that the system integration costs decrease as these resources become more dispersed due to system-wide reductions in the variability of generation. While an individual renewable source has variability of generation, a larger pool of such resources distributed across a broad geographic area (such as a metropolitan region) have less variability and require lower backup or ancillary services costs. The following chart, adapted from an NREL study, depicts the relationship between backup costs and the dispersion of utility-scale solar plants:

Fig. 25- Backup Costs and the Dispersion of Solar Facilities[282]



[281] Rocky Mountain Inst. and Georgia Tech. Research Inst., *supra* n. 280, at 5.
[282] Farrell, *Democratizing the Electricity System: A Vision for the 21st Century Grid* (June 2011), attached as **Ex. 30**, at 21.

This issue is discussed further in the reliability section of our comments; *see infra*, Section XI.

As these studies indicate, the demonstrated growth approach is likely to incur fewer backup costs than current predictions suggest as a result of scaling effects and reduced backup costs from greater dispersion of renewables. Additionally, the experience in Germany makes clear that ample opportunities exist to reduce renewable costs by adhering to more efficient protocols and reducing administrative hurdles. Because the demonstrated growth is both economically reasonable and adequately demonstrated, it is an appropriate component of BSER for the Clean Power Plan.

Thus, a demonstrated growth approach will achieve significantly greater development of renewable energy at little added cost by either 2025 or 2030, depending on the length of the compliance period. We strongly urge EPA to adopt this approach or one similar in order to maximize the role that clean energy will play in reducing CO_2 emissions from our electricity sector. However, if EPA nevertheless decides to retain the basic approach it laid out in its rule proposal, EPA should make the changes discussed above to comply with the BSER mandate in the Clean Air Act.

6. Comments on EPA's Specific Issues for Building Block 3

In addition to these recommendations, we address two issues for which EPA requested comment in its preamble. First, EPA asks what role hydropower should play in Building Block 3. *See* 79 Fed. Reg. at 34,869. We agree with EPA's decision not to include existing hydropower in Building Block 3, since opportunities for increased generation from this resource are very limited in comparison to other renewable technologies. However, the agency asks whether new hydropower electricity (either newly constructed projects or increased generation from existing projects) should count toward compliance. *Id.* We believe that there are promising opportunities to increase electricity generation at existing facilities, unpowered dams, and run-of-river projects.[283] These types of technologies already qualify under many state RPSs that do not allow existing hydropower to count towards compliance.[284]

Second, EPA asks whether "the difference between a state's RE generation target and its 2012 level of corresponding RE generation does not exceed the state's reported 2012 fossil

[283] *See generally* DOE, *An Assessment of Energy Potential at Non-Powered Dams in the United States* (Apr. 2012), *available at* http://www1.eere.energy.gov/water/pdfs/npd_report.pdf.
[284] *See* DOE, DSIRE, *Washington Renewable Energy Standard*, www.dsireusa.org (last visited Nov. 30, 2014) (allowing post-1999 incremental hydropower that does not involve new diversions or impoundments to count towards compliance); Oregon Dep't of Energy, Oregon's Renewable Portfolio Standards: Hydropower in the Oregon RPS (July 2013), *available at* http://www.oregon.gov/energy/RENEW/docs/Hydroelectricity%20and%20the%20Oregon%20RPS%20Fact%20Sheet.pdf,(detailing limitations on use of existing hydropower capacity).

fuel-fired generation." *Id.* at 34,868-69. This issue only affects Washington, whose 2012 fossil generation (9.4 million MWh) is less than the amount of new generation from renewables the state would produce if it met its RE generation target under Block 3(15.9 million MWh). We see no reason to limit the amount of new RE expected of Washington based on its 2012 fossil generation. That strategy might make sense if EPA's plan supposed that each and every new MWh from RE were to replace a MWh from an existing fossil unit, but that is not the case: at least some of that new RE generation will meet demand growth rather than displace existing fossil generation. Washington also imports some power from neighboring states, much of which is from fossil generating units.[285] And even if that additional 15.9 million MWh of clean energy were to displace all fossil-fired generation *and* exceed the state's demand growth, Washington could sell any additional clean electricity to nearby states, such as Montana and Wyoming, which lack strong renewable industries. Finally, it is worth noting that under EPA's current plan, Washington is not expected to actually meet its state RE target, but need only meet the regional growth factor. As such, Block 3 only expects Washington generate an additional 9.5 million MWh from RE, which is only marginally higher than its 2012 fossil generation of 9.4 million MWh. If the agency decides to retain its proposal for Block 3, we urge it to require all states to meet their RPS targets, as noted above, rather than simply the regional growth factors.

Finally, EPA has requested comment on whether it should adjust the way it has incorporated Building Blocks 3 and 4 into the BSER calculation. *See* 79 Fed. Reg. at 64,547-48. In incorporating Building Block 2, EPA reduced the dispatch (and emissions from) all steam EGUs based on the amount of increased generation by natural gas combined cycle units. EPA reduced the dispatch of coal and oil & gas steam units proportionately. However, EPA did not reduce the dispatch of any fossil unit based on increased generation by renewable energy resources, or decreased load resulting from increased demand-side energy efficiency. Instead, EPA simply added the megawatt-hours of RE and EE savings to the denominator of the emission rate. The result is target emission rates that do not reflect reality in any way, and are higher than they would be if reduced dispatch was incorporated.

We support EPA's proposed revision to the goal computation methodology. In reality, fossil EGUs will dispatch less when load is reduced, and when low-cost, must-take renewable energy generation is available. The combination of adding RE and EE to the denominator of the rate and reducing emissions from fossil units results in a lower rate overall. How much the rate declines is highly sensitive to what assumptions EPA makes about which fossil units are displaced. If EPA's emission rate targets do not include this effect, then they will be artificially high (less stringent). Thus, a state could actually do less in all building block categories than EPA anticipates, and still reach its target. This possibility reveals that the emission rate does not properly reflect the best rate of emission reduction.

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[285] *See* Washington Dep't of Commerce, *Washington State Electric Utility Fuel Mix Disclosure Reports for Calendar Year 2012* (July 2013) at 13 (Avista utility purchase of 950,000 MWh from Montana's Colstrip coal plant), 238 (Puget Sound Energy purchase of 3.7 million MWh from Colstrip).

EPA seeks comment on the assumptions it should make in displacing fossil generation in the emission rate. EPA proposes several options, including: proportional displacement of all fossil, displacement of highest-emitting units first, or displacement of coal-fired EGUs first. Consistent with our comments regarding EPA's methodology for displacement of steam EGUs under Block 2, we believe that EPA should first remove from the formula the generation by the highest-emitting units, which are typically coal-fired. This environmental dispatch constraint will yield the lowest target and is therefore the best system of emission reduction.
We recognize that EPA's proposed rule would allow states to take credit for renewable energy generation attributable to measures in the state's plan even when it does not result in displacement of in-state EGUs. Likewise, we have advocated that EPA allow states to take credit for energy efficiency savings directly attributable to their EE programs, regardless of where the emission reductions actually occur. Once fossil displacement is factored into the state's target, the state will have some incentive to design RE and EE measures in a way that causes displacement of in-state high-emitting units, so that the state also receives that emission reduction benefit. Designing RE and EE measures in a way that avoids the need for operation of baseload coal-fired plants will also reduce the difference between the environmental dispatch required to implement the rule, and economic dispatch practices.

7. Compliance and Enforcement Considerations Under Block 3

Above, we discussed how EPA's inclusion of RE as a component of BSER is well-supported by the tremendous growth of the renewable sector, states' increasing enactment of renewable portfolio standards and similar policies, and the demonstrated emission reductions associated with RE generation. EPA has highlighted in the Preamble and State Plans TSD several unique compliance issues that arise with renewable energy, which we will address in this section. These issues are as follows: First, how can renewable energy generation be credited towards the state and compliance entity's emission rate in a way that is quantifiable and verifiable? Second, how should EPA and the states address conflicts created by the interstate nature of renewable energy so as to ensure that emission reductions claimed by each state and compliance entity are non-duplicative? Finally, which of the resources typically thought to fall into the category of "renewable energy" are appropriate as compliance measures?

a. Crediting Renewable Energy and Energy Efficiency Towards the Emission Rate

Both renewable energy and energy efficiency reduce the need for operation of affected EGUs in order to meet the economy's electricity requirements. EPA has requested comment on how these zero-carbon MWs and avoided MWhs should factor into a state or source's emission rate. 79 Fed. Reg. at 34,919. This issue fits within the framework of how RE and EE meet the "quantifiable" requirement for an emission standard. We believe that it is important that the mechanism for factoring these resources into the state or source's rate[286] be straightforward

[286] Throughout this section, we refer to the emission rate of a "state or source." As discussed above, we believe that enforceable responsibility to fully achieve the rate should fall on the owners and operators of affected sources. Therefore, it is most technically appropriate to understand which source takes

and allow states and sources to readily forecast the compliance payoff of specific EE and RE policies. Any methodology that is highly resource-intensive or uncertain will discourage states from making RE and EE a significant part of their plans and will favor increased natural gas redispatch and new gas construction. We believe that the only time a state needs to specifically identify the fossil EGU displaced by renewable energy is to avoid double-counting across rate-based and mass-based states.

EPA proposes two options for crediting RE and EE: the avoided MWh approach and the avoided CO_2 approach. Under the "avoided MWh" approach, whatever unit or state is taking credit for the renewable energy generation will add those MWhs to the denominator of its emission rate. Under the "avoided CO_2" approach, the amount of avoided CO_2 emissions attributable to the renewable energy is calculated based on one of a variety of methodologies that EPA has described, and that value is then subtracted from the numerator of the unit's or state's emission rate. For example, EPA has suggested that the avoided CO_2 emissions could be based on the average or marginal emission rate of the power pool or region in which the renewable energy was generated, system dispatch modeling, or tools such as AVERT.[287] Under the avoided CO_2 approach, a MWh of RE or EE that displaces higher-emitting affected EGUs would contribute more to a state or compliance entity's efforts to reach its targets.[288]

While both approaches have merit, we believe that the avoided MWh approach is preferable for several reasons. First, the avoided MWh approach is consistent with how EPA has calculated the targets for both Building Blocks 3 and 4. Maintaining a consistent methodology across target-setting, plan development, and compliance demonstration will provide states and sources with greater certainty about how to incorporate renewable energy and energy efficiency into their plans. Switching to a different methodology for compliance might mean that even if a state enacted an RPS at the level of the 2030 RE target identified by EPA, that RPS might not have the impact EPA has anticipated on the state's emission rate.

Second, the avoided MWh approach allows states to predict with much more certainty the impact of their renewable energy and energy efficiency measures on their plan performance demonstration. The avoided CO_2 approach requires a calculation of the CO_2 emissions avoided by each MWh generated from a renewable resource both prospectively (during plan development) and retrospectively (when assessing plan performance). EPA has proposed a range of methodologies for estimating avoided CO_2, ranging from the relatively

credit for renewable energy and will be able to adjust its rate accordingly. However, in the sense that states will be responsible for developing plans and implementing policies to foster renewable energy development, it is also accurate in certain contexts to speak of a state as taking credit and making adjustments to the state emission rate.

[287] *See* EPA, *State Plans Considerations TSD ("SPC TSD")*, Docket ID No. EPA-HQ-OAR-2013-0602 (June 2014), *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf, at 22-23.

[288] The methodology for accounting for RE and EE, discussed in this section, is distinct from how direct emissions of carbon dioxide from affected sources will be measured.

simple power pool average to more complicated modeling of dispatch planning and capacity expansion.[289] These methodologies are in use for various purposes and were discussed in EPA's *Roadmap for Incorporating EE/RE Policies and Programs into State and Tribal Implementation Plans*.[290] EPA has also taken important steps in recent years to support the development of new tools, such as AVERT, to aid in converting avoided MWhs to avoided carbon emissions.

The accuracy of these methodologies for identifying the displaced fossil fuel unit increases with their complexity and the resources required to execute them properly. However, no methodology is 100 percent accurate, especially on the longer time horizons involved in the Clean Power Plan, which will require states to forecast power system dynamics 14 years out. In 2030, and in yearly July 1 filings from 2020 to 2030, states will be required to compare actual emission performance with the projections in their state plans. 79 Fed. Reg. at 34,907. The actual fossil EGUs displaced, and therefore the actual tons of CO_2 avoided, may differ significantly due to unanticipated factors like new or retiring generation, generation or transmission outages, unexpected changes in load, or unusual weather. *Id.* at 34,907. In contrast, an avoided MWh approach allows a state to implement a policy designed to bring about a certain level of renewable energy generation and remain confident that if that policy works properly, the state will be on track to meet its goals.

The use of an avoided MWh approach will also be more transparent to the public and to EPA. If system dispatch and capacity planning models are used as part of plan development and performance evaluations, stakeholders seeking to review the plan or assess the state's compliance will have to procure expensive licenses to work with these models. While accurate accounting of actual CO_2 reductions attributable to specific EE/RE measures would be helpful, it is not necessary to satisfy the "quantifiable" requirement for emission standards under Section 111(d). Quantification of MWhs alone, and treatment of those MWhs as zero-carbon generation that is part of the overall system, satisfies this condition.[291] We believe that EPA should, where possible, streamline the methodology for states to incorporate renewable

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[289] *Id.* at 24-32. EPA's EE/RE Roadmap suggests that projections of the impacts of RE and EE policies extending more than five years require more sophisticated tools to understand how generation and the transmission system will change over time. *See* EPA, *Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix I: Methods for Quantifying Energy Efficiency and Renewable Energy Emission Reductions*, EPA-456/D-12-001j (July 2012), at I-32. Thus, while EPA offers a number of simplified methodologies, it appears that the ten year compliance period, combined with a four year gap between state plan development and beginning of the compliance period, will require capacity expansion modeling, in addition to system dispatch. This increases greatly the expertise and resources need to develop the state plans, and the difficulties for stakeholders and EPA staff in reviewing the proprietary model inputs and outputs.

[290] *See* EPA, *EE/RE Roadmap Manual*, http://epa.gov/airquality/eere/manual.html (last visited Nov. 17, 2014).

[291] Konschnik & Peskoe, Harvard Law School, Environmental Law Program- Policy Initiative, *Efficiency Rules: The Case for End-Use Energy Efficiency Programs in the Section 111(d) Rule for Existing Power Plants* (Mar. 3, 2014), attached as **Ex. 31**, at 11-14.

energy into their plans. The one instance in which it is necessary to identify the unit displaced by renewable energy or energy efficiency is if that unit may be subject to a mass limitation, which could give rise to double-counting if not addressed. This situation is discussed further below.

If EPA were to require states to use dispatch modeling to forecast emission reductions, there could be another practical barrier to estimating avoided CO_2 from renewable energy with substantial accuracy. Dispatch modeling requires information on the day and time the renewable energy was generated or the MWh was saved. However, existing REC tracking systems, which are likely to be a central part of compliance with the CPP, do not maintain information on the day and time that an RE megawatt hour was generated.[292] Generation profiles from different types of renewable energy resources are available to assess the likelihood that a particular MWh was generated during a certain hour, which could allow for better estimates of the displaced unit. Likewise, most energy efficiency program administrators do not gather information on when a particular renewable energy measure is actually saving energy on the system, though estimates can be developed based on the type of energy efficiency measure.[293] For example, more efficient air conditioners can produce savings primarily during the hottest hours of a summer day, whereas CFL or LED lightbulbs will produce more savings evenings and in the darker winter months. While we believe that these sorts of tools for estimating the timing of EE savings or RE production are well-demonstrated and reliable, they add further layers of complexity to the avoided CO_2 approach.

In contrast, most state RE and EE targets are either already designed around MWh targets or are based on percentage of load, which can be readily converted to MWhs. In most states, the officials implementing these programs have limited experience or lack tools to convert those MWh savings to avoided CO_2 emissions. While these challenges can be overcome, we believe there is benefit in maintaining a metric with which state regulators are familiar and for which implementation is less resource-intensive and more certain.

The avoided CO_2 approach does, however, have some advantages. This approach is fundamentally more accurate in calculating how much CO_2 is being reduced through RE and EE measures. In contrast, the avoided MWh approach simply credits the MWh of renewable energy with the average emission rate of the state's affected EGUs (for assessing adequacy of the state's plan), or the emission rate of whichever affected EGU happens to acquire the RE

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[292] Most REC systems track only the month and year of generation, while the ERCOT system makes available only the quarter and year. *See* **Appendix 4**. States must also be careful to note the date of generation, not the date that the certificate was issued, which sometimes lags the time of generation. *Id.*

[293] *See* Shenot, J,, Regulatory Assistance Project, *Quantifying the Air Quality Impacts of Energy Efficiency Policies and Programs* (Aug. 2013), *available at* http://www.raponline.org/document/download/id/6680%E2%80%8E; Shenot, J., Regulatory Assistance Project, *Calculating Avoided Emissions Should be a Standard Part of EM&V and Potential Studies*, ACEEE 2014 Summer Study Paper (Aug. 2014), *available at* https://www.aceee.org/files/proceedings/2014/data/papers/8-192.pdf, at 8-372 to 8-373.

credit (for compliance purposes). Under the avoided CO_2 approach, not every MWh of RE or EE is equivalent—those that displace higher-emitting affected EGUs would be more valuable to states and compliance entities. Thus, there would be an incentive for states and compliance entities to design RE and EE measures that achieved the greatest reductions in carbon emissions.[294] In the interest of curbing carbon at the lowest possible cost, applying the avoided CO_2 method would help generate better information about which RE and EE measures are most effective at reducing carbon emissions.

In conclusion, while both the avoided MWh approach and the avoided CO_2 approach could be part of a quantifiable and verifiable emission standard for RE and EE, we believe that the avoided MWh approach would be less expensive and complicated for state agencies to implement, and also for stakeholders and EPA to review. For these reason, we primarily endorse the avoided MWh approach while still acknowledging the benefits of the avoided CO_2 approach.

b. The Interstate Nature of Renewable Energy and Energy Efficiency

With few exceptions, the electricity market is not constrained by state lines. However, renewable energy is distinct in that states have enacted policies that stimulate development of renewable energy in other states to serve the enacting state's load. Because so many state RPSs allow out-of-state renewable energy resources to count towards compliance, and because so much renewable energy in fact crosses state lines pursuant to these policies, EPA has properly recognized a particular need to address the interstate aspect of renewable energy.

There are two key aspects of the interstate renewable energy issue that EPA should address in the final rule and concurrent guidance. The first question is which state or source should be permitted to include the renewable energy generation in its adjusted emission rate (more informally, which state or source gets "credit"). The second question is how to avoid double-counting when renewable energy is generated in one state, but the actual energy or associated credit is transferred into another state.

i. Which State or Source Gets Credit for Renewable Energy Generation?

As EPA notes, renewable energy generation has strong interstate characteristics. RE may be generated in one state and sold to purchasers in a different state, all the while displacing an affected EGU in yet a third state. States that have implemented renewable portfolio standards in most circumstances impose no restrictions on the geographic location of the RE resources that their utilities use to meet those standards. Other state policies to promote renewable energy development, such as production tax incentives or property tax exemptions, apply by

[294] The negative view of this potential is that states and compliance entities could manipulate their chosen models to forecast higher avoided CO_2 than would actually occur, which would lead to fewer carbon emission reductions overall.

design to resources built within state borders, regardless of where the electricity generated by those resources ultimately flows.

EPA has put forward two methods for determining which state receives credit for renewable energy generation. EPA's primary proposal is that "a state could take into account all of the CO_2 emission reductions from renewable energy measures implemented by the state, whether they occur in the state or in other states." 79 Fed. Reg. at 34,922. According to EPA, "this proposed approach for RE acknowledges the existence of RECs that allow for interstate trading of RE attributes and the fact that a given state's RPS requirements often allow for the use of qualifying RE located in another state to be used to comply with the state's RPS." *Id.*

EPA's alternative proposal is that states can take credit only for emission reductions occurring within the state as a result of its renewable energy policies. *See id.* In other words, the renewable energy measures must cause displacement of in-state affected EGUs in order to be included in the state's compliance showing. EPA's proposal also recognizes that multi-state platforms obviate much of the need to allocate renewable energy to particular states. *Id.*
For the reasons discussed below, we support EPA's primary proposal but believes that significant clarification is needed regarding the underlying principles to provide states with sufficient guidance about what renewable energy generation they will be able to count in their plans and compliance showings.

8. States and Affected EGUs Should Get Credit for All Renewable Energy Generation Regardless of Where Units Are Displaced.

We believe that states should be able to take credit for emission reductions that occur out of state so long as reductions will not be double-counted by states reporting on achieved plan performance. In the next section, we offer suggestions as to what demonstration states should make with respect to double-counting. Here, we discuss why it is important for states to receive credit for emission reductions in other states that result from the implementing state's policies. The primary reason to we advocate this approach is that it is consistent with existing practices and will promote efficient development of the nation's renewable energy resources.

As EPA notes, most existing state renewable energy policies, specifically RPS programs, allow utilities to count renewable energy generation that occurs in other states. These policies are also generally not concerned with whether the renewable energy procured displaces in-state resources. In adopting this stance, state legislatures have recognized that energy is an interstate commodity and that limiting RE procurement to in-state resources could prevent utilities from seeking the least-cost renewable energy options that may be available. Indeed, limiting utilities to in-state renewable resources could increase the cost of compliance with the rule, at least in the short run. Limiting states to in-state resources would also prevent any state from taking credit for generation by offshore wind facilities in federal waters, even if a utility purchases the generation and RECs from that wind resource. Such a limitation would also fail to make the optimal use of existing transmission system resources. RE projects should be located where the best renewable energy resources are, and where available transmission capacity facilitates moving the generation to load. Attempting to locate RE resources where they will cause reduced dispatch of a particular EGU is difficult and not likely to lead to the least-cost option.

As noted above, there are many factors that can affect where generation from fossil EGUs will be displaced by renewable energy generation: the displaced unit can vary from season-to-season and from hour-to-hour, depending on load characteristics, outages at other generators, and transmission system limitations. It would be highly resource intensive for states to forecast the extent to which a particular renewable energy project will actually reduce in-state emissions.[295] If a state could only take credit for RE generation that displaced in-state units, unanticipated new generation or retirements over the ten-year compliance period could change which fossil unit is displaced by RE generation, such that a wind farm for which a state could previously take credit is later no longer available to the state as a compliance measure. This uncertainty would make it less likely for a state to include significant RE measures as part of its plan in comparison to measures that would carry less uncertainty, such as increased gas dispatch of existing NGCCs. EPA's proposed policy of allowing states to take credit for renewable energy regardless of where displacement occurs will minimize this uncertainty and promote the use of RE in state plans.

Finally, EPA's proposal properly rewards states that implement strong RE policies, rather than states that happen to have high renewable energy potential or states with marginal units less likely to be dispatched under a high-renewable scenario. It is far easier for states to design policies that will incentivize a certain amount of RE generation than to anticipate exactly which EGUs are displaced by that renewable energy. Likewise, affected EGUs that are subject to enforcement under this rule may purchase renewable energy credits or otherwise promote the development of renewable energy; to also require that this RE displace emitting generation in a specific location is too high a hurdle and may hinder the efficient development of these resources.

We do note that there is a potential difference between the options for establishing RE potential for the purpose of goal setting and how EPA will determine compliance. In target setting, EPA set the baseline for each state based on the amount of renewable energy generation physically occurring in a state.[296] EPA then calculated a current RE performance level by dividing in-state RE generation by total in-state generation to yield a percentage.[297] EPA's methodology does not account for whether that renewable energy had been "implemented" by the state, or whether the RECs corresponding to that generation are held in-state. Thus, some states may have a higher or lower baseline of RE generation and RE performance level than they would be able to report for compliance purposes today.

[295] The same is true for displacement caused by energy efficiency savings, which are discussed further below.
[296] *See Abatement Measures TSD* at 5 (noting the 2012 net generation by state).
[297] *Id.*

Our proposed solution is to apply the UCS recommended percentage targets using the amount of creditable RE in a state. Should EPA finalize its proposed approach that states can take credit for renewable energy that they have implemented, as we recommend, EPA may also want to consider modifying how the baseline RE generation and the starting RE performance level is determined for each state. As an alternative to setting the baseline based on current in-state RE generation, EPA could require states, working with their utilities and affected EGUs, to undertake an accounting of what renewable energy generation they would be able to take credit for under EPA's rule as of the date they submit their state plan. This would most often be in-state RE generation less RECs "owned" by out-of-state persons and plus any RECs generated out-of-state but owned by in-state persons. We refer to this as the state's "sponsored renewable energy." The "denominator" for determining the starting RE performance level and target level of performance would be the overall consumption of electricity in the state in the starting and compliance year(s).[298] This is similar to and consistent with our proposal for Block 4 set out below.

State targets would then increase from the sponsored RE baseline and RE performance level according to whichever methodology EPA settles on for Building Block 3. This approach would allow states that currently export a lot of renewable energy, such as North Dakota and Iowa, to establish a more accurate baseline. Likewise, it would ensure that states which import large amounts of renewable energy start at a higher RE baseline and are not allowed to backslide or remain stagnant during the early years of the plan performance period. While auditing the state's current level of sponsored RE would be a significant undertaking, states will already need to do this in order to design a state plan that achieves their RE targets.

By undertaking this process at the outset of plan development, EPA will have an opportunity to resolve at the outset questions about how states will allocate credit for projects with multiple sources of policy support. In designing their plans, states would have greater certainty about how different renewable energy policies will work within their plans. This undertaking will also serve as an opportunity for EPA to test the sufficiency of the existing REC trading systems for compiling this type of information, allowing any needed refinements to those systems to be made in time for the plan performance period.

a. EPA Must Clarify How Different Types of Renewable Energy Policies and Measures Can Receive Credit for Generation Across State Lines.

As noted above, EPA proposes that "a state could take into account all of the CO_2 emission reductions from renewable energy measures implemented by the state, whether they

[298] EPA states in the *Abatement Measures TSD* at pp. 4-5 that "[c]onsistent with the design of a number RPS policies, RE "performance" is measured here as the share of total generation." We note that many RPS policies are expressed as a percentage of a load-serving entities retail sales, as opposed to in-state generation.

occur in the state or in other states." 79 Fed. Reg. at 34,922.[299] The agency further lists a number of different policies that states could implement to promote renewable energy and use for compliance purposes. These includes RPSs, direct incentive programs, production and property tax incentives, workforce training subsidies, and research and development funding, to name a few.[300] Many utility-scale renewable energy projects make use of multiple state and national programs in order to successfully finance a project. EPA states that "production-based tax incentives have been among the most important incentives used by states and utilities to help achieve RPS requirements, as well as to spur additional production and use of renewable energy."[301]

For example, the developer of a wind farm in state A could sign a power purchase agreement with a load-serving utility in state B, which the State B utility will use for compliance with state B's RPS. However, the wind farm might also receive production tax credits from state A. Both state A and state B's policies played some role in making the state A wind farm economically viable, or in "implementing" that wind farm, to use EPA's terminology. Under the proposed rule, both states would have some claim to credit for the generation from this wind farm.

EPA should provide guidance to states for assessing the relative contribution of different state policies to a particular renewable energy project.[302] For example, the credit could be apportioned based on financial analysis of the contributions of each state's policy to the viability of a renewable energy project; or, credit could go solely to the holder of the renewable energy credit associated with generation from that wind farm. While some states may work out these problems among themselves through multi-state accounting agreements, some form of guidance or default allocations would provide more certainty for states, utilities, and renewable energy developers. We encourage EPA to further develop and describe what it means for a state to have "implemented" a renewable energy measure in light of the interactive nature of state and federal policies promoting clean energy.

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[299] EPA defines "renewable energy measure" to mean both renewable energy requirements and incentives, and individual installed RE systems. *SPC TSD* at 60 n.85. This broad definition complicates the interpretation of what it means to "implement" a measure.

[300] *SPC TSD* at 60-61.

[301] *Id.* at 61.

[302] EPA states at one point that if the "renewable energy generation resulting from production-based tax incentives [is] used for RPS compliance . . . then it should not be counted separately in a state plan from MWh generation used to comply with a state RPS." *Id.* at 72. While we agree that the full MWh generation from a project should not be counted under the production-based tax incentive and under the RPS, it is not necessarily the case that the RPS has the better claim to the generation. This is especially important where the RPS is the policy of a different state than the tax incentive, as in the example above.

9. EPA Should Make Clear What Role RECs Will Play in State Plan Consideration and Compliance.

EPA's proposed rule makes several references to renewable energy credits ("RECs"), but never comprehensively describes the function they may serve in compliance. RECs will likely play a key role in how states and utilities claim credit for renewable energy generation and how they will avoid double-counting.

RECs are currently traded on nine exchanges across the country.[303] Each REC represents one MWh of generation and is tracked within the exchange by a unique serial number along with information such as the year of generation, the type of RE resource generating the REC, and the location where generation occurred. These exchanges represent to buyers that each REC is unique and therefore serve the purpose of verifying and auditing REC generators. RECs are sold both to utilities seeking to show compliance with a state RPS and also into the "voluntary" market, which comprises businesses and other private entities wishing to increase the sustainability of their operations or make green power claims. The voluntary market currently comprises a little less than half of the total market for RECs in the United States.

In general, ownership of RECs is negotiated as a private contractual matter between an RE generator and the purchaser of the output. RECs can be sold either bundled with the underlying energy or unbundled. In the latter case, the renewable energy is on paper stripped of any zero-carbon or zero-pollutant characteristics and referred to as null energy. To avoid double-counting, it is essential that if one compliance entity claims ownership of a REC, the corresponding null energy not be used for another entity's compliance demonstration. Bundled RECs reduce this risk, since the recipient of the electricity and the REC holder are the same entity. Many PPAs involve the sale of bundled RECs, meaning that the PPA price covers both the REC and the delivered energy.

However, some RE purchases and policies do not involve the transfer of RECs. For example, some renewable energy generators sell electricity into wholesale markets rather than to a particular generator through a PPA. This is true, for instance, of wind farms in the ERCOT regions of Texas. These farms do not sell bundled RECs, since there is no identified purchaser of their electricity. Instead, their RECs are sold on the exchanges as unbundled credits to purchasers who want RECs for either compliance or voluntary purposes.

Unbundled RECs are also generated from distributed generation when the utility to which the resource is interconnected has elected not to purchase the REC. For example, the Public Utilities Regulatory Policy Act ("PURPA") requires utilities to purchase the output from small renewable energy generators, called qualifying facilities ("QFs"). However, the Federal Energy Regulatory Commission ("FERC") has held that a sale of this nature does not necessarily

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[303] *See* Quarrier & David Farnsworth, *supra* n. 230.

encompass any RECs; instead, whether the RECs transfer to the utility is left up to state law.[304] Thus, RECs generated by a QF do not always transfer to the utility, even though the utility purchases the power.[305] These RECs could then be sold on the REC exchanges, creating a possible double-counting situation if the interconnected utility seeks to take credit for this null power.

Likewise, many net metering customers are not required to transfer the RECs generated by their systems to the utility.[306] Thus, while the state's net metering policy or related incentives could be viewed as "implementing" some amount of rooftop solar development, the utility might not hold the RECs that have been generated, which may even have been transferred to an out-of-state third party. However, utilities could quantify and verify the distributed generation on their system through a mechanism other than RECs, so long as no other state claimed 111(d) credit for a REC from a particular distributed generation source. Compliance issues with distributed generation are discussed further below.

Most federal or state legislation that provides financial incentives for the development of renewable energy is silent about the ownership of associated RECs.[307] RE projects that receive state financial incentives often retain the associated RECs rather than transfer them (or a portion thereof) to the incentive program administrator.[308] This is in part because the state's objective is to allow renewable energy projects to maximize other revenue sources, such as REC sales, so that state subsidies can eventually be reduced. It is also because RECs have historically had little value to state incentive program administrators. States might have difficulty claiming credit under the Clean Power Plan for these kinds of RE policies if RECs become viewed as the sine qua non of entitlement to RE credit. States thus need guidance on whether they will able to claim credit for tax incentives and other financial assistance programs if they do not require RE generators to transfer their RECs as a condition of receiving financial assistance.

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[304] *Morgantown Energy Assocs.*, "Notice of Intent Not to Act and Declaratory Order," 139 FERC ¶ 61,066 (Apr. 24, 2012).

[305] For example, a recent order by the Utah Public Service Commission held that because the price paid to QFs represents only energy and capacity value, and not the renewable attributes, the QFs retains the RECs and may sell them on a registry. PacifiCorp Large Renewable QF Avoided Costs, Docket No. 12-035-100, Order on Phase II Issues, Aug. 16, 2013.

[306] Distributed generation should be eligible for compliance only if EPA's target setting methodology includes distributed generation. UCS's demonstrated growth approach does include distributed generation, and since we support that alternative, we offer comments on how DG can be accounted for in compliance.

[307] A study done on behalf of LBNL in 2006 surveys REC ownership relating to various state renewable energy policies. Holt, et al., Ernest Orland Lawrence Berkeley Nat'l Lab., *Who Owns Renewable Energy Certificates? An Exploration of Policy Options and Practice*, LBNL-59965 (Apr. 2006), *available at* http://emp.lbl.gov/sites/all/files/REPORT%20lbnl%20-%2059965.pdf.

[308] *Id.*

In the absence of a new nationwide tracking service for RE generation, the existing REC system will be heavily used by states and sources seeking to demonstrate compliance. This presents several issues, summarized below, which EPA should anticipate and offer guidance on:

- Must states offering tax incentives or other financial assistance obtain a portion of the RECs from projects they fund in order to claim any credit under the CPP?
- Over 50 percent of the RECs currently sold through exchanges are entered into the voluntary market. If this trend continues, this represents 50 percent of the current renewable energy generating capacity that may not be available for CPP compliance.
- If EPA requires states to adjust their emission rate based on avoided CO_2 emissions, more precise information about the time and location of generation will be needed than is currently tracked in the REC systems. Most exchanges currently track only the month of generation. This is not detailed enough information to use in a dispatch model or AVERT to estimate avoided CO_2 emissions, as EPA has suggested it might require.
- REC trading systems should track the date of commercial operation of a particular renewable energy resource to allow states and EPA to assess whether the RE generation comes from a resource eligible for compliance. Likewise, REC trading systems must provide sufficient detail about the type of renewable energy resource that generated the electricity in order to allow states and EPA to assess whether it is an eligible compliance resource. This will be necessary if EPA allows only some biomass or hydropower resources to be eligible, for example, or if states choose to limit the kinds of resources that qualify as renewable in their plans.

a. Double-Counting

EPA has asked whether its proposed approach to interstate allocation of renewable energy presents double-counting concerns, and what states must show to demonstrate that no other state has claimed credit for the same renewable energy generation. There are two aspects of the double-counting question. The first is whether the MWhs of renewable energy will be included in the adjusted emission rate for more than one source or state. The second is whether the fact that displacement of affected units occur in one state, while credit for that renewable energy is taken by another state, constitutes a form of double-counting.

10. How Can Multiple States Be Prevented From Taking Credit for the Same MWh of Renewable Energy?

We believe that existing REC trading systems are the most promising mechanism to avoid double-counting of renewable energy generation. These systems assign unique identifiers to each MWh of generation and have well-established protocols for verification.

Because the nature of REC tracking systems is to ensure that each MWh is claimed only once, RECs are a natural tool to be adapted for use in the Clean Power Plan to avoid double-counting of renewable energy. For each compliance demonstration period, a state or compliance entity would have to submit a list of REC serial numbers that it holds for the compliance year in question, and verify that to its knowledge, no other state or compliance entity is claiming credit for that same REC. REC system operators should collaborate to make available a unified web-based tool available to stakeholders and EPA to verify the origin and trading history of a particular REC using the serial number.

If any state or compliance entity seeking credit for renewable energy generation must produce a REC, there is almost no risk of direct double-counting. Making RECs the sole currency for including RE generation in a state or utility's compliance plan does, however, as discussed above, require changes to existing state policies to effect transfers of RECs or negotiation among states about REC ownership from RE projects that have benefitted from multiple states' policies.

EPA should also assess what type of verification measures each of the REC tracking systems has in place. For example, EPA should gather and make available data on how the system operator verifies the claims of generators, how often meters must be tested, whether generators are subject to occasional inspection, and other means of ensuring the accuracy of the RECs generated and preventing fraud. EPA may also want to consider requiring REC system operators to undergo initial and periodic audits. None of these suggestions should be taken to indicate distrust of the validity of existing REC systems, but rather that EPA should exercise due diligence in understanding and, if necessary, strengthening the safeguards built into these systems which will factor heavily into CPP compliance.

If EPA determines that existing REC verification procedures are not adequate to ensure accuracy and avoid fraud, it should work with the RE generators and REC tracking system operators to bring those procedures up to standard. In the meantime, EPA must not allow RECs generated through such systems to count towards CPP compliance. This can be ensured by requiring the REC tracking system operator to add a field to the system indicating whether the REC meets EPA's data quality standards.

11. Displacement of Fossil Fuel EGUs and Related Double-Counting Issues

Every MWh of renewable energy generation leads to one fewer MWh of generation by a higher cost generating unit, typically a fossil fuel plant.[309] The unit displaced is the one with the highest marginal operating cost, setting aside transmission constraints and other operational constraints such as ramp rates. Due to the interstate nature of the electrical system, the generating unit displaced by RE will not always be in the same state that implemented the RE measure, or the same state where the RE is physically located.

[309] This equivalence does not account for the small difference in line losses depending on the proximity of each resource to load.

When an affected EGU is displaced due to RE generation, this reduces the mass emissions from that unit, but does not reduce that unit's emission rate. Unless the unit takes credit for the RE generation by adding it the denominator (or subtracting avoided CO_2 from the numerator), the reduced dispatch alone does not help that unit meet its emission rate target. Therefore, there is no double-counting in a state with rate-based targets if the entity taking credit for RE generation does not also operate the displaced EGU.

At the state level, there are some modest effects on the overall emission rate due to this displacement, but they can be positive, negative, or neutral, depending on which unit is displaced. If a coal plant in one state is displaced by renewable energy that is credited to another state, the first state's emission rate will go down slightly, all else being equal, since more efficient natural gas combined cycle combustion will then make up a larger percentage of the generation factored into the rate in comparison to coal.[310] If a natural gas combined cycle plant is displaced, the state's emission rate could actually go up slightly if the aggregated emissions rate of the remaining resources is higher than that of the displaced gas plant. EPA's current proposal, which we advise against, is to exclude peaking plants from the BSER rate. If EPA retains that approach, then the displacement of a simple cycle peaking turbine by renewable energy will have no effect on the state's emission rate from displacement alone.

The possibility that an affected unit is displaced in a state different than the state that takes credit for the renewable energy generation may be seen to raise concerns about double-counting. We understand that there may be both displaced generation and the creation of RECs, but we do not consider this to be double-counting. So long as all states involved in the scenario employ rate-based plans, there are no double-counting concerns. Similarly, if any state within the same ISO or RTO has adopted a mass-based system, there will be no double-counting of renewable energy so long as EPA adopts the annual true-up procedures we recommend for mass-based targets; *see* Section VI.A.2, *infra*.

12. Eligible Renewable Energy Compliance Resources

A wide variety of energy-producing technologies are sometimes characterized as "renewable" under various state laws. EPA must clarify that these technologies will qualify for Clean Power Plan compliance as a "renewable energy resources" only if they emit zero carbon dioxide. Because EPA's methodology for crediting renewable energy involves either adding RE MWhs to the denominator of the emission rate or subtracting the emissions avoided at a displaced fossil EGU from the numerator, it would not be appropriate for EPA to allow states to credit in this way purportedly renewable resources that generate carbon emissions. Specifically, EPA should exclude from its definition of renewable resources technologies such as "clean" coal, waste coal, combustion of municipal solid waste and pulping process byproducts (black

[310] However, many states have emission targets that are below the emission rate of a typical NGCC unit. In these states, it will be of little assistance toward achieving the target if the state's affected gas plants make up a larger fraction of the overall covered emissions after a coal unit is displaced by renewable generation.

liquor), and biomass-generated fuels.[311] To implement this limitation, EPA should require REC tracking systems to add a field verifying whether a particular RE resources is eligible for CPP compliance. REC tracking systems already contain fields to track eligibility for particular state RPS requirements, so should have no difficulty adding such a field for the CPP once provided with a definition by EPA.

Below, we offer further comments regarding why biomass should be excluded as a renewable energy technology. We also discuss EPA's treatment of hydroelectric resources and distributed generation technology.

a. Biomass

EPA has proposed that, although biomass fueling of EGUs is not included as part of BSER,[312] it would be an eligible measure for reducing CO_2 emissions from EGUs. EPA seeks comment on whether measures to increase the use of biomass-derived fuels at affected EGUs would be appropriate to include in a state plan to achieve CO_2 emission reductions from affected EGUs. 79 Fed. Reg. at 34,923. We do not believe that biomass combustion should count as a low-carbon generating resource.

At the EGU, burning biomass generates more CO_2 emissions than even coal combustion. A 2011 analysis by the Partnership for Policy Integrity found that wood combustion generates 213 lbs CO_2/MMBtu, compared to 205.3 lbs CO_2/MMBtu for bituminous coal.[313] Utility-scale biomass boilers are also only about 25 percent efficient, which is lower than either average coal or gas boilers.[314] Likewise, co-firing of biomass with coal decreases a facility's overall efficiency.[315] Therefore, when considering only carbon emissions at the stack, biomass is far

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[311] If EPA agrees that such technologies should be excluded as compliance measures, then it should also exclude those technologies from its target setting process.

[312] While EPA does not separately focus on biomass as part of its BSER determination, most states identify biomass as an eligible renewable energy resource for the purpose of their renewable portfolio standards. However, despite this, only 0.16 percent of the electricity generated in the United States comes from biomass-fueled units. *See* EIA, *Biomass for Electricity Generation*, http://www.eia.gov/oiaf/analysispaper/biomass/ (last visited Nov. 19, 2014); EIA, Electric Power Monthly with Data for August 2014 (Oct. 2014), *available at* http://www.eia.gov/electricity/monthly/pdf/epm.pdf.

[313] Partnership for Policy Integrity ("PFPI"), *Carbon Emissions from burning biomass for energy*, http://www.pfpi.net/carbon-emissions (last visited Nov. 30, 2014). PFPI refers to EIA 1605 data for natural gas and coal, and emission information for wood biomass comes from ORNL's Bioenergy Feedstock Development Programs.

[314] *Id.* (citing data from EIA and air permit reviews). *See also* Georgia Pub. Serv. Comm'n, *Georgia Power Plant Mitchell Unit 3 Biomass Conversion Cancellation: Decision Review Findings* (June 5, 2014) (noting Georgia Power testimony that converting from coal to biomass firing would increase the facility heat rate).

[315] *See* Elec. Power Research Inst., *Biomass Cofiring Update 2002: Final Report*, No. 1004319 (July 2003).

from a low-carbon energy source and should not be allowed as a zero- or low-emitting resource eligible as a Building Block 3 compliance measure.

The claims made in favor of biomass as a low-carbon energy resource depend on the life-cycle carbon balance of biomass combustion, namely that the growing of biomass materials sequesters carbon from the atmosphere, rendering it a carbon-neutral fuel. EPA is very familiar with the controversy over whether biomass-derived fuels can be considered carbon-neutral.[316] A panel of the independent Scientific Advisory Board released an assessment in 2012 of EPA's proposal for accounting for carbon emissions from biomass combustion within the greenhouse gas PSD permitting program,[317] and EPA is currently revising its guidance for PSD permitting of biomass combustion.

However, it would be inconsistent with the overall framework of the Clean Power Plan for EPA to account for the life-cycle carbon emissions of biomass-derived fuels. The agency has not looked at the life-cycle carbon impacts of other fuels, but rather only at the stack emissions from coal- and gas-fired units. If EPA were to allow biomass to be treated as a low-carbon emission source, that would amount to a backdoor carbon offset scheme, which EPA has otherwise prohibited.[318] Furthermore, if the agency were to grant biomass status as a low-carbon resource based on life-cycle impacts, it would then also have to factor in the life-cycle carbon impacts of coal and gas production.

Even if EPA were to look beyond stack emissions, the case for biomass as a low-carbon fuel is unclear and highly dependent on the sourcing and processing of the fuel.[319] Biomass-derived fuels have low energy value relative to fossil fuels, and transportation and processing of large quantities of the biomass can negate any carbon benefits the fuel might provide. In addition, even where commitments are made to sustainably source biomass, such as using only agricultural waste products, compliance with these commitments must be carefully monitored to ensure that non-sustainable fuel crop biomass is not used if the primary supply runs low.

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[316] See *Deferral for CO_2 Emissions from Bioenergy and Other Biogenic Sources Under the Prevention of Significant Deterioration (PSD) and Title V Programs* ("Deferral Rule"), 76 Fed. Reg. 43,490, 43,493 (July 20, 2011); EPA, Office of Air and Radiation, Office of Atmospheric Programs, Climate Change Div., *Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources* (Nov. 2014).

[317] EPA Science Advisory Board ("SAB"), *SAB Review of EPA's Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources*, EPA-SAB-12-011 (September 28, 2012).

[318] *See* PFPI, *The Role of Biomass Energy in EPA's Greenhouse Gas Rule* (July 1, 2014), *available at* http://pfpi.net/wp-content/uploads/2014/08/PFPI-GHG-rule-writeup-August-7.pdf, at 14 (citing Projecting EGU CO_2 Emission Performance in State Plans TSD at 37: "For emission budget trading programs that regulate EGUs and include offsets, which we define here as emissions reductions from sources not regulated by the trading program, emissions reductions from offsets would not be counted when evaluating CO_2 emission performance of affected EGUs, because those reductions would not come from those affected EGUs.").

[319] See *id.*; Manomet Center for Conservation Sciences, *Biomass Sustainability and Carbon Policy Study* (June 2010), conducted for the Massachusetts Dep't of Energy Res., *available at* http://www.mass.gov/eea/docs/doer/renewables/biomass/manomet-biomass-report-full-hirez.pdf.

Finally, the time scale over which biomass resources sequester carbon is far slower than the rate at which carbon is emitted during combustion, rendering biomass a poor strategy for reducing atmospheric carbon levels in the coming decades. For these reasons, we believe that the carbon benefits of biomass fuels are too unreliable for these fuels to be part of a state's compliance strategy.

However, if EPA determines otherwise, it must provide guidance about how to calculate the overall carbon emissions associated with biomass production and combustion, a task already underway at the agency. EPA cannot assume, as it has stated in the proposed rule, that "broadly speaking, burning biomass-derived fuels for energy recovery can yield climate benefits as compared to burning conventional fossil fuels." 79 Fed. Reg. 34,924. Any estimate of carbon emission reduction will be highly dependent on the source of the biomass and the conditions of its combustion, and EPA must establish standards for monitoring these factors which states must follow if seeking to use biomass as part of the plan. EPA recently released its Revised Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources, which will undergo further review by the SAB.[320] If EPA intends to apply this framework to the Clean Power Plan, we believe there should be an opportunity to submit additional public comments on that issue.

b. Hydropower

We support the omission of existing hydropower resources from the 2012 renewable energy baseline due to the distortions that it would cause in the northwest region's renewable energy baseline. Alternatively, as EPA suggests in its NODA, if annual growth factors were calculated based on state-level rather than regional-level data, the potential for large amounts of hydropower in Washington, Oregon, and Idaho would not affect the growth factors for other states within the western region. As neither Washington nor Oregon allow most existing hydropower to be counted towards compliance with the state's RPS, it would be somewhat contradictory for EPA to include hydropower in those states' renewable energy baselines. Finally, omitting hydropower from the baseline avoids creating further incentive for these states to retain unnecessary and ecologically disruptive dams.

As is the case in Washington and Oregon, it is common for RPSs throughout the country to exclude large existing or new hydropower. A 2013 report by the Clean Energy States Alliance surveyed hydropower provisions in state RPSs and noted that many disqualify older dams, those larger than 30 MW, or the technology used (impoundment versus run-of-river).[321] These exclusions reflect both an awareness of the adverse impacts of large hydropower and a desire to stimulate the growth of new RE resources.

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[320] *See* EPA, *Carbon Dioxide Emissions Associated with Bioenergy and Other Biogenic Sources*, http://epa.gov/climatechange/downloads/Framework-for-Assessing-Biogenic-CO2-Emissions.pdf (last updated Nov. 21, 2014).

[321] Stori, Val, Clean Energy States Alliance, *Environmental Rules For Hydropower In State Renewable Portfolio Standards* (Apr. 2013), *available at* http://www.cesa.org/assets/2013-Files/RPS/Environmental-Rules-for-Hydropower-in-State-RPS-April-2013-final-v2.pdf.

We agree that future development of certain hydropower resources, including non-powered dams not appropriate for removal and well-designed run-of river-resources, can provide low-cost baseload renewable energy, and should be available to states and compliance entities. We do not support all new hydropower development, especially large projects that disrupt hydrological systems, destroy habitat and jeopardize protected species. However, we do not believe that it is within the scope of this rule for EPA to impose limits on which hydropower resources should be available for compliance, other than excluding existing hydropower as it has proposed.

c. Distributed Generation

Distributed solar generation ("DG") is a major area of renewable energy growth in the United States.[322] EPA correctly recognizes that feed-in tariffs and net metering are policies that promote distributed generation, and could be used as compliance measures.[323] However, EPA must include this resource in its target-setting and provide further guidance on this issue especially with respect to customer-sited DG. First, EPA should clarify that load-serving utilities should not receive credit for all DG interconnected with its system, but rather must have in place a policy that incentivizes DG, such as rebates or a favorable tariff structure, to take credit for that DG. Second, EPA should offer guidance on how DG can meet the requirements of an emission standard by being quantifiable, verifiable, non-duplicative, and enforceable.

i. Policy Mechanisms to Support Distributed Generation

Distributed generation comes in two basic forms: generation at a customer's home or business, and stand-alone systems. Customer-sited DG is intended primarily to meet the customer's own load and exports to the local distribution system only when generation exceeds load. Many utilities compensate for this export through net metering, which credits all exports at the retail electric rate, nets those credits against the customer's purchases from the grid, and then either bills the customer for any shortfall or rolls the surplus over to the following month's bill. The simplicity and fairness of net metering has been a leading source of growth in distributed solar generation. Some utilities offer less favorable terms to DG customers by compensating for exports at less than the retail rate, or not rolling over excess from month to month. These sorts of arrangements should not be characterized as creating incentives for distributed generation. In these circumstances, the customer is installing a distributed generation system at their own cost, without support from the state or utility.

Value-of-solar tariffs are a new compensation mechanism in which 100 percent of the distributed solar generation is metered (rather than only the export), and the rate paid for each kWh generated is based on the sum of avoided utility, environmental and social costs offered

[322] Distributed wind is also interconnected with the utility's system, but not nearly at the scale of distributed solar.
[323] *SPC TSD* at 69, 80.

by the solar generation. In a few instances, feed-in tariffs are used to compensate customer-sited generation, but feed-in tariffs are more common for stand-alone DG systems.

Stand-alone DG is generally compensated through either a feed-in tariff, or under PURPA's mandate that distribution utilities purchase the generation from qualifying facilities.[324] EPA's State Plans Considerations TSD describes the compliance issues with feed-in tariffs thoroughly, but fails to recognize some of the complexities presented in the fast-growing area of customer-sited solar that is typically net metered.

We recommend that a utility should not receive credit simply for having distributed generation interconnected with its system—it is essential that the utility have offered some kind of incentive. Extensive experience in states has shown that distributed solar is most likely to be installed where net metering is available, and that special fees on net metering customers or failure to roll credits over from month to month stifle DG development. Offering customers a rebate of a percentage of the installation cost of their system, or performance-based incentives is also helpful to DG growth.[325] Feed-in or value of solar tariffs that are less than the retail rate, or that fail to offer sufficient long-term price guarantees do not incentivize DG. Therefore, DG installed under these circumstances should not be credited to the utility. Another new model being proposed in some states, including Arizona, is for the utility to directly own and install distributed generation at its customers' locations. Since the utility owns the system, it would clearly be able to use that system's output for compliance purposes. Finally, the high upfront capital costs associated with distributed generation lend themselves to investment by third parties, including compliance entities. Especially for EGUs that are not part of a vertically integrated utility, we believe that offering rebates for a substantial portion of the installation cost of a rooftop solar system should be an approved compliance measure.

ii. Compliance Demonstration for Customer-Sited Distributed Generation

For distributed generation measures to qualify as an enforceable emission standard, the emission reductions must be quantifiable, non-duplicative, permanent, verifiable, and enforceable. We offer the following comments regarding how distributed generation can meet these criteria.

[324] PURPA is a federal policy implemented by the state utility commissions, which determine the fair rate for energy and capacity that should be paid to renewable qualifying facilities. EPA should clarify whether renewable energy purchased by a utility pursuant to PURPA qualifies as a compliance measure, since it is pursuant to a preexisting federal mandate.

[325] *See* Bird et al., NREL, *Distributed Solar Incentive Programs: Recent Experience and Best Practices for Design and Implementation*, NREL/TP-6A20-56308 (Dec. 2012), *available at* http://www.nrel.gov/docs/fy13osti/56308.pdf.

A. Quantifiable and Verifiable

EPA defines quantifiable to mean "capable of reliable measurement, using technically sound methods, in a manner that can be replicated." In the State Plans Considerations TSD, EPA notes that DG systems are not always metered for total generation, only exported energy.[326] Unlike utility scale generation, or larger distributed generation systems installed based on PURPA or feed-in tariffs, distributed generation units do not typically have revenue-grade metering but rely on inverter readings of generation instead.[327] In many cases it would be prohibitively expensive to retrofit installed DG systems with revenue-grade metering, or require those meters on all future installed systems, given their small size. We urge EPA to include in the final rule specific requirements for reliably quantifying and verifying distributed generation without a requirement for revenue-grade metering

Not all REC tracking systems permit distributed generation systems that lack revenue-grade metering to register as REC generators. If a DG system meets the requirements to register its RECs, and those requirements meet EPA's standards for data quality, then we believe it is appropriate for the utility to use those RECs towards compliance (assuming the utility has acquired the RECs, see below). The suggestions that we make below regarding alternative measurement and verification for DG systems should be used only where revenue grade metering is absent or RECs cannot otherwise be registered.

Capacity-based estimates can provide a solid basis for quantifying DG system output. These estimates should take into account the size, orientation and vintage of the system, as newer systems are slightly more efficient. All customers wishing to install solar DG must sign an interconnection agreement with the utility that involves payment of a fee, inspection of the customer's system, and an evaluation of the safety of interconnecting with the distribution grid. Data from these interconnection agreements could readily be used by the utility to quantify the installed capacity on its system, and the utility could gather any additional information needed regarding the orientation and shading of the system during the on-site inspection that occurs as part of interconnection. An increasing number of utilities are using tools such as Clean Power Research's PowerClerk to manage their distributed generation applications.[328] Solar Anywhere and similar solar irradiance data sets, combined with engineering information regarding size and orientation of panels provide very accurate forecasts of likely generation. These forecasts have been validated by metering of in-place systems, and are relied upon by private investors that fund rooftop solar through third-party leases to provide high-quality information about the

[326] *SPC TSD* at 80.
[327] For DG supported by feed-in tariffs or standard contract QFs, the utility should already have revenue-quality metering regarding generation, and be reporting power purchased through these vehicles to the PUC. EPA generally indicates that this level of record-keeping, as supervised by the PUC, will suffice.
[328] *See* Clean Power Research, *PowerClerk*, http://www.cleanpower.com/products/powerclerk/ (last visited Nov. 16, 2014).

likely revenues from a system.[329] Utilities regularly rely on capacity-based estimates of generation for load forecasting purposes.

If EPA allows the use of capacity-based estimates, it must require rigorous verification of those estimates with spot metering at a statistically-valid sampling of sites. EPA should also state whether the utility or other entity seeking credit for DG can validate capacity-based estimates using sophisticated software resources that report to owners and utility whether they are getting the expected generation from their systems or whether the system is experiencing a malfunction or needs maintenance. EPA should offer guidance on these and other methods for verifying capacity-based estimates of distributed generation, but must impose some kind of additional validation measures.

When the generation of a distributed system is considered, the utility or other entity claiming credit should account for the fact that DG avoids line losses due to its proximity to load. This should be factored in when determining the effective generation levels of these systems.

B. Non-Duplicative and Permanent

To ensure that DG is not being double-counted, EPA should address two issues in the final rule. First, some load-serving utilities treat distributed generation as a load-side resource—that is, adjusting load forecasts to reflect anticipated growth in customer-sited generation.[330] If the utility does so, then the full capacity-based generation of the DG should not also be counted by the utility for Building Block 3 purposes.

Second, if the load-serving utility does not receive the RECs for exported generation, there is a risk of double-counting as these RECs could be registered by the rooftop system owner and sold elsewhere.[331] Load-serving utilities do not always receive RECs from the customer-sited generation. In some states, RECs are transferred to the utility without any additional payment, whereas in other states, the utility receives the RECs only if it has offered an incentive to the customer at the time of solar installation. In other states (or for certain utilities within states), the customer retains the RECs.[332] Thus, in states where RECs are not

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[329] *See* Solar Anywhere, *Data*, https://www.solaranywhere.com/Public/SelectData.aspx (last visited Nov. 19, 2014).

[330] *See* Sterling et al., NREL, *Treatment of Solar Generation in Electric Utility Resource Planning*, NREL/TP-6A20-60047 (Oct. 2013), *available at* http://www.nrel.gov/docs/fy14osti/60047.pdf. As part of this study, a survey of utility IRP practices showed that "most utilities today treat DG as a net load impact rather than as a [supply] resource. *Id.* at 25.

[331] Not all customer-sited DG systems will be able to register with REC trading systems, depending on the eligibility requirements of the particular system.

[332] IREC's Freeing the Grid project produces an annual report, Best Practices in State Net Metering Policies and Interconnection Procedures, describing each state's policy based on the best information available at that time. The most recent report was published in November 2014; *see* Auck, et al., Interstate Renewable Energy Council/Vote Solar, *Freeing the Grid 2014: Best Practices in State Net*

currently transferred to the utility, the utility will need to amend its rules (or seek a change in state law) to take possession of those RECs. This will likely require paying some extra value for the RECs, which are currently a separate source of revenue for DG system owners.

Finally, in order for DG measures to meet the permanence requirements, utilities should be required to keep accurate records regarding installation dates of DG systems and their anticipated service life. EPA must require regular, comprehensive auditing of in-place systems to ensure that damaged or disconnected systems are no longer counted towards the utility's compliance.

In conclusion, we believe that distributed generation will be an important compliance tool for the Clean Power Plan due to its rapidly expanding adoption, assuming that EPA has included it in setting the targets. However, EPA must offer further guidance about the policy issues unique to distributed generation, including those topics highlighted above. Without detailed guidance and some assurance about what kinds of distributed generation policy tools will count for compliance, states may choose less environmentally beneficial tools rather than DG to achieve their target emission rates.

D. Building Block 4

1. Building Block 4 is Legally and Technically Justified as an Element of BSER.

Like renewable energy, energy efficiency is a cost-effective system of emission reduction that is adequately demonstrated, as evidenced by the experience of states and utilities that have implemented these policies and programs for years. EE also imposes minimal environmental costs and reduces overall energy requirements. As such, it is an appropriate element of BSER.

a. Low Costs of Energy Efficiency

In its proposed rule, EPA concluded that the costs of demand-side energy efficiency measures reflected in its best practices scenario and the associated CO_2 reductions are reasonable and will result in reductions in electricity bills by the end of the compliance period. 79 Fed. Reg. at 34,872-75. These estimates, however, are very conservative, particularly since energy efficiency is well recognized as a cost-effective (and in most cases the least-cost) method to reduce greenhouse gases.[333] The costs associated with the best practices scenario were estimated based on the average energy efficiency program costs per unit of first-year energy savings, the ratio of program to participant costs, and the life times of the energy efficiency measures. These factors are reflected in EPA's estimated levelized cost per MWh of saved energy ("LCOSE") of \$85/MWh to \$90/MWh (\$2011) over the compliance period. *Id.* at

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Metering Policies and Interconnection Procedures (Nov. 2014), *available at* http://www.slideshare.net/VoteSolar/ftg-2014-finalreport.

[333] Konschnik, *supra* n. 85 at 2.

34,874. As the agency itself notes, this estimate is very conservative, and leads to higher costs when compared with most utility and state analyses. *Id.*

The American Council for an Energy Efficient Economy ("ACEEE") reviewed utility sector energy efficiency program costs between 2009 and 2012 for seven states, and found that energy efficiency programs, together with participant costs, amount to an average cost of $0.054/kWh or $54/MWh ($2011).[334] While these costs correspond to the average of the years 2009-2012 vis-à-vis EPA's levelized forecast for 2020-2030, EPA's estimates are too high when compared to energy efficiency cost trends assessed by ACEEE in recent years. The average utility costs of saved energy in ("CSE") in ACEEE's recent reviews are the following:

Table 8- Average Utility Costs of Saved Energy, 2004-2014[335]

ACEEE's Review	CSE Range	Median/Average Cost
M. Kushler, et. al. (2004)[336]	$0.023-$0.044/kWh	$0.03/kWh
Friedrich et. al. (2009)[337]	$0.016-$0.033/kWh	$0.025/kWh
Molina (2014)[338]	$0.015-$0.048/kWh	$0.28/kWh

ACEEE's most recent values are only slightly higher than the average CSE 2009 review value ($0.025/kWh), and slightly lower than the average CSE 2004 value ($0.030/kWh). Likewise, in analyzing the benefits of energy efficiency as a compliance mechanism, ICF has estimated an incremental value of additional energy efficiency of $0.012/kWh in 2030 when compared to a scenario where 2012 energy efficiency savings and spending remain constant ($2013).[339] These trends and estimates do not support EPA's high cost estimates of energy efficiency during the proposed compliance period.

EPA has also assumed a cost escalation factor representing the possibility of increased costs associated with higher incremental efficiency savings. 79 Fed. Reg. at 34,874. ACEEE's latest review actually compares CSE values to relative electricity savings thresholds (i.e. savings as a percentage of applicable retail electricity sales), finding only a weak correlation between the two values, which "cast[s] doubt on the hypothesis that programs with higher electricity savings levels are associated with higher CSE values."[340] Some experts actually suggest that the

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334 Molina, Maggie, ACEEE, *The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs*, Report No. U1402 (March 2014), attached as **Ex. 32**, at 23.
335 *See generally id.*
336 Kushler et. al., ACEEE, *Five Years In: An Examination of the First Half-Decade of Public Benefits Energy Efficiency Policies*, Report. No. U041 (Apr. 2004), attached as **Ex. 33**, at 30.
337 Friedrich et. al., ACEEE, *Saving Energy Cost-Effectively: A National Review*, ACEEE, Report No. U092 (Sept. 2009), attached as **Ex. 34**, at 5-6.
338 Molina, *supra* n. 334, at 18-19.
339 Pickles et al., ICF International, *EPA's 111(d) Clean Power Plan Could Increase Energy Efficiency Impacts, Net Benefits, and Total Value* (Oct. 28, 2014), attached as **Ex. 35**, at 5.
340 Molina, *supra* n. 334 , at 29-30.

increasing penetration of information technology may result in energy efficiency resources becoming progressively cheaper.[341]

b. Environmental Impacts and Benefits of Energy Efficiency

Energy efficiency measures entail several "non-energy" benefits in addition to the anticipated energy savings, which "range from reduced maintenance costs and lower waste of both water and chemicals to increased product yield and greater product quality."[342] These benefits are sufficiently large so that they can diminish the payback period of the energy efficiency measures.[343] In addition, savings through energy efficiency "can mitigate health and environmental effects associated with the extraction, processing, and transportation of fossil fuels."[344] EE resources are therefore not only among the least-cost options for reducing CO_2 emissions, they impose no independent non-air environmental impacts and actually reduce those impacts from other sources.

c. Energy Requirements of Energy Efficiency

The most widely recognized energy-related benefit of demand-side energy efficiency is energy savings from decreased electricity demand. By reducing demand, energy efficiency contributes to grid reliability, primarily in terms of supply adequacy. Energy efficiency measures implemented within a particular service area or region can reduce the base load, the amount of energy required to be supplied, and the peak power demand.[345]

Efficiency can also contribute to reliability at the level of local transmission and distribution ("T&D") networks by decreasing the likelihood of failures at those points in the system. The benefits of using energy efficiency to defer investments in T&D associated to address load growth can be substantial. Deferrals of T&D investments can occur as a result of efficiency programs that were not undertaken primarily to defer T&D upgrades. For example, in the past Consolidated Edison ("Con Ed") reduced its projected T&D capital expenditures after adjusting 10-year load forecasts for each of its distribution networks to reflect the expected impacts of system-wide efficiency programs.[346] But, in some instances, energy efficiency programs have been geographically targeted for the specific purpose of deferring such investments. For example, between 2003 and 2010, Con Ed employed geographically targeted

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[341] Laitner et al., ACEEE, *The Long-Term Energy Efficiency Potential: What the Evidence Suggests*, ACEEE Report No. E121 (Jan. 2012), attached as **Ex. 36**, at 11.
[342] *Id.* at 10.
[343] *Id.*, at 10-11.
[344] Konschnik, *supra* n. 85 at 7.
[345] Raynolds & Cowart, Alliance to Save Energy/Regulatory Assistance Project, *The Contribution of Energy Efficiency to the Reliability of the U.S. Electric System* (May 26, 2004), attached as **Ex. 37**.
[346] Neme & Sedano, Energy Futures Group/Regulatory Assistance Project, *US Experience with Efficiency as a Transmission and Distribution System Resource* (Feb. 2012), attached as **Ex. 38**, at i.

efficiency programs to defer upgrades in more than one third of its distribution networks, with the resulting savings providing more than $300 million in net benefits to ratepayers.[347]

d. Energy Efficiency is "Adequately Demonstrated."

Demand side energy efficiency programs have a long record of achieving energy savings. Customer-funded energy efficiency programs provided by electric utilities have existed since the 1970s, and utility sector energy efficiency has evolved to become a top priority utility system resource."[348] Several states have established policies that mandate energy efficiency as first resource in the loading order of electric utility resources, as well as requirements that states should capture "all cost-effective energy efficiency."[349] Twenty-six states have adopted energy efficiency resource standards ("EERS") that establish specific energy savings targets for utilities or independent statewide program administrators, while several others have established short-term energy efficiency goals.[350]

Since the early 2000s, energy efficiency programs have grown at an accelerated rate. In 2006, total spending was $1.6 billion; by 2010, total budgets for electric customer energy efficiency programs grew to $4.6 billion; and in 2013, total budgets for these programs reached $6.3 billion.[351] These expenditures are yielding significant energy savings. In 2009, the national total annual savings from these programs were 13,147 TWh or almost 0.4 percent of total energy sales, with five states saving 1 percent or more during that year.[352] Funding for customer energy efficiency programs is expected to continue rising, particularly in those states that have been minor players in this industry.[353] A large portion of these projected increases in spending are expected to come from the Southeast, which historically has had relatively low levels of funding for energy efficiency.[354]

Energy efficiency is becoming increasingly important because of concerns with fuel price volatility, increased cost of construction of new power plants and doubts about the ability to finance and secure cost-recovery of these projects; shrinking reserve margins leading to reliability questions; and more stringent environmental regulations, including regulations to reduce carbon emissions to address climate change. Energy efficiency is now also being used as a competitive resource. For example, in New England, energy efficiency can compete in the

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[347] *Id*. at ii-iii.

[348] York et al., ACEEE, *Three Decades and Counting: A Historical Review and Current Assessment of Electric Utility Energy Efficiency Activity in the States*, Report No. U123 (June 2012), attached as **Ex. 39**, at 26.

[349] *Id*.

[350] Gilleo et al., ACEEE, *The 2014 State Energy Efficiency Scorecard*, Report No. U1408 (Oct. 2014), *web-based version available at* http://www.aceee.org/state-policy/scorecard, at 21. For details on these programs in different states, *see* Bingaman, *supra* n. 220, at 11.

[351] Gilleo*, supra* n. 350*,* at v.

[352] York, *supra* n. 348, at 2.

[353] *Id*. at 28.

[354] Gilleo, *supra* n. 350, at 19.

forward capacity market, and FERC is analyzing how to incorporate energy efficiency in wholesale markets. Energy efficiency is also being used specifically as a greenhouse gas reduction strategy. The Regional Greenhouse Gas Initiative ("RGGI") includes explicit provisions for credits for energy efficiency that generate funding for energy efficiency savings.[355] This track record provides valuable insights on the future potential of energy efficiency as a resource and as a carbon reduction option.

In its proposal, EPA estimates that, for the best practices scenario, states can achieve incremental energy savings of 1.5 percent of annual retail sales over a period of years starting in 2017 and, at the latest, by 2025. 79 Fed. Reg. at 34,872. As discussed below, while a 1.5 percent rate is a reasonable estimate that is adequately demonstrated, EPA should consider whether states can achieve a higher rate through utility efficiency programs. In its most recent "Scorecard," ACEEE found that six states achieved or exceeded this level of savings in 2013, as shown in Table 9 below:

Table 9- 2013 Net Incremental Electricity Savings by State[356]

State	2013 Incremental Net Savings (MWh)	% of Retail Sales (2013)
Rhode Island	161,831	2.09%
Massachusetts	1,116,442	2.05%
Vermont	99,074	1.78%
Arizona	1,317,329	1.74%
Hawaii	159,056	1.67%
Michigan	1,284,863	1.51%

Of these states, EPA assumes that Rhode Island will achieve a 1.5 percent savings rate until 2021, and Hawaii will do so until 2025. Massachusetts, Vermont, Arizona, and Michigan are assumed to reach this rate in 2020.[357] Additional states currently have annual savings targets for the period 2014-2020 that are equal or higher than EPA's proposed estimate:

Table 10- State Scores for Energy Efficiency Resource Standards[358]

State	Approx. Annual Savings Target (2014-2020)	Approx. % of Retail Sales Covered by EERS
Massachusetts	2.6%	86%
Arizona	2.4%	56%
Rhode Island	2.3%	99%
Vermont	2.0%	100%
Maryland	1.6%	100%

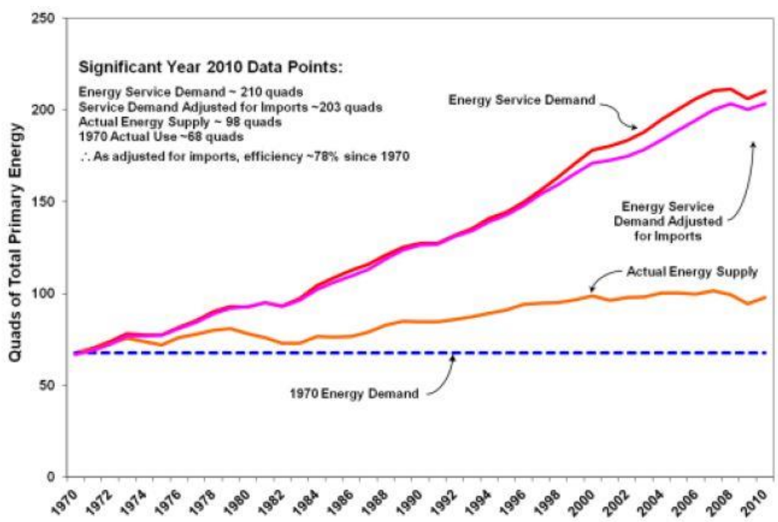
[355] *Id*. at 26-27.
[356] *Id.* at 33.
[357] *Abatement Measures TSD* at Appendix 5-4.
[358] Gilleo, *supra* n. 350, at 38-39.

Maine	1.6%	100%
Minnesota	1.5%	86%
Colorado	1.5%	57%

Of the additional states in this list, only for Maine and Minnesota does EPA assume that these states will reach the target during their EERS period (2017 and 2020, respectively), while for Maryland and Colorado EPA assumes that these states will not hit the 1.5 percent annual savings rate until 2021.[359] Therefore, while we agree with EPA that a 1.5 percent incremental annual savings rate is achievable, we suggest that the agency consider whether states can achieve a higher target through utility efficiency programs.

Figure 1 illustrates the level of new energy supply that would have been needed in the absence of productivity gains due to energy efficiency (from 1970 through 2010).[360] The chart shows that in 1970, Americans consumed an estimated 68 quadrillion BTUs (quads) for all uses of energy. Had the country continued to rely on 1970 market structure and technologies to maintain economic growth, in 2010 we would have consumed an estimated 210 quads of energy resources. In fact, the actual level of consumption estimated for 2010 was just short of 98 quads.[361] Part of these reductions in consumption is due to the implementation of energy efficiency measures, and the opportunities further demand reductions through efficiency remain abundant.

Fig. 26- U.S. Energy Demand, Energy Efficiency Gains, and Energy Supplies[362]



[359] *Id.*
[360] "Energy efficiency" here refers to both a change in market structures as we move away from energy-intensive industries to services industries, as well as actual energy efficiency measures: more efficient lightning and consumer products, greater fuel economy in vehicles, and more efficient power plants and industrial processes. *Id.*, at 3, fn. 4.
[361] *Id.* at 3-4.
[362] *Id.* at 5.

2. EPA's Building Block 4 Reflects a Level of Energy Efficiency Savings that Can Be Cost-Effectively Achieved in All States

As described previously, EPA's decision to include demand-side energy efficiency as part of the best system of emission reduction is legally sound and reflects the broad treatment of energy efficiency as an electric system resource on par with generation. EPA's methodology for developing the energy efficiency targets as part of Building Block 4 is also generally sound, though several improvements should be made.

a. EPA's Best Practice Level of Performance is Achievable and Sustainable in All States.

In brief, EPA looked at the demonstrated level of energy efficiency achieved by PUC-supervised EE programs across the states, identified the top-performing states, and determined the best practice level of performance. EPA then determined what it believed to be a reasonable rate of incremental growth in EE savings, and applied that rate of growth to each state's beginning level of performance in 2017 until the state reaches the best practice level of performance.

EPA set the best practice level of performance at 1.5 percent--meaning that a state's EE programs reduce its retail electric sales of electricity by 1.5 percent annually. This is the peak rate of annual load reduction that a state is expected to achieve, even if that state has EE program targets higher than 1.5 percent. EPA based this level on the observed performance of EE programs in three states--Arizona, Maine and Vermont—and the fact that nine additional states are expected to reach this level of savings by 2020.[363]

In determining what level of energy efficiency should be deemed the "best practice," EPA should keep in mind that the current utility revenue structure in most states provides a significant disincentive to implementing strong energy efficiency programs. The primary way that a load-serving utility can elevate profits is to increase electricity sales above forecasts made during the utility's last rate case.[364] Thus, the utility has a deeply ingrained motivation not to reduce electricity sales, which is commonly referred to as the "throughput incentive." Although some states have instituted decoupling to some extent—a policy that breaks the link between electricity sales and utility revenue recovery—for the majority of utilities in the country, it is counter to the utility's business logic to implement energy efficiency programs. States have developed ways to overcome the utilities' reticence, such as offering incentives for achievement of EE targets, or imposing penalties for failure to meet them. But in general, the picture of EE program achievement in recent years reflects this significant barrier, and should

[363] *Abatement Measures TSD* at 5-33, Tables 5-8 & 5-9.

[364] *See* Regulatory Assistance Project, *Revenue Regulation and Decoupling: A Guide to Theory and Application* (June 2011), *available at* http://www.raponline.org/docs/RAP_RevenueRegulationandDecoupling_2011_04.pdf.

be viewed as a conservative estimate of what is achievable with a proper incentive structure for utilities.

A number of other factors inhibiting energy efficiency are reflected in the data EPA used to set the EE targets. EE achievement has also been hampered by the lack of long-term political support in many states. In some states, like Arkansas, targets are set for only three-year periods, leaving utilities unable to optimize their planning for longer-term programs. Other states impose cost caps that limit the amount a utility may spend on utility programs, even if limiting spending means the utility will not achieve its targets.[365] Still others, such as Texas, have designed their programs to focus on peak demand reduction, rather than overall energy savings. While peak demand reduction programs are highly valuable to ratepayers and require sophisticated implementation and EM&V, they would not necessarily show up in the EIA-861 data as significant load reductions.

The 1.5 percent best practice level of performance is sustainable. EPA appropriately notes the long history of strong EE progress in the Pacific Northwest.[366] A recent review of energy efficiency potential in Rhode Island, found that annual energy efficiency targets as high as 2.5 percent remained feasible over the next ten-year period.[367] There are many markets that most energy efficiency programs have not even begun to tap, including multi-family homes, rental property, and mobile homes. As utilities develop programs serving these markets, new opportunities for savings will arise.[368]

While we believe that 1.5 percent is attainable for all states, we believe that it is unlawful for EPA to cap a state's performance at 1.5 percent if existing state law requires a higher target. For example, Arizona utilities are expected to achieve 2.5 percent savings annually beginning in 2016.[369] Several Colorado utilities will achieve 1.66 percent savings by 2019. Illinois utilities are required to achieve 2 percent savings in 2015 and thereafter. Maine has an approximate target of 1.6 percent for 2020.[370] Massachusetts has a target of 2.6 percent by 2015. Rhode Island mandated that its utilities achieve 2.5 percent savings by 2014. Just as it was contrary to the CAA for EPA to set state renewable energy targets below their established RPS targets, EPA cannot set state EE targets below established standards.[371] In addition, when

[365] *See* Downs & Cui, ACEEE, *Energy Efficiency Resource Standards: A New Progress Report on State Experience* (Apr. 2014), Report No. U1403, at 9.
[366] *Abatement Measures TSD* at 5-38.
[367] Rhode Island Public Utilities Commission, *Proposed Energy Efficiency Savings Targets for National Grid's energy efficiency procurement for the period 2015 - 2017 consistent with Least Cost Procurement,* Docket No. 4443 (filed Sept. 26, 2013), *available at* http://www.ripuc.org/eventsactions/docket/4443page.html.
[368] Downs & Cui, *supra* n. 365 at 23.
[369] All targets listed in this paragraph are from Downs & Cui, *supra*, at Appendix A.
[370] Maine's EE program administrator—Efficiency Maine—is required to pursue all cost-effective energy efficiency, rather than a specific numeric target.
[371] We recognize that the state targets cited above do not apply to 100 percent of electricity sales in state, and therefore may require some adjustment when applied as a floor.

EPA sets the 2017 start level of performance for each state, those levels cannot be below the mandates already established in that state. EPA sets the 2017 levels equal to the 2012 level of savings, which does not reflect the progress on EE expected in many states.

EPA's alternative best practices level of performance—1 percent—is far below the cost-effective EE potential. That this alternative target is excessively conservative is demonstrated by the number of states already achieving higher levels of performance and the number of states with plans to exceed that level of performance by 2020. In addition, a meta-analysis of 45 studies of efficiency published in August 2014 (after publication of the proposed rule) found that "average annual maximum achievable savings range from 0.3 percent to 2.9 percent with a median of 1.3 percent."[372] Importantly, this study also found that assessments of potential savings did not vary by geography.[373] When considering the value of energy efficiency potential studies for target setting, EPA should keep in mind that estimates of achievable EE are heavily dependent on energy prices and the utility's avoided costs. In other words, the level of energy efficiency that is cost effective is higher in a world where states must reduce the carbon emissions from their utility sector, rather than one where carbon emissions are unconstrained, which is typically the world reflected by existing potential studies.

b. State EE Targets Should Be Based on All Sales in the State, Including Imported Electricity.

In factoring emission reductions from energy efficiency measures into the state targets, EPA tracks whether a state is a net importer or net exporter of electricity. If the state is a net importer, EPA scales down the amount of avoided generation demand resulting from those EE measures in order to "reflect an expectation that a portion of the generation avoided by the demand-side energy efficiency would occur at EGUs in other states." 79 Fed. Reg. at 34,896.[374] For example, EPA's 2030 emission target for Florida assumes the state can use energy efficiency measures to reduce demand by 9.98 percent from 2012 electricity purchases (multiplied by a transmission loss factor of 1.0751), which in Florida amounts to savings of approximately 23.7 million MWh. In-state generation accounted for approximately 90 percent of Florida's 2012 electricity purchases, with the remaining 10 percent imported from other states. Accordingly, EPA reduces Florida's expected energy savings of 23.7 million MWh figure by 10 percent, and adds the resulting total—approximately 21.3 million MWh—to the state's denominator.

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[372] Neubauer, ACEEE, *Cracking the TEAPOT: Technical, Economic, and Achievable Energy Efficiency Potential Studies*, Report No. U1407 (Aug. 2014), Executive Summary attached as **Ex. 40**, at *v*.

[373] *Id.*

[374] EPA makes this adjustment to reflect that not all of the state's EE savings will result in emission reductions at in-state units. However, regardless of whether a state is a net importer or a net exporter, its EE programs can affect dispatch of out-of-state EGUs, since reduced load will lead to reduced operation of whichever EGU on the system is marginal at the time the load reduction occurs.

On the other hand, EPA does not "scale up" generation avoided from EE measures in states that are net *exporters* of electricity. For instance, Alabama is a net exporting state: in 2012, its in-state generation exceeded its in-state electricity purchases by approximately 50 percent, indicating that a third of the state's generated electricity was exported to other states. EPA's target assumes that Alabama can implement energy efficiency measures that save 9.5 percent of 2012 generation figures by 2030. This amounts to a demand reduction of roughly 8.8 million MWh, which is added to Alabama's denominator. Notably, EPA does not increase this figure by 50 percent to account for the fact that Alabama exports a third of its generated electricity to other states, even while it decreases the energy savings figure achieved in net importing states as described above.

EPA's asymmetrical approach to imports and exports means that large swatches of electricity that can be avoided by Building Block 4's EE measures are effectively "stranded": the state targets simply do not account for these reductions. In Alabama, this amounts to about 2.4 million MWh that is removed from the state's denominator; nationwide, the total is approximately 41 million MWh. EPA must remedy this situation and set appropriately stringent state targets that account for *all* the electricity generation that can be avoided by the EE opportunities the agency has identified in Building Block 4.

The simplest and fairest "fix" to this problem is to avoid scaling down the obligations of importing states, and to recalibrate those states' targets to account for 100 percent of the demand reduction achieved through EE measures. It is important to remember that the EE targets specified in Building Block 4 merely specify what is achievable in each state—they include no assumptions about how the responsibility for implementing those measures should be distributed across the state's utilities or affected EGUs. It is therefore both feasible and fair to assign responsibility to in-state generators for achieving the level of EE savings specified in Building Block 4.[375] The only other approach that would avoid stranded EE savings would be to require exporting utilities to implement efficiency measures in other states, which would raise both legal and logistical challenges.[376]

Our recommended approach would make EPA's methodologies for renewable energy and energy efficiency consistent. EPA does not adjust the state's renewable energy target to reflect that many of the emission reductions resulting from the state's RE measures will be at out-of-state facilities, and should treat energy efficiency savings the same way. Just as many

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[375] We recognize that in many states, EE programs are implemented by load-serving utilities that do not also own generation. Even in states with vertically integrated utilities, there are some independent power producers (also known as merchant plants) that are not affiliated with load-serving utilities. Where there is not common ownership between the party currently implementing the EE program and the affected EGU, the state will need to either administratively allocate or auction EE savings generated by those programs, or adopt a tradable credit mechanism to enable affected EGUs to acquire the credits needed to achieve their target emission rates.

[376] EPA requests comment on the alternatives approaches of adjusting both importing and exporting states, and making adjustments to neither. 79 Fed. Reg. at 34,879. To be clear, we support the alternative of making no adjustment to the EE targets based on import/export status.

states allow out-of-state RE to be used for RPS compliance, states with energy efficiency programs do not distinguish among where the savings occur. The objective of EE programs is to produce savings for customers by reducing the need to purchase electricity and reducing the load-serving utility's capacity requirement and delaying upgrades to the transmission and distribution system. It does not matter where the electricity would have been purchased from—the ratepayers save in any case. Therefore, EPA should follow the same rationale with EE target setting as it did for RE, and accommodate existing state programs that are indifferent to where resources are acquired or emission reductions are realized.

EPA's approach also relies too heavily on the net importation factor from a single year in setting state targets for 2030. The percentage of energy that a state imports or exports can change significantly from year to year, as units enter and exit the system and new transmission lines are built. As the state of Oregon has pointed out, hydroelectric production is highly variable,[377] which could cause major swings in a state's export-to-import ratio. Basing the state's target on its export-to-import ratio for one year could lead to targets that are either too high or too low. The simplest solution is for EPA to include 100 percent of the EE potential in the target and to allow states to count 100 percent of those savings towards compliance.

In conjunction with this adjustment to the goal-setting methodology, we also recommend that EPA allow states to take credit for 100 percent of their EE savings, rather than discounting the savings for net importing states. Notably, our recommendation to remove the EE scale-down factor for net importing states will impose no additional burdens on any state that in fact meets the EE components of its state goal. For instance, in the case of Florida, while its target will be more stringent under our approach due to the additional 2.4 million MWh in its denominator, the state would count 100 percent of the MWh avoided due to EE when determining compliance with its designated target, rather than 90 percent. Because the scale-down factor would be removed both from the target-setting and compliance-determination calculations, Florida would have no more difficulty complying with a rule that does not include the scale-down factor than one that includes it.

In fact, if an importing state exceeds the level of EE implementation specified in Building Block 4, our accounting method would give that state an added benefit. If Florida were to avoid 30 million MWh through EE measures, our proposed method would allow the state to add all 30 million MWh to its compliance denominator, 6.3 million MWh more than the 23.7 million MWh that Building Block 4 would add to the state's target denominator. Under EPA's scale-down approach, Florida would add 27 million MWh to its compliance denominator (90 percent of 30 million), while its target denominator would include 21.3 million MWh (90 percent of 23.7 million), a difference of 5.7 million MWh. Hence, under our approach, Florida would gain *more* additional credit in its compliance denominator by exceeding its EE targets than it would under EPA's scale-down method.

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[377] Oregon Dep't of Envtl. Quality, *State of Oregon Comments on Clean Power Plan*, Docket No. ID EPA-HQ-OAR-2013-0602-20678 (Oct. 16, 2014), at 5.

The only states that will be required to meet an additional burden under our method are those states that fall short of EPA's target EE goals. In the example above, if Florida were to avoid 20 million MWh through EE measures rather than EPA's assumed 23.7 million MWh, our method will tabulate this as a 3.7 million MWh shortfall that the state must make up for through other emission reduction measures. Under EPA's downscaling method, EPA will only add 21.3 million MWh to the target denominator and will credit Florida with 18 million MWh avoided—a difference of 3.3 million MWh. Hence, under our proposed system, this state will need to make up a 3.7 million rather than 3.3 million MWh shortfall.

By eliminating the problem of "stranded EE assets," our method has the benefit of encouraging states to implement EE measures that exceed EPA's targets and discouraging them from falling short of those targets. Since EE is, in the aggregate, the most economically efficient way of reducing carbon emissions, our proposal will improve the rule's overall cost-effectiveness. We emphasize that our method does not actually revise EPA's assumptions about each state's capacity to implement EE—rather, it simply ensures that those figures are correctly tabulated in each state's goals and provides the proper incentives for states to meet those goals.

Using a tool developed by MJ Bradley & Associates,[378] we evaluated the impact of our method on state targets. Twenty-four states had final targets made more stringent by this change, as follows:

- For 8 states, final target rates decrease by 1 percent or less (AK, FL, HI, KY, LA, MS, NV, RI)
- For 11 states, final target rates will decrease by between 1.1 and 5 percent (CO, GA, MA, MN, NJ, NY, NC, OH, SD, TN, WI)
- Only 5 states will see their final target rates decrease by more than 5 percent, specifically:
    - Virginia: 6.9 percent
    - Maryland: 9.6 percent
    - Idaho: 23.9 percent
    - Delaware: 7 percent
    - California: 5.1 percent

Clearly, the impact of this adjustment is largest for the state of Idaho, which would need to achieve a final adjusted emission rate of 184 rather than 228. However, as noted above, Idaho would at the same time benefit from being allowed to count 100 percent of its energy efficiency savings towards its state goal.

[378] M.J. Bradley & Associates Clean Power Plan Evaluation Tool (2014 version 2). The tool is available at www.mjbradley.com.

c. **EPA Should Readjust its Goal-Setting Formula to Reduce Dispatch of Fossil Units In Accord with Increased Energy Efficiency**

As discussed above, EPA has requested comment on whether it should adjust its goal-setting formula such that expected fossil-fired generation decreases to the same extent that RE generation and EE savings increase. We reiterate here that we believe EPA should, indeed, make this change, which will ensure greater emission reductions and reflect the true nature of electricity dispatch. For more discussion of this topic, *see* pp. 94-95, *supra*.

3. **Compliance Considerations for Building Block 4**

We strongly support the use of energy efficiency programs as part of states' efforts to achieve compliance with their targets. Energy efficiency is widely recognized as the least-cost electric system resource—rather than imposing new expenses for the state to come into compliance, customers will actually experience lower bills if the state's plan includes a strong energy efficiency component.[379]

EPA has stated that to count towards compliance, each part of the emission standard, including energy efficiency, must be quantifiable, non-duplicative, permanent, verifiable, and enforceable. For energy efficiency, these criteria can be interpreted generally as follows:

- **Quantifiable and verifiable:** Are sufficiently rigorous EM&V procedures in place to enable the reliable measurement of savings in megawatt-hours and to calculate avoided CO_2 emissions if required by EPA?
- **Non-duplicative:** Is another state also using those same avoided megawatts hours or avoided emissions towards their compliance with the Clean Power Plan?
- **Permanent:** Are the savings from an installed measure ongoing during the year in which the state seeks to use them for compliance?
- **Enforceable:** is there an entity with federally enforceable commitments to procuring energy efficiency savings?

EPA's proposed rule, technical support documents, and existing guidance do an excellent job of describing how energy efficiency meets these criteria. We offer comments on a few of the keys issues below. We also urge EPA to reconsider its proposal to only allow states to count energy efficiency savings that occur at in-state affected EGUs.

[379] *See generally* Molina, *supra* n. 334.

a. Evaluation, Measurement, and Verification

Many of these criteria are encompassed in the evaluation, measurement and verification ("EM&V") procedures already used to demonstrate savings from EE programs. The fundamental purpose of EM&V programs is to identify megawatt-hours saved as a result of EE programs. Program evaluators take steps to ensure that the savings realized would not have otherwise occurred, which is critical in order for the savings to be non-duplicative. These existing procedures lend themselves well to the purposes of the Clean Power Plan.

We agree with EPA that further guidance is needed to assist states in designing compliant EE programs, but in addition to such guidance, minimum standards for state EM&V programs are essential to prevent overly permissive approaches from undermining the achievement of the emission reductions in the CPP. Some states, especially those that are already achieving high levels of annual energy savings, have had several years to develop and test EM&V procedures for a wide array of EE measure types. However, for states that lag in developing this critical system resource, minimum standards and additional guidance will be needed on what types of energy efficiency programs can count towards compliance, and what will constitute adequate EM&V to demonstrate savings from those programs. EPA's Roadmap for the Inclusion of Renewable Energy and Energy Efficiency in State and Tribal Implementation plans is an excellent start on such guidance. EPA and the states can also look to the many excellent collaborative efforts to develop EM&V standards, including NREL's Uniform Methods Project,[380] the State & Local Energy Efficiency ("SEE") Action Network,[381] Northeast Energy Efficiency Partnership's EM&V forum[382] and the Pacific Northwest's Regional Technical Forum.[383]

EPA proposes a qualitative hierarchy regarding the level of EM&V uncertainty for different types of EE programs.[384] To encourage states with weak or nonexistent energy efficiency programs to make that a key part of their plans from the very beginning of the compliance period, we agree that it would be helpful for EPA to set out a predefined list of programs that have well-developed EM&V protocols backed by significant experience. EPA should not limit the states to these types of EE programs,[385] as that would stifle innovation, but laying out a clear path for states with less experience will be extremely helpful in the early years of compliance.

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[380] *See* NREL, *Uniform Methods Project*, http://www.nrel.gov/extranet/ump/(last visited Nov. 21, 2014).
[381] *See, e.g.*, SEE Action Network, *Energy Efficiency Program Impact Evaluation Guide* (Dec. 2012).
[382] *See* Northeast Energy Efficiency Partnerships, *EM&V Forum*, http://www.neep.org/initiatives/emv-forum (last visited Nov. 30, 2014).
[383] Northwest Power and Conservation Council, *Regional Technical Forum*, http://rtf.nwcouncil.org/ (last visited Nov. 24, 2014).
[384] *SPC TSD* at 48.
[385] *Id.* at 50.

With respect to verification, EPA notes that "adequate monitoring, recordkeeping and reporting requirements [must be] in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with [the standard.]" 79 Fed. Reg. at 34,913. Often the data collected by the independent consultant, contractor, or other entity providing EM&V services to the state commission are not presented with the final report summarizing the achieved savings. These data will need to be made available to the agency and other stakeholders, along with complete descriptions of how the data were treated to arrive at the final savings number, in order to allow independent verification. Alternatively, because these data can be voluminous and difficult for a non-expert to interpret, the agency may want to require EE program administrators to undergo occasional audits of EM&V practices by a well-regarded third party.[386]

A final issue relating to quantifiability is whether existing EM&V procedures allow states to determine the avoided CO_2 emissions associated with those savings. As EPA notes in the State Plans TSD, some EE program administrators report only annual energy savings, while others estimate seasonal or hourly savings based on the nature of installed measure. If hourly savings are available or can be readily estimated, this would enable more precise estimates of avoided CO_2. However, as explained in the Renewable Energy Compliance section, we believe that calculating avoided megawatt-hours is sufficiently rigorous to credit both RE and EE in state plans. If EPA determines that states must calculate the avoided CO_2 associated with each megawatt-hour saved, the agency should identify which methodologies are most appropriate for this purpose and how hourly savings data can be estimated if not generated through the state's EM&V plan. As discussed further below, states may need to identify specifically which affected EGUs dispatched less as a result of the savings from their EE programs. EPA must offer detailed guidance on how this can be done with a reasonable degree of certainty.

b. Non-Duplicative

EPA explains that an emission standard is non-duplicative if it is not incorporated into another state's compliance plan. In part to avoid duplication, EPA has proposed that states should receive credit for energy efficiency programs only to the extent that they cause reductions at in-state affected EGUs. *Id.* at 34,922. As EPA explains elsewhere, states may take into account "only those CO_2 emission reductions occurring in the state that result from demand-side energy efficiency programs and measures implemented by the state."[387] We discuss earlier (*see* pp. 124-27, *supra*) why EPA should include 100 percent of each state's energy efficiency potential in BSER. Here, we discuss why EPA should allow states to use all of their achieved EE savings to demonstrate plan performance and how to avoid double-counting in doing so.

[386] We believe that the energy efficiency registry proposed by the Climate Registry, discussed below, would be very helpful in establishing uniform standards and promoting transparency.
[387] *SPC TSD* at 87.

EPA's proposal to count only EE savings resulting in reduced emissions at in-state units would require both ex ante and ex post determinations of whether EE programs resulted in reduced dispatch of in-state EGUs. Alternatively, EPA suggests that net importing states could discount their EE savings by their net import factor (i.e., if the state imports 30 percent of its energy, it could only count 70 percent of its EE savings for compliance).[388]

We believe that allowing net importing states to count only a percentage of their EE savings will be a major disincentive to states employing EE as part of their plans. EPA seems to believe that because EE is so cost-effective, states will adopt it even if allowed to count only a fraction of their savings towards their Clean Power Plan goals.[389] We agree that states should adopt aggressive energy efficiency savings targets to save their ratepayers money, regardless of whether those savings will contribute to the state's plans. In reality, however state decisionmakers on energy issues will focus on complying with the Clean Power Plan after the rule is finalized, and may set aside or ignore any initiative not substantially contributing to the state's plan. Moreover, states will be seeking to minimize the costs of complying with the Clean Power Plan, and this discounting of EE savings may influence the state to consider other options. Furthermore, EPA's proposed approach would create "lost avoided MWhs," which were caused by one state's programs, but were realized in another state. In such a case, neither state could take credit for those emission reductions, effectively increasing the cumulative cost and administrative burden of CPP compliance across the country.

EPA's primary position—that states can take credit for EE savings only if they result in emission reductions at in-state EGUs—would create uncertainty for states. A state may project that its EE programs will result in in-state emission reductions, but find in conducting its ex post plan performance analysis that a percentage of the reductions occurred out of state, and not be able to take credit for those reductions. Such a framework will make it unnecessarily difficult for states and discourage them from using EE as a compliance measure. The proxy approach where the state would use a net importation factor might give states somewhat more certainty, but has its own flaws. If a state reduced its annual EE savings by their net importation factor for the current year, states could be faced with being able to count less of their EE savings than EPA accounted for in the target, if the state is importing more power than it was in 2010.

We advocate that EPA allow states to take credit for 100 percent of the savings resulting from their EE programs. Doing so will enable states to maximize the impact of the most cost-effective resource available for reducing carbon emissions. Unlike with renewable energy, where there is a risk that a competing claim may be staked by the state where the RE resource is located, or by the purchaser of "null power," when all states are rate-based there is no reason that another state would lay claim to those reductions, since they would only be

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[388] *Id.* at 92.

[389] *See* 79 Fed. Reg. at 34,876, n.188 ("Given the extremely low cost of CO_2 emission reductions achievable through demand-side energy efficiency programs, implementation of such programs is likely to reduce CO_2 emissions at reasonable cost even for a state whose own affected EGUs achieve only part of the CO_2 emission reduction benefit from the state's demand-side energy efficiency efforts.").

identified by the entity implementing the EE program. Even where a fossil unit is displaced in a state other than the state taking credit for the EE, that will not result in double counting so long as EPA adopts the annual true-up procedure that we recommend for states with mass-based limits, as discussed on p. 108, *supra*. Because the mass-limited unit will have less generation factored into its rate-to-mass conversion, its overall mass target will be lower, neutralizing the benefit it received by having its emissions reduced due to an out-of-state EE program. No double-counting occurs due to displacement of affected EGUs in rate-based states for the reason we describe in the Renewable Energy Compliance section, supra.

c. Permanent

EPA has stated that "An emission standard is permanent if the standard must be met for each applicable compliance year or period, or replaced by another emission standard in a plan revision, or the state demonstrates in a plan revision that the emission standard is no longer necessary for the state to meet its required emission performance level for affected EGUs."[390] In EPA's 2012 Roadmap for Incorporating EE/RE Policies and Programs into State and Tribal Implementation Plans, the agency says that permanent EE savings are those that continue through the attainment year or in the case of 111(d), the compliance period.

In the energy efficiency world, this is captured by the concepts of "measure life" and "persistence," which includes both the retention of an EE measure and its performance degradation.[391] All EE measures have a limited life based on the lifetime of the underlying technology. In very rare cases, the life of an installed measure may be cut short, such as where a customer uninstalls the measure, or its savings potential degrades due to improper maintenance. For an EE measure to be permanent, it must be in place and generating savings during the compliance year. Therefore, states must ensure that EM&V protocols for ratepayer-funded energy efficiency programs address and report on persistence, which impacts the cumulative savings of the program. EPA guidance should address appropriate EM&V techniques for assessing the persistence of energy savings.

d. Enforceability

Enforceability is a key question for energy efficiency components of a state plan. While some energy efficiency programs are implemented by vertically integrated utilities that also own and/or operate affected EGUs, others are implemented by distribution-only utilities, by third-party administrators, or by state agencies. States have landed on different strategies for implementing their EERS, resulting in a wide variety of entities having obligations under state law. [392] However, the common feature of all of these programs is that they are funded by

[390] 79 Fed. Reg. at 34,913.
[391] NREL, *The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures* (Jan. 2012 – March 2013), attached as **Ex. 41**, at 13-3.
[392] *See* Sedano, R., Regulatory Assistance Project, *Who Should Deliver Ratepayer Funded Energy Efficiency?* (Nov. 2011), attached as **Ex. 42**.

ratepayers, and therefore supervised by the state public utility commission or other governing body (in the case of municipal utilities and electric cooperatives implementing their own EE programs).

As noted earlier, we believe that the operators of the affected EGUs in a state must be collectively responsible for fully achieving the state goal and that the measures to ensure compliance must be federally enforceable against those EGUs. In addition, entities implementing the EE programs can but need not be subject to federal enforceability under the Clean Power Plan, unless that entity also happens to own or operate an affected EGU (i.e., a vertically integrated utility). To the extent that the compliance entities use energy efficiency avoided megawatt-hours in order to achieve their emission target, they can acquire those EE credits from the EE program administrator, under guidelines established by the state and approved by EPA. Whether the state chooses to allocate non-tradeable credits, or set up a tradeable crediting system is its choice based on its existing state laws and considerations.

The details of the EE program must be specified in the state's plan so that EPA can ensure that adequate EE savings credits will be available. Most critically, the EM&V requirements must be described in adequate detail for EPA and other stakeholders to assess whether they are sufficiently rigorous to establish savings attributable to the program. To ensure the availability of efficiency credits, state EE standards must contain penalties for non-compliance and self-correction mechanisms. Some ratepayer-funded energy efficiency programs allow the implementing utility to make up for shortfalls in one year with over-performance in the next. Allowing EE program administrators too much flexibility within a plan period could lead to inadequate EE credits being available in a given year; states must consider how these plan periods align with the Clean Power Plan's two-year check-in schedule.

The allocation of energy efficiency credits to affected EGUs will require more active state involvement than the distribution of renewable energy credits, at least in the early years. Currently, there is no platform for verification and trading of energy efficiency credits, equivalent to the REC trading systems for renewable energy. EPA must establish standards to ensure that EE savings are demonstrated through EM&V meeting the best standards and are not claimed by multiple parties.

A REC equivalent for energy efficiency has been discussed over the years, but has never taken hold in the same way as RECs. Some REC tracking systems, including NEPOOL-GIS, NAR, and NC-RETS, track energy efficiency savings, but the other systems have not incorporated this feature. In the late 2000s there was substantial interest in developing a tradeable market for EE credits.[393] The state of Connecticut had a limited intrastate EE trading market for several years,

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[393] *See, e.g.*, Friedman & Bird, *Energy Savings Certificate Markets: Opportunities and Implementation Barriers* (July 2009), attached as **Ex. 43**; Hamrin et al., Center for Resource Solutions, *The Potential for Energy Savings Certificates (ESC) as a Major Tool in Greenhouse Gas Reduction Programs* (May 2007), attached as **Ex. 44**.

but it is not clear whether that market remains active.[394] Some barriers to a viable market for energy savings credits have been identified, including: (1) high transactions costs, including the cost of EM&V, and (2) the absence of a nationwide standard-setting body for certification of ESCs (as exists for RECs).[395]

The Climate Registry, a nonprofit organization of states, provinces and tribal governments, has proposed that an energy efficiency registry be established to facilitate the use of EE for Clean Power Plan compliance.[396] This registry would serve as a platform for consolidation of EM&V tools, aggregate data for consistent reporting to EPA, and would "provide clear and transparent attribution and ownership of energy savings" to serve as the foundation of a trading platform for energy efficiency credits among states. We support the creation of such a registry, which will ease the administrative burden on states, facilitate stakeholder review, and allow trading of energy efficiency credits which will ultimately expand the market for energy efficiency.[397] Regardless of what system is used, EPA must adopt rules to specify minimum criteria to ensure that EM&V procedures are fully adequate and enforceable and reflect the best demonstrated system.

e. Which Types of Efficiency Activities May Count Toward Compliance?

EPA's Block 4 target is primarily based on evidence that twelve states have either achieved annual incremental savings rates of 1.5 percent (as shown on data reported on EIA Form 861), or have established requirements for utilities to achieve that savings rate.[398] That target reflects savings achieved through EE programs that are supervised by public utility commissions, whether implemented by load-serving utilities or by third-party administrators or state agencies. EPA's target does not include appliance standards, building codes, building energy benchmarking requirements, or other non-PUC-supervised programs, although EPA refers to the availability of such measures as further reason that a 1.5 percent annual target is achievable.[399] EPA chose to base Building Block 4 on PUC-supervised EE programs because data about the savings in those programs have been reliably and widely tracked for years through EIA form 861.[400]

[394] *See* Friedman & Bird, *Energy Savings Certificate Market*, *supra* n. 393, at 9; CRS, *Potential for ESC*, *supra* n.393, at 36.
[395] *See* Friedman & Bird, *Energy Savings Certificate Market*, *supra* n. 393, at 7.
[396] *See* The Climate Registry*, Statement- Establishing an energy efficiency registry as a tool for state compliance under U.S. EPA's Clean Power Plan* (Sept. 22, 2014), attached as **Ex. 45**.
[397] While we do not believe that private-sector EE activities, such as ESCOs, should be eligible for compliance, see infra, we support including protocols for these EE activities in the registry. Those credits would then be available to voluntary markets, and would enable EPA to gather further data on the potential for these activities for when it revisits the 111(d) standards in 2025, as we suggest.
[398] 79 Fed. Reg. at 34,872.
[399] *Abatement Measures TSD* at 5-31.
[400] To the extent that PUC-supervised EE programs have included measures relating to building code implementation, the program data would reflect savings from those measures. Misuriello et al., ACEEE,

PUC-supervised EE programs are an ideal tool for compliance with the Clean Power Plan because they are integral to the load-serving utility's planning about which resources it will use to serve that load. The load-serving utility incorporates the projected savings from these programs into the forecasts that it uses to determine how much and what type of energy and capacity to purchase or supply. The fact that these energy efficiency savings are a system resource, just like generation, is why ratepayers are required to pay for it, just as they would any other resource. Ratepayer-funded EE programs have been widely adopted by legislatures or public utility commissions as a way to reduce electricity rates and avoid having to make major new capacity or transmission investments. In this sense, EE programs that are integrated with the load-serving utilities' planning to serve customers are fundamentally part of the same system as affected EGUs.

EPA has implied that states will be allowed to use building codes, state appliance standards, tax credits and benchmarking requirements as compliance tools.[401] Because we take the position, as stated earlier, that the responsibility for compliance with the Clean Power Plan should rest entirely on the affected EGUs, we believe that the only appropriate compliance measures are those that the owner or operator of an EGU can play a role in adopting or implementing. If EPA makes compliance obligations rest entirely on the affected EGUs, then building code or state appliance standard adoption and implementation should not be allowed as compliance options. To be clear, we support stringent building codes and appliance standards, but because only the state can adopt and enforce these measures, rather than the regulated entity, they are not suitable for CPP compliance under the approach we believe is correct, which holds the affected EGUs responsible for all compliance.[402] These types of measures will be an important tool for the United States in achieving the economy-wide carbon emission reduction targets recently agreed to. For more discussion of the US-China climate agreement, *see* section I.B, *supra*.

Another category of EE activities not accounted for in EPA's Building Block 4 is privately-delivered energy efficiency, such as energy savings performance contracts, industrial energy efficiency and privately contracted-for efficiency that has traditionally not been accounted for in ratepayer-funded energy efficiency programs. In a white paper released in May 2014 by the National Association of Clean Air Agencies ("NACAA"), National Association of Regulatory Utility Commissioners ("NARUC"), and the National Association of State Energy Officials ("NASEO"), urges EPA to "encourage states to develop a clear path for inclusion, crediting, and

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Building Energy Code Advancement through Utility Support and Engagement, Report No. A126 (Dec. 2012).

[401] 79 Fed. Reg. at 34,872.

[402] Insofar as a public utility commission approves measures related to building codes as part of a ratepayer-program, as already happens in some places, those building code–related savings could indirectly be part of the state's Clean Power Plan performance demonstration. *See* Misuriello et al., *supra* n. 400.

administrative review" of these activities.[403] Although EPA's Building Block 4 target is based on ratepayer-funded EE programs, EPA does note that it considered EE activities outside of ratepayer-funded programs as further assurance that a 1.5 percent annual target is achievable. In contrast to building codes and state appliance standards, this category of EE activities is something that the owners and operators of EGUs can implement, by offering the upfront capital needed to weatherize, retrofit, and upgrade buildings for efficiency purposes. In addition, there is a large market of unmet demand for weatherization of low-income homes and small businesses, which affected EGU operators could serve by offering financing or outright grants. Because similar measures are offered through ratepayer-funded EE programs, there are already well-established EM&V protocols for retrofits, weatherization, and replacement of inefficient appliances.

VI. State Plan Considerations

A. Plan Approaches

1. EPA Should Require State Plans to Make Affected EGUs Fully and Solely Responsible for the Emission Reductions Required Under the Rule.

Under the Clean Air Act, owners and operators of affected sources are the entities responsible for meeting the state performance goals that are established under a section 111(d) rule. The Act explicitly provides for state plans requiring affected sources to be the entities legally responsible for achieving the required emission standards: section 111(d)(1) requires that EPA ensure that each state submits a plan that "establishes standards of performance for *any existing source*" within its borders. 42 U.S.C. § 7411(d)(1)(A) (emphasis added). Emission limits that are federally enforceable against affected EGUs clearly fall within the definition of a "standard of performance." *See id.* § 7411(a)(1) (defining a "standard of performance" 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 . . . adequately demonstrated"). This approach has worked well for prior iterations of standards of performance for existing sources, and EPA and state authorities must not stray from the rule's mandate: each state plan must be structured such that the state's fleet of affected EGUs are legally responsible for the full quantity of emission reductions specified in the state plan, and will be subject to federal enforcement actions if they fall short of their obligations under the state plan.

It is true that the Clean Power Plan quantifies the emission reduction obligations of affected EGUs in part by considering the extent to which other sources of generation (or demand reduction) can fill in the gaps created by reduced dispatch of affected units. However, this does not provide a legal nor technical justification for shifting any degree of responsibility for emission reductions away from affected sources onto other entities, such as EE portfolio managers or operators of renewable energy resources. As noted above, section 111(d) is quite

[403] *See* NARUC et al., *Principles for Including Energy Efficiency in 111(d) of the Clean Air Act*, http://naruc.org/Publications/Energy-Efficiency-Principles.pdf.

clear: *sources* are subject to 111(d) standards of performance, and neither EPA nor a state can avoid the statute's command.

Accordingly, states will need to take an active role in crafting state plans that apportion emission reduction obligations across their fleets of affected units and in administering such programs. This point is particularly important for states that choose to adopt a rate-based protocol, since emission reductions achieved through measures other than on-site heat rate improvements—EE, RE, and other techniques that allow for reduced dispatch of affected fossil units—will not be reflected in the emission rates of the affected EGUs. Therefore, rate-based states will need to include a mechanism in their implementation plans that adjusts the emission rate at affected units to account for non-HRI emission reductions. These mechanisms may include trading markets for RECs (which already exist) or energy efficient credits (which are not yet widely used), or programs by which states administratively apportion emission reduction credits across the fleet of affected units. EPA discusses some of these options in the rule preamble. *See* 79 Fed. Reg. at 34,900-02.

We note here that section 111(d) does not prevent states from imposing obligations on non-affected entities so long as it ensures that affected EGUs are ultimately responsible for all emission reductions. For instance, a state plan may require a distribution utility that owns no affected EGUs to sponsor EE measures that will reduce demand from affected facilities in the state. If it fails to implement or fund these EE programs, the state may impose penalties on the utility. What a state may *not* do, however, is shift responsibility *away* from affected EGUs and onto other entities. Affected sources must be subject to federally enforceable emission limits that cover all the required reductions, and states must craft their plans to ensure that affected entities can claim proper credit for emission reductions that are not automatically reflected in their source-specific emission rates.

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

a. Asymmetry Between Mass-Based and Rate-Based Goals Under EPA's Proposal

As EPA has emphasized, one of the Clean Power Plan's key features is to permit states to translate their rate-based emission goals into equivalent mass-based tonnage caps. As we discuss below, EPA must ensure in its final rule that any mass-based translation is truly equivalent to a corresponding rate-based goal. Otherwise, states may pursue compliance pathways that would satisfy a mass-based goal while falling short of a rate-based goal, effectively making end-run around EPA's emission limitation targets.

The rate of CO_2 that is emitted over any period of time by a defined group of affected EGUs can be calculated as the mass of CO_2 emitted by those sources divided by the net electricity they generate over the same period of time. Since the amount of generated electricity is at least as well known as the amount of CO_2 those sources emitted, there should be no difference between a mass-based and rate-based standard, all other factors being equal. Indeed, the relationship between these metrics is provided by a simple equation: mass = rate times generation (M = G*R). If generation remains fixed, then M and R will always be directly proportional; hence, any standard based on one should be no different than a standard based on the other.

However, as the plan is now written, there is a critical asymmetry between rate-based and mass-based standards. Under the current proposal, a state's compliance with EPA's rate-based limit is calculated as a ratio of the direct measurements of CO_2 emitted by affected EGUs during the compliance period to the state's actual "regulated generation" during that same period. By regulated generation, we refer to electricity produced by existing affected EGUs as well as electricity from new and existing renewable units, a percentage of new and preserved nuclear generation, and electricity avoided due to energy efficiency measures. On the other hand, under a mass-based regime, while compliance is based on a state's actual emissions from its affected EGUs, the mass-based limit itself is computed at the outset of the compliance period (i.e., when the state submits its plan to EPA) based either on a fixed level of generation (such as 2012 generation) or an *assumed* or *projected* level of future generation.

This is problematic because a state's projected level of regulated generation will ordinarily be higher than the actual generation level. First, it is technically difficult to predict a state's mix of electricity resources more than a few years into the future. Second, it is similarly difficult to project the rate of demand growth over an extended interval, and states will be more likely to overestimate rather than underestimate future electricity demand in order to reflect economic optimism. Finally, as a result of the M = G*R relationship, higher projections of regulated generation correspond to higher mass-based targets, so states will have an incentive to overestimate future electricity generation in order to relax their compliance burdens.

For these reasons, a state's mass-based limit (based on a level of *projected* generation) will normally be higher (and hence easier to comply with) than a rate-based standard that is based on *actual* generation. According to the M = G*R equation, a larger 'G' will yield a larger 'M' (and thus a higher mass-based cap) if 'R' remains constant. If the state opts to use a fixed generation figure from (for example) 2012, the problem is even more stark, since the pool of regulated generation is assumed to remain constant for the next 18 years, which is almost certainly incorrect.

As an illustration, consider a state that generates all of its electricity from existing fossil-fired EGUs (coal, gas, and oil units). The state then reduces generation from each of its existing sources by 50 percent and replaces the lost electricity with new, unregulated[404] fossil generation. The mass of emissions will be cut in half while the rate is unchanged. By the same token, if generation from each existing source were doubled, the mass would also double while the rate again remained constant. Accordingly, whether a rate-based or mass-based regime is environmentally preferable depends, at least in part, on whether regulated generation (that is,

[404] By "unregulated," we do not mean that these sources are entirely free from regulations; rather, we mean that their emissions and generation are not included in goal-setting or compliance determinations under the Clean Power Plan.

generation that would be included in a state's denominator when calculating its emission rate) will increase or decrease over time relative to expectations.

In a rate-based system that requires reductions over time—such as the Clean Power Plan—the only available compliance option a state has is to replace higher-emitting generation with lower-emitting generation. Under the current proposal, if electricity from coal-fired sources is replaced by generation from *existing* gas units, both the generation and the emissions from those gas units are included in the calculation. However, if *new* gas generation is used to replace existing fossil-fired generation, neither the emissions nor the generation from the new gas units are included in the state's compliance calculation—that is, these sources do not produce "regulated generation." Hence, when a new fossil unit replaces an existing fossil unit, the state will necessarily reduce its regulated CO_2 tonnage while its emission rate will vary only a small amount depending upon the remaining mix of generation. If the retiring unit emits more CO_2 on average than the remaining fleet, the overall rate will go down marginally; if it emits less, the rate will increase marginally. A mass-based protocol therefore encourages states to replace retiring fossil units with new fossil units in a way that a rate-based regime does not.

In contrast to new fossil sources, new renewable sources and EE measures *do* produce "regulated generation"—that is, they are factored into states' rate-based compliance denominators. The more EE and RE a state implements, the more its compliance denominator grows and the faster it approaches its target rate. Accordingly, under a rate-based standard, states have a greater incentive to replace retiring fossil plants with new renewables or EE, which will lower the state's emission rate, as opposed to new gas units, which do not increase the state's compliance denominator. It appears, therefore, that a rate-based regime is environmentally preferable, since it incentivizes states to replace retiring fossil units with RE and EE rather than new gas, whereas a mass-based protocol does not offer the same incentives.

To ensure that the Clean Power Plan achieves the maximum intended emission reductions, EPA must foreclose any possibility that a mass-based plan provides a less rigorous compliance path than its rate-based corollary. Some might argue that including new NGCC generation as both a component of BSER and a compliance option would help address this problem, since states could no longer shift generation from regulated to unregulated fossil units and thereby artificially reduce their mass emissions. However, we urge EPA not to credit new NGCC for either goal-setting or for compliance, since it could encourage states with higher emission targets to opt for new gas units at the expense of new renewables and efficiency, which are environmentally preferable. Furthermore, this approach would not solve the problems inherent in projecting regulated generation years into the future; it would simply add a new category of sources to the pool of what may be considered regulated generation.

We therefore propose that EPA reject any call to adopt new gas for goal-setting and compliance purposes. Instead, we propose a new "accounting" method by which EPA can ensure that rate-based and mass-based targets provide identical environmental benefits. As discussed above, mass and rate are directly proportional according to the equation $M = G*R$. In theory, then, there should be no difference between a standard based on M and a standard based on R so long as 'G' is correctly tabulated. Accurate accounting requires two things. First, 'G' should include the sum total of "regulated generation" in a state—generation from existing affected units, new and existing RE, the designated percentage of a state's nuclear generation, and "negawatts" produced through EE measures. In other words, 'G' is simply the denominator used to calculate a state's compliance rate. Second, 'G' must be updated each year to ensure that a state's projections of regulated generation are accurate, and account for any unanticipated or unprojected reduction in electricity from regulated sources.

In its current form, EPA's proposal falls short in that it does not specify what year's regulated generation should serve as 'G,' nor does it require states to adjust their mass-based targest to account for any unanticipated losses in regulated generation resulting from fossil retirements. These shortcomings permit states simply to shift generation from existing fossil plants to new gas units that have effectively the same emission rate as existing gas units. As written, the current mass-based option reduces the amount of RE and EE that a state will need to comply with its emission targets and all but guarantees that "regulated generation" will decline over time. If EPA instead were to require that states recompute M = G*R each year to capture the actual 'G' that has been produced in the state for that year, each state's state's mass-based and rate-based targets will be environmentally equivalent.

b. The Texas Example

The current generation mix in Texas provides a clear illustration of the phenomenon we describe above. Table 11 depicts the 2012 data for Texas by source category.

Table 11- 2012 Emissions and Generation Data for Texas

Source	Mass Emissions (tons CO2)	Regulated Generation (MWh)	Rate (lbs CO2/MWh)
Coal generation	155,253,012	138,705,138	2,239
CCGT generation	61,978,019	148,010,278	837
O&G steam generation	14,394,951	20,911,868	1,377
Other fossil generation	11,697,941	35,025,953	668
Renewable generation	0	34,016,697	0
Preserved nuclear generation	0	2,291,006	0
TOTAL	**243,323,923**	**378,960,939**	**1,284**

In Table 12, we compare Texas aggregated 2012 data with EPA's targets for 2020, 2020-2029, and 2030. For the rate-to-mass conversion, we set 'G' at Texas's 2012 regulated generation of approximately 379 million MWh. This assumes that Texas's pool of regulated electric generation remains constant between 2012 and 2030. The state's 2030 final targets are highlighted in blue.

Table 12- 2012 Totals and EPA's 2020, 2020-2029, and 2030 Targets for Texas

Target	Mass Emissions (tons CO2)	Regulated Generation (MWh)	Rate (lbs CO2/MWh)
Actual performance data for 2012	243,323,923	378,960,939	1,284
2020 Target (using regulated generation totals from 2012)	176,295,577	378,960,939	930
2020-2029 Interim Target (using regulated generation totals from 2012)	161,713,850	378,960,939	853
2030 Final Target (using regulated generation totals from 2012)	149,844,783	378,960,939	791

As Table 12 illustrates, EPA has set Texas's final rate-based target for 2030 at 791 lbs CO_2/MWh. Setting 'G' at 379 million MWh, 'M'—Texas's mass-based target—equals approximately 150 MMT CO_2 for 2030. Next, we aggregated data from ten existing coal-fired plants that are over 40 years old and therefore nearing retirement age. The data for these plants are provided in Table 13 below.

Table 13- Data for Texas Coal Plants Nearing Retirement Age

Coal Unit Considered for Retirement	Mass Emissions (tons CO2)	Generation (MWh)	Rate (lbs CO2/MWh)
Big Brown	8,290,307	7,276,173	2,279
Fayette Power Project	10,051,589	8,319,871	2,416
Harrington	6,961,820	6,176,011	2,254
Limestone	12,537,786	11,516,465	2,177
Martin Lake	17,048,443	14,755,342	2,311
Monticello	8,729,261	7,383,139	2,365
Sandow No 4	4,902,043	4,356,210	2,251
Tolk	7,745,031	7,574,167	2,045
W A Parish	15,063,387	13,550,222	2,223
Welsh	11,388,893	10,280,099	2,216
Total for "To Be Retired" Coal Units	**102,718,560**	**91,187,699**	**2,253**
Totals for Remaining Coal Units	**52,534,453**	**47,517,439**	**2,211**

We then evaluated two emission reduction scenarios, data for which are depicted in Table 14:

- **Scenario 1:** Texas would implement Building Blocks 1 and 2 and would credit its existing (as of 2012) renewable generation and its preserved nuclear generation, but would neither implement any EE measures nor construct any new RE units, nor would it retire any of the 10 coal plants.

- **Scenario 2:** Texas would retire the 10 coal plants and would replace them with new NGCC units. It would also credit preserved nuclear capacity and 2012 RE generation, but would not otherwise implement any of the four building blocks measures. Hence, there would be no heat-rate improvements, no redispatch, no newly constructed RE, and no EE measures implemented.

Table 14- Data from Emission Reduction Scenarios

Scenario	Mass Emissions (tons CO2)	Regulated Generation (MWh)	Rate (lbs CO2/MWh)
Scenario 1 [Blocks 1 and 2 with 2012 RE and preserved nucelar; no EE or new RE]	185,472,307	378,960,939	979
Scenario 2 [10 coal plant retirements with 2012 RE and preserved nuclear; no HRI, redispatch, EE, or new RE]	140,605,364	287,773,240	977

Table Q illustrates that under a mass-based regime, Texas can achieve significantly greater emission reductions by simply retiring the 10 aging coal plants and replacing them with new NGCC units than by implementing Building Blocks 1 and 2, even though these two scenarios would produce nearly equal results under a rate-based protocol. In fact, Texas can fully comply with and even exceed its mass-based limit of 150 MMT under scenario 2, which would result in net regulated emissions of approximately 141 MMT, even while its emission rate (977 lbs CO_2/MWh) would be significantly higher than its final rate-based target of 791 lbs CO_2/MWh.

Under Scenario 2, overall electricity generation from regulated entities drops from 379 million MWh to 288 million MWh. If the 93 million MWh that had been generated by the 10 retired coal units is replaced by new gas-fired generation, neither the electricity nor the associated emissions will be included when calculating the state's emission rate, since (as discussed above) new gas-fired electricity is not counted as "regulated generation." But unless there is some mechanism that requires Texas to readjust its mass-based goal to account for the fossil retirements, the 91 million MWh factor into the state's calculation of its mass-based goal at the same time that the emissions associated with those 91 million MWh simply disappear from the equation.

c. The Need for Actual Generation Data and a True-Up Requirement

EPA can—and must—rectify this flawed regulatory design by basing each state's mass targets limit on the *actual regulated generation* in that state during the compliance interval, with a period of time after the end of the year to allow sources to "true up" any shortfall by overcomplying or purchasing allowances, similar to the Acid Rain Program's compliance protocol. In the example above, Texas's final mass-based goal of 150 MMT CO_2/year was initially calculated by multiplying the final rate (791 lb CO_2/MWh) by its initially predicted regulated generation of 379 million MWh. Recalculating this figure using the *actual* regulated generation—288 million MWh—would yield a final mass-based target of approximately 114 MMT CO_2/year. The state's final and interim targets would thus be recalculated annually to reflect the actual regulated generation figures, as opposed to a figure predicted at the time the state submits its plan to EPA. This method is the only way of ensuring that the stringency of a state's mass-based program is the same as EPA's rate-based proposal.

Alternatively, one could determine a mass-based limit by projecting regulated generation based on the prior year's figures, rather a long-term projection. Either of these approaches might, in fact, be called "rate-based," as they do not provide a definite and predetermined cap on emissions that remains in place through the duration of the regulatory period.[405] However, planning concerns for states wishing to follow a mass-based approach are no greater than they would be for rate-based states. Instead, the advantage of these approaches is that they still allow trading of mass-based allowances for compliance. It has been argued that mass-based programs provide the certainty of a hard cap on emissions, but in fact, programs such as RGGI are successful only where member states adjust the cap on a reasonably regular basis. The same should be true of EPA's Clean Power Plan, and readjustment must be annual to ensure that rule does not privilege a mass-based approach over rate-based protocol (or vice versa). This approach we recommend would simply identify the glide path for such readjustments.

Compliance planning for both mass- and rate-based programs offer opportunities for states to effectively "game the system" if the planning cycle is overly long. Even program managers operating in good faith are unlikely to incorporate voluntary plant retirements into compliance plans until those retirements are announced by the operators. As indicated above, PUCs engaged in integrated resource planning cannot generally forecast future developments more than a few years into the future with the kind of specificity necessary to inform investment decisions. As we discuss in more detail in Section XIII.A, these factors argue for shorter compliance periods than suggested by the EPA's proposal—perhaps an overall compliance period of 8 years to match the section 111(b)'s review period, with an interim compliance date of 4 years.

It bears noting that various commenters—including EPA in its preamble—have suggested that mass-based approaches are advantageous in that they obviate the need for rigorous EM&V of EE measures that ensure effectiveness, since they determine compliance based only on CO_2 emissions measured at the stacks of affected EGUs. This viewpoint overlooks the fact that a state must determine its regulated generation in order to calculate a mass-based target in the first place. If a state chooses not to verify its EE measures through adequate EM&V procedures, it cannot include those measures the pool of regulated generation—or 'G'—by which it translates its rate target to its mass target through the equation M = G*R. If the state omits those negawatt hours from 'G', its final mass-based target will be lower than it would

[405] Determination of compliance with rate-based programs in any given year necessarily includes determining mass emissions for that year.

otherwise have been, and hence the state will have more difficulty achieving compliance. Accordingly, states wishing to receive credit for their EE measures must partake in EM&V regardless of whether they follow a rate- or mass-based protocol.

d. Our Approach Prevents Double Counting of RECs

Our recommend method of converting rate-based to mass-based goals has an added benefit of preventing states from double counting RE credits. In a rate-based system that uses projected rather than actual regulated generation and that does not require an annual true-up, a state need only show that its mass emissions do not exceed the tonnage cap for the compliance year. A state may have achieved the necessary reductions in part by investing in new renewable generation, but nothing in the rule as written prevents a utility from selling the RECs that are attached to those same renewable sources that have helped the state achieve compliance. Therefore, the purchasing state will receive credit for the REC even after the selling state has used that renewable source to achieve compliance with the standard.

Under our approach, states will need to recalculate their emission targets each year to reflect actual regulated generation, which included any electricity produced by renewable units. If a state has sold a REC linked to any given RE generator, it will not be permitted to include those megawatt-hours in its 'G' figure for the M = G*R calculation, and it will therefore have a more stringent mass-based target. States thus have a choice: they can either sell a REC associated with a renewable unit to another state and receive payment, or they can include the electricity generated by that source during the true-up process to raise their mass ceiling, but they cannot do both. Double counting of RECs is therefore avoided, and the rule achieves greater environmental benefits as a result.

B. Compliance and Enforcement of State Plans

1. Corrective Measures Can Significantly Reduce Compliance Problems, but Only if EPA Provides More Detailed Minimum Requirements for Such Measures.

EPA's proposal to have states build corrective measures into their plans is an essential strategy for reducing the risk of non-compliance with the unusually long averaging times in the Clean Power Plan. Absent some mechanism for ensuring that states remain on track, the proposed 10-year compliance period[406] creates the potential for a pile-up of violations in 2030, when a final determination of compliance with interim goals is made. For EPA to wait until then to require the development of additional plan measures would unnecessarily delay emission reductions, and the need for states to incorporate remedial measures into their plans would only add to this delay. The failure to achieve projected emission performance in the early years of a state plan may also indicate structural problems with the plan (e.g., inaccurate modeling results) that could render compliance with the state goals impossible. Moreover, because EPA proposes to allow states to define their own emission reduction trajectories between 2020 and

[406] As discussed in section XIII.A, *infra*, we support an accelerated and shortened compliance schedule.

2029, there is a risk that many state plans will defer making the most significant cuts until the later years of the interim period. Procrastination of this nature, together with any unaddressed failures to achieve the more modest early reductions, could lead to a critical shortage of available measures in the later years to ensure compliance with EPA's targets.

Because corrective measures have such an important role to play in ensuring that states achieve the CPP's performance goals, additional requirements for corrective measures are crucial if they are to be effective compliance tools. EPA must expand corrective measures to all plans, set minimum thresholds and standards for the adoption, activation, and implementation of these measures, and providing greater transparency in exposing the causes of any deficiencies in state plan performance.

All state plans must ensure that affected EGUs are responsible for all the emission reductions required under the rule and thus subject to federal enforcement actions, as discussed above. To supplement to federal enforceability, corrective measures are necessary to ensure that plan deficiencies are fixed swiftly and soon after they occur. We are concerned, however, that EPA underestimates the full value of corrective measures. Under the proposed rule, "self-correcting" plans need not include corrective measures. *See* 79 Fed. Reg. at 34,952 (proposed 40 C.F.R. § 60.5740(a)(7), requiring corrective measures only for plans that do not rely on emission limits on affected EGUs to achieve all state goals). EPA describes self-correcting plans as those which "would assure interim performance and full achievement of the state plan's required level of emission performance through requirements that are enforceable against affected EGUs." *Id.* at 34,907. However, just because an emission standard in a state plan may be enforceable against affected EGUs does not mean that violations of the standard will actually be enforced in a way that assures the state plan's emission performance goals are achieved. For example, an enforcement action may result only in civil penalties and not in reductions in future emissions from an EGU. In that case, the excess emissions from the violating EGU may throw the state off course from achieving a performance goal. Future year requirements for affected EGUs in the state plan may need to be adjusted to correct this deviation, and such adjustments are functionally no different than the corrective measures EPA has proposed for any plans that are not self-correcting.

To effectively serve their intended purpose, corrective measures must be actionable when a state submits its plan to EPA. The agency has proposed to leave to the states the decision whether to adopt corrective measures into their regulations prior to submittal, or whether to wait until after a deficiency is discovered before taking legislative or administrative action to codify the corrective measures in the plan. The proposed rule offers that "it may be challenging for states to fully adopt corrective measures in advance to address the possibility that their plan will not perform as projected." 79 Fed. Reg. at 34,907. However, even if states have difficulty identifying potential corrective measures, EPA has not identified what about the mere codification of those measures—in tandem with the adoption into state codes of other plan provisions—poses a special challenge. Furthermore, EPA recognizes that "[l]egislative and/or regulatory action to adopt corrective measures after a deficiency is discovered will take significant time." *Id.* There is no reason to allow states to delay the adoption of corrective measures until after a deficiency occurs, or to make the implementation of corrective measures that states have already identified in their plans unenforceable. By analogy, the Act requires SIPs for nonattainment areas to "provide for the implementation of specific measures to be undertaken" if the area fails to make timely progress toward attainment of standards, and further requires that such measures "shall be included in the plan revision as contingency measures to take effect in any such case *without further action by the State or the Administrator*." 42 U.S.C. § 7502(c)(9)(emphasis added). The same sort of approach is warranted for the section 111(d) plans at issue here, if they are to ensure the "best system" of emission reductions. *See also id.* § 7511a(c)(9).

EPA must also establish a deadline for states to begin implementing corrective measures once their actual emissions or emission rate exceeds projections. Although the agency has not proposed such a deadline in the rule proposal, *see* 79 Fed. Reg. at 34,952 (proposed 40 C.F.R. § 60.5740(a)(7)(ii), requiring only that state plans include "a process and schedule for implementing such corrective measures"), it suggests that two years after a state reports a deficiency in its annual performance update may be a suitable deadline. *Id.* at 34,912. Because states will likely have notice of the deficiency well in advance of the reporting date, an additional two years for implementing corrective measures is unnecessary and irrational. As noted above, the Act requires immediate triggering of contingency measures where nonattainment areas fail to meet progress targets. There is no reasoned basis for allowed a more delayed approach under section 111 plans. Only the incremental corrective measures would need to be implemented anew, not the entirety of the plan. Any delay longer than six months would therefore be excessive for undertaking corrective action.

Another facet of this compliance approach that requires clarity is the minimum amount of corrective measures that plans must include. EPA's proposal requires that such measures be available to remedy plan deficiencies, but has not specified any minimum requirements. 79 Fed. Reg. at 34,952 (proposed 40 C.F.R. § 60.5740(a)(7)(ii)). The agency also seeks comment on whether corrective measures must be sufficient to remediate deficiencies or merely to ensure the future achievement of the state's goals. *See* 79 Fed. Reg. at 34,908. At a minimum, corrective measures must serve to fully remedy any shortfall in plan performance as measured over the two-year period over which EPA will evaluate states' progress in meeting their goals. Therefore, if EPA retains its proposed 10 percent deficiency as the trigger for corrective measures, states must develop corrective measures that achieve improvements in excess of 10 percent of their annual targets. Otherwise, the corrective measures would not fully correct the deficiency that triggered them. To ensure the availability of sufficient corrective measures to avoid the need for a SIP call, EPA should require state plans to include fully adopted corrective measures adequate to provide at least double the deficiency trigger percentage for each year of the plan, plus an additional menu of contingency measures that will be triggered progressively if the doubled trigger percentage is not sufficient to compensate for the full shortfall.

EPA must also clarify that the criteria for corrective measures are as rigorous as those concerning plan measures that are not contingent on a deficiency. For example, the effectiveness of the corrective measures selected for inclusion in the plan should be evaluated through the same process that states use for other plan projections: they must be quantifiable, verifiable, non-duplicative, permanent, and enforceable. Additionally, monitoring, reporting, and recordkeeping requirements for corrective measures must be sufficient to assure compliance.

The trigger for corrective measures must be set low enough to assure compliance. Although the agency has proposed a 10 percent deficiency as the trigger for corrective measures, it has solicited comment on a range of values, suggesting that five to 15 percent may be appropriate for states with corrective measures adopted into their regulations and five to 10 percent for states without codified measures. *See id.* at 34,907. Because many states are unlikely to adopt plans that overcomply with EPA's goals, it is important to keep states as close as possible to the emission reduction trajectory laid out in their implementation plans. Even a five percent deficiency may prove impossible to overcome without additional plan measures to make up the deficit in subsequent years.

Finally, EPA has proposed that a state would only have to determine and report its reasons for deficient performance if it elects to wait until after it discovers the deficiency before incorporating the plan's corrective measures into its regulations. *Id.* EPA has not justified this stance, and information about the cause of the shortcoming would have significant value. Publishing the reasons for deficient performance could provide early notice to other states and the public of problems that may surface in many plans, such as lower-than-expected benefits from certain energy efficiency incentive programs for particular kinds of equipment. The benefits this information outweigh the modest analytical and reporting burden that it may impose on states who have experienced a plan deficiency, and EPA should require all states that report a deficiency to make public its cause.

2. Unit-Specific Evaluation Periods Should Be One Year for All Affected EGUs, with States' and EGUs' Progress Reported to EPA Annually.

EPA has proposed to allow differing unit-specific evaluation periods for rate-based and mass-based state plans (up to one year for the former and up to three years for the latter). *Id.* at 34,956 (proposed 40 C.F.R. § 60.5820 definition of "compliance period").[407] Although not clearly stated, EPA's rationale for this disparity appears to be the fact that the mass-based RGGI program utilizes a three-year evaluation period, whereas a three-year averaging time for emission rates would be execssive. *See* 79 Fed. Reg. at 34,881, 34,922. However, even if it were appropriate for EPA to tailor its emission guidelines to fit the programs states have already

[407] By "evaluation period," we mean the interval over which a state determines whether an affected EGU has complied with an applicable rate- or mass-based emission target included in the state plan. EPA refers to these unit-specific evaluation periods as "compliance periods" in its proposed regulations. However, throughout these comments, we use the term "compliance period" to refer to a different concept: the interval during which the Clean Power Plan targets will apply (2020-2030 or 2020-2025 under the current proposal). To avoid confusion, we refer to the unit-specific interval for determining compliance with an emission target as an "evaluation period" instead of a "compliance period."

adopted, accommodating the enforcement periods in existing state programs could seriously undermine the enforceability of the CPP's state goals.

EPA has proposed requiring states to report performance data to the EPA annually by July 1, and that beginning in 2022, states would include in their reports a comparison of actual performance to projected performance, with each comparison covering the preceding two-year interval. Allowing some states to apply a three-year evaluation period to their affected sources, in tandem with the proposed rule's requirement that affected EGUs report hourly CO_2 emissions and net electric output *for each evaluation period*, *see* 79 Fed. Reg. at 34,955 (proposed 40 C.F.R. § 60.5805(c)), would render unworkable the annual comparison of actual and projected performance under the plan. Apparently recognizing this, the proposed rule states that EPA "may also approve regular, periodic emission comparison checks with a different frequency or comparison period to reflect the design of a state's programs (e.g., compliance periods for EGUs under an emission limit)." 79 Fed. Reg. at 34,907. In other words, the comparisons that are crucial to evaluating the success of state plans in reducing emissions may only be required every three years for some states.

The proposed rule does not explore the drawbacks of allowing less frequent comparison checks for some states, despite the significant value in maintaining a uniform approach with annual comparisons. The annual comparison checks that EPA has proposed will provide a crucial opportunity for the agency and the public to assess the progress of all states in meeting their goals. Staggering some of these checks or using different comparison periods would complicate the task of ensuring the integrity of the reported results, by (for example) identifying possible instances of double-counting, particularly for EE or RE measures with interstate effects. Requiring a unit-specific evaluation period of one-year for all states may require changes to some existing state programs, but these changes would be modest and are necessary to generate a uniform set of performance data for assessing the progress of all states in meeting the CPP's goals.

Similarly, EPA's suggestion to require state progress reports only every two years overlooks the crucial role that annual reporting plays in informing the public of the Clean Power Plan's success or failure toward achieving its goals. *See id.* at 34,914. Each element of the annual report described in proposed 40 C.F.R. § 60.5815 is needed to present an accurate picture of states' progress.

Finally, EPA requested comments on whether electronically submitted reports from affected entities should be provided to EPA or only to the relevant state authorities. *See id.* at 34,910-11. Requiring affected sources to report to EPA in addition would help the public evaluate the progress that individual units achieve toward reducing emissions, the performance of different states, and the effectiveness of the plan as a whole. A central clearinghouse of unit-specific data would help interested citizens avoid having to negotiate the multiple different interfaces and software functionalities on which state agencies may rely. For these reasons, EPA should require annual state progress reports and should require affected EGUs to submit electronic reports to states and EPA alike.

3. EPA Should Require Direct CEMS Monitoring of CO_2 Emissions.

EPA proposes to allow facilities to determine compliance with an applicable standard by either monitoring emissions directly or by estimating emissions based on fuel consumption. Proposed 40 C.F.R. §§ 60.5535, 60.5540.[408] Direct monitoring of emissions, especially using continuous emission monitoring systems ("CEMS"), is generally more accurate than estimations of emissions using fuel consumption, as EPA has previously acknowledged.[409] In fact, all or virtually all existing coal-fired plants already use CEMS to comply with existing reporting requirements under the Clean Air Act's Acid Rain Program and Greenhouse Gas Reporting Rules.[410] Accordingly, requiring coal plants to use CEMS for the Clean Power Plan will improve reporting accuracy while imposing little (if any) additional burden on industry. We urge EPA to require CEMS not only at coal plants, but at all units reporting CO_2 emissions under the CPP.

The value of CEMS data is illustrated by analysis of plants for which EPA has both CEMS and fuel-based emission estimates. Power plants within the Clean Air Act's Acid Rain Program report CO_2 emissions to the EPA, and essentially all, if not all, coal-fired plants do so using CEMS, while most oil- and gas-fired plants use site-specific emissions calculations.[411] The Energy Information Administration ("EIA") also calculates emissions for these plants, but uses fuel consumption data rather than the CEMS information.[412] These parallel data sets allowed U.S. Geological Survey scientists to compare measured and estimated emissions for 2,900 plants, including the 828 plants that report using CEMS measurements (which are almost entirely coal plants).[413] The researchers found significant divergences between the two data sets. Overall, the fuel consumption data provided an average emission rate estimate that was 4.6 percent lower than the CEMS data.[414] This result masks even greater divergences in estimates at

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[408] It appears that EPA inadvertently omitted a third provision relating to using fuel consumption to estimate emissions. Proposed 40 C.F.R. § 60.5535(c) refers the option of "determin[ing] . . . C02 mass emissions are by monitoring fuel combusted in the affected EGU and periodic fuel sampling *as allowed under § 60.5525(c)(2)*," but the proposal does not contain a section 60.5525(c)(2).
[409] *See, e.g.*, EPA, Regulatory Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Proposed Rule (Sept. 2009), *available at* http://www.epa.gov/ghgreporting/documents/pdf/archived/EPA-HQ-OAR-2008-0508-2229.pdf, at 5-15 to 5-21**;** Schakenbach et al., U.S. Office of Atmospheric Programs, *Fundamentals of Successful Monitoring, Reporting, and Verification under a Cap-and-Trade Program,* 56 J. of the Air & Waste Mgmt. Ass'n 1576, 1581 (Nov. 2006), *available at* http://www.epa.gov/airmarkets/cap-trade/docs/fundamentals.pdf.
[410] Ackerman & Sundquist, *Comparison of Two U.S. Power-Plant Carbon Dioxide Emissions Data Sets*, 42 Environmental Science & Technology 5,688,5,690 (June 2008), *available with password at* http://pubs.acs.org/doi/abs/10.1021/es800221q ("Currently, all coal-fired units use CEM systems").
[411] See 40 C.F.R. §§ 75.10(a)(3) (CO_2 monitoring options); 75.13 (CEMS requirements).
[412] Ackerman & Sundquist, *supra* n. 410, at 5,688.
[413] *See id*. at 5,689.
[414] *Id.*

individual plants.[415] The discrepancy is likely due to the inherent inaccuracy of fuel sampling for coal plants. Samples are typically taken from different parts of the fuel pile, and the calculations do not take into account environmental conditions at the time of fuel use, such as wet or frozen coal.

As for natural gas, EPA's fuel sampling procedures include a determination of the relationship between fuel flow and load for the unit.[416] This requires the operator to measure the fuel consumption and generation of the unit on an hourly basis for 168 hours, then to calculate the average fuel consumption per unit of generation. However, EPA's procedure allows a source to exclude as "nonrepresentative" any hour in which the unit is "ramping up or down" (defined as a variation in load of greater than 15 percent) or is operating at low load (defined as any hour in which the load is in the lower 25 percent of the units normal range of operation). The effect of this procedure is to effectively exempt periods of low or changing load from regulation. As EPA has previously recognized, emission rates are ordinarily higher during these periods of operation than during steady-state, near full-load conditions. Since the excess CO_2 generated under these conditions contributes to climate change and can be reduced by minimizing low load and ramping activities, these emissions should be included in determining the unit's emissions.

4. Affected Units Should Be Required to Submit Engineering Analyses and Reference Method Test Results to Confirm the Effectiveness of Compliance Measures.

Under the Acid Rain Program, sources were afforded the opportunity to choose a baseline year from among several years for determining the baseline emission rate. If EPA were to adopt this approach for the Clean Power Plan, sources would likely select the year with the highest emitting rate, and any emission reductions under Block 1 via heat rate improvements would be largely illusory. However, choosing either the average or the reported lowest emission rate, which might be five percent less than the average rate, would lead to concerns that the requirement is infeasible. Moreover, the heat rate achieved by the unit is partially dependent on the load factor of the unit, which is a function of weather, dispatch priority, and other factors.

To address these concerns, we suggest that each source should be required to submit an engineering analysis of the measures that it intends to undertake to achieve the required

[415] The study authors expressed this overall variability by calculating the absolute relative difference. The systemic 4.6 percent underestimate included above is the "signed relative difference", which is generated by adding up all the paired differences, positive or negative (e.g., -5+5+1=1) and dividing by the number of data pairs – and the average absolute difference, which is calculated by adding the absolute value of those differences (e.g. 5+5+1=11), and so measures the total variation between the pairs because oppositely-signed differences do not cancel each other out. Using these methods, while the signed relative difference between matched pairs was 4.6 percent, the corresponding absolute relative difference was 17.1 percent.

[416] Alternatively the source operator may calculate the gross heat rate of the unit, but may still exclude ramping and low load operation. 40 C.F.R. Pt. 75, Appendix D 2.1.7

efficiency improvement and conduct reference method tests before and after implementing those measures to document that the required improvement has been attained.[417] To aid in identifying the most cost-effective hardware upgrades and to minimize gaming by regulated entities, detailed reporting of the cost and performance of engineering upgrades should be required and made publicly available. Thereafter, CO_2 CEMS and enhanced fuel input and electrical output monitoring would be employed, along with annual reference method testing, to document that the required improvement is being maintained. A Compliance Assurance Monitoring ("CAM") response plan would require an engineering analysis and additional measures to be adopted if the source's compliance margin fell below a set value.

5. EPA Should Strengthen the Record Retention Requirements.

EPA's proposed rule would require affected sources to retain compliance records on site for only two years, after which records could be retained "off-site and electronically." 79 Fed. Reg. at 34,955 (proposed 40 C.F.R. § 60.5805(b)(1)). The effect of this seemingly innocuous provision is to reduce the efficacy of onsite inspections and make compliance determinations only possible through information requests authorized under section 114 of the CAA and analogous state provisions (where they exist). Section 114 information requests by EPA's enforcement office have often been the subject of controversy, as well as attempted interference by Congress.[418] State and local officials are particularly reliant on onsite inspections to ensure regulatory compliance. If they have the authority to conduct document-intensive offsite investigations, they use it only rarely. The prospect of essential information being stored at a remote location, which may lie outside the jurisdiction of the state or local authority, and in formats that may be difficult to access, presents a significant obstacle to enforcement (including citizen enforcement pursuant to section 304 of the Act), especially in the current era of shrinking EPA and state agency enforcement budgets.[419] Moreover, EPA has not identified any particular (or even generalized) basis for its proposal to permit offsite storage after two years. Technological advances have reached the point where a year's worth of data, including scanned PDF documents, can be stored on a single flash drive, negating earlier arguments about space requirements.

To facilitate the expeditious review of needed information, EPA needs to adopt additional requirements covering record retention. For example, under the subpart 98 reporting program for GHGs, records may be stored off site only "if the records are readily available for expeditious inspection and review." 40 C.F.R. § 98.3(g). In addition, for any records

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[417] Such tests might be conducted at two or more load points, e.g., 100 percent and 80 percent.
[418] EPA's Office of Air and Radiation has also demonstrated a reluctance to apply to the Office of Management and Budget for permission under the Paperwork Reduction Act to employ section 114 requests to obtain information needed for rulemaking development.
[419] EPA's Fiscal Year (FY) 2014–2018 Strategic Plan announced significant and troubling cuts to the agency's enforcement program, including reductions in in-person inspections and civil cases. *See* EPA, *Fiscal Year 2014–2018 EPA Strategic Plan* (Apr. 10, 2014) at 73, *available at* http://www2.epa.gov/sites/production/files/2014-09/documents/epa_strategic_plan_fy14-18.pdf.

stored electronically, “the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents.” *Id.* To properly implement the CAA’s citizen suit provisions, EPA must clarify that “readily available” means available on demand, not just to EPA, but to state and local authorities, irrespective of jurisdiction over the site where the records are stored, and to the general public. *See* 42 U.S.C. § 7410(a)(2)(F)(requiring states to correlate emissions monitoring reports “with any emission limitations or standards established pursuant to this chapter, *which reports shall be available at reasonable times for public inspection*”) (emphasis added). Because these requirements apply to CO_2 emissions data from power plants under the GHG reporting program, extending their application to the Clean Power Plan will ensure consistent requirements and will impose little, if any, additional burden. *See id.* § 98.47.

6. EPA Should Confirm What Actions It Must and Will Take if a State Plan or Portion Thereof Is Not Submitted or Cannot Be Approved.

EPA has proposed that in the absence of an approvable state plan, the agency will develop a federal plan “according to [40 C.F.R. § 60.27.]” 79 Fed. Reg. at 34,951 (proposed 40 C.F.R. § 60.5720). Although the proposed rule therefore appears to apply the deadlines for a federal plan codified in section 60.27, EPA should clarify in the final rule that is the case. Section 60.27(d) provides that EPA must promulgate a federal plan “within six months after the date required for submission of a plan or plan revision” if the agency determines that a state has failed to submit a plan or plan revision, or if it disapproves any portion of a state plan or revision. Because the proposed rule only supersedes the requirements of subpart B of 40 C.F.R. Part 60 to the extent they are inconsistent with the proposed rule, *see* 79 Fed. Reg. at 34,951 (proposed 40 C.F.R. § 60.5700), the federal plan deadline in 40 C.F.R. § 60.27(d) appears to govern any federal plan needed under the CPP. This six-month deadline also appears to provide the timetable for state action to correct any plans that EPA has disapproved, in whole or in part. EPA should clarify that the deadline also governs state action to amend any plans determined by EPA to be inadequate subsequent to their initial approval by the agency.

7. Criteria for Approving State Plans/Required Elements of Plans

State plans must include a showing that the state will have adequate resources and authority to implement and enforce the plan. EPA has proposed that state plans must include “[m]aterials demonstrating the state’s legal authority to carry out each component of its plan,” but has not expressly included a requirement that states also have adequate resources to implement and enforce the plan’s requirements. 79 Fed. Reg. at 34,952 (proposed 40 C.F.R. § 60.5740(a)(11)(i) For example, EPA’s Part 51 regulations require that state implementation plans must include

> a description of the resources available to the State and local agencies at the date of submission of the plan and of any additional resources needed to carry out the plan during the 5-year period following its submission. The description

must include projections of the extent to which resources will be acquired at 1-, 3-, and 5-year intervals.

40 C.F.R. § 51.280*; see also* 42 U.S.C. § 7410(a)(2)(E). A similar demonstration should be required for plans under the CPP. *Id.* Merely having the legal authority to implement and enforce plan provisions is not sufficient if the state lacks the resources (or will not commit adequate resources) to carrying out the plan.

8. EPA Should Reject the Option of Granting Conditional Approval of State Plans.

EPA seeks comment on using the Clean Air Act's conditional approval mechanism, 42 U.S.C. § 7410(k)(4), for state plans. As described in the proposed rule, this would allow EPA to approve state plans that fail to meet all requirements, so long as the state commits to curing the deficiencies within one year. *See* 79 Fed. Reg. at 34,916-17. Because EPA is proposing to require states to submit their initial plans in June 2016, there should be no need to apply the Act's conditional approval process to the state plans proposed to meet the Clean Power Plan's emission goals. EPA will have an opportunity to review the state's initial plan to identify issues that may foreclose approval if adopted into the plan. Making conditional approvals available would only reward states that fail to submit plans meeting all requirements by the applicable deadline. Moreover, the extended one-year timeframe for states to correct their conditionally approved plans would conflict with the six months EPA's current regulations provide for states to address the presumably more wide-ranging plan deficiencies that result in disapproval of the plan by EPA.

9. EPA Must Amend Its Proposed Regulations to Ensure That Emissions Standards Are Enforceable by Citizens.

EPA has proposed a regulation which would mandate that each state plan include emissions standards that satisfy certain criteria, including the requirement that emission standards must be "enforceable with respect to each affected entity." Proposed 40 C.F.R. § 60.5780(a). The proposed regulation provides that an emission standard is "enforceable against an affected entity if," among other things, "[t]he Administrator and the state maintain the ability to enforce violations and secure appropriate corrective actions pursuant to sections 113(a) through (h) of the Act." *Id.* § 60.5780(f). The proposed regulation omits any requirement that the emission standards are enforceable by citizens. The Clean Air Act provides that citizens may sue for violation of "an emission standard or limitation under this chapter," 42 U.S.C. § 7604(a), and defines "[e]mission standard or limitation under this chapter" to include "any requirement under section [111] or [112] of this title," *id.* § 7604(f)(3). However, if the state plans establish emission standards without ensuring that citizens have the ability to enforce violations and secure appropriate corrective actions pursuant to section 304 of the Act, citizens may not be able to enforce those standards as a practical matter. EPA must cure this omission.

Correcting the proposed regulations by including a requirement that emission standards be enforceable by citizens would also be consistent with longstanding EPA practice, as reflected in the existing enforcement guidance which the proposed rule describes as "serv[ing] as the foundation for the types of emission limits that the EPA has found can be enforced as a practical matter." 79 Fed. Reg. at 34,909. Specifically, the guidance provides that emission reductions that create obligations for sources are considered enforceable if, among other things, "[c]itizens have access to all the emissions-related information obtained from the source [and] can file suits against the source for violations."[420] Similarly, reductions achieved through energy efficiency or renewable energy actions for which a party other than a source bears responsibility are considered enforceable if, among other things, "[c]itizens have access to all the required activity information from the responsible party [and] can file suits against the responsible party for violations."[421]

VII. Environmental Justice

Minority and low-income communities bear a disproportionate risk from climate change. The IPCC's Fifth Assessment Report concludes that climate disruption will hit low-income neighborhoods and people of color the hardest. According to the IPCC, "[m]any key risks constitute particular challenges for the least developed countries and vulnerable communities, given their limited ability to cope."[422] These risks are both health-related and socio-economic. In the United States, minority and low income communities often live near dirty power plants and other industrial facilities. For example, 60 percent of African Americans and Latinos nationwide reside in communities with toxic waste sites. These communities are also more likely to live near busy highways, all of which leads to higher risk of air pollution-based illnesses.[423] Researchers have found that African-Americans and Latinos are also more likely to reside in areas vulnerable to climate change impacts such as sea-level rise, flood risk, and wildfire risk, and that median household incomes are inversely related to these vulnerability risks.[424] As climate change worsens, minority and low income communities will also bear the burden of spending higher proportions of their income as a result of rising food prices or increased water scarcity.[425]

The Clean Power Plan has a great potential to reduce carbon emissions. Carbon pollution standards aimed at reducing CO_2 emissions from existing power plants can also

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[420] EPA, *Guidance on State Implementation Plan (SIP) Credits for Emission Reductions from Electric-Sector Energy Efficiency or Renewable Energy Measures* (Aug. 2004), *available at* http://www.epa.gov/ttn/oarpg/t1/memoranda/ereseerem_gd.pdf, at 6.
[421] *Id.*; *see also* 79 Fed. Reg. at 34,909 n. 283 (citing this guidance).
[422] IPCC, *Climate Change 2014: Impacts, Adaptation, and Vulnerability: Summary for Policymakers* (2014), at 13.
[423] Truong, V., *Addressing Poverty and Pollution: California's SB 535 Greenhouse Gas Reduction Fund*, 49 Harvard Civil Rights-Civil Liberties L. Rev. 493, 498 (2014), attached as **Ex. 46**.
[424] English et al., *Racial and Income Disparities in Relation to a Proposed Climate Change Vulnerability Screening Method for California*, The International Journal of Climate Change: Impacts and Responses, Vol. 4, Issue 2 (Apr. 2013), attached as **Ex. 47**, at 1-18.
[425] Truong, V., *Addressing Poverty and Pollution: California's SB 535 Greenhouse Gas Reduction Fund*, *supra* n. 423.

reduce emissions of criteria and hazardous air pollutants, including sulfur dioxide (SO_2), nitrogen oxides ("NOx"), particulate matter ("PM"), and mercury ("Hg"). SO_2 causes the formation of fine particle pollution ("$PM_{2.5}$") and NOx is an ozone ("O_3") precursor. These co-pollutants contribute to increased risk of premature death, heart attacks, increased incidence and severity of asthma, and other health effects. They also contribute to acid rain, over-fertilization of ecosystems, ozone damage to trees and crops, and the accumulation of Hg in fish. Policies intended to address climate change by reducing CO_2 emissions that also decrease emissions of SO_2, NOx, and $PM_{2.5}$, can have significant co-benefits.[426]

In order to ensure that the most vulnerable communities receive the benefits from a comprehensive policy to reduce carbon emissions and address climate change impacts, the Clean Power Plan must also address the environmental justice aspect of the equation. It is critical for EPA to adopt a holistic approach that recognizes multiple dimensions, including co-pollutant implications and local communities' growth. Thus, care must be taken to ensure that environmental justice communities do not experience increased levels of pollution as a result of the implementation of measures that increase the utilization of certain affected sources. Likewise, these communities can, and must benefit from the positive environmental and health effects that will result from the decreased utilization of dirty power plants and the development of renewable energy generation.

As we describe below, in order to properly integrate environmental justice concerns into the Clean Power Plan, EPA must prepare an environmental justice analysis of the rule, as required under Executive Order ("EO") 12898. Such an analysis will help to ensure that the different compliance measures selected by states under their plans do not cause adverse impacts, and actually benefit minority and low income populations.

Environmental protection is also a civil rights and social justice issue.[427] EPA must ensure that state agencies that receive federal funding under Title VI of the Civil Rights Act comply with their obligation not to discriminate on the basis of race, color, or national origin. Although EPA and the federal government have taken great steps to bring environmental justice issues to the forefront, minority and low income communities continue to face great environmental and

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[426] Driscoll et al., *Co-Benefits of Carbon Standards, Part 1: Air Pollution Changes Under Different 111d Options for Existing Power Plants*, Harvard School of Public Health/Syracuse University (May 27, 2014), attached as **Ex. 48**, at 2.

[427] Civil rights are just one part of human rights. Every individual has a human right to be treated fairly and equally by state and private actors, to enjoy their rights to health, food, equal pay, and decent working conditions, among others. Environmental justice should contribute to further these rights. *See, e.g.*, Harden, M., Advocates for Environmental Human Rights, *The Need for Human Rights Advocacy to Overcome Injustice: Lessons from the Environmental Justice and Climate Justice Movement*, U.S. Human Rights Network (Dec. 5, 2013), *available at* http://www.ushrnetwork.org/sites/ushrnetwork.org/files/environment_justice_framing_paper_-_ushrn.pdf.

socio-economic burdens.[428] This year, which marks the 20th anniversary of EO 12898 and the 40th anniversary of the Civil Rights Act, EPA should take concrete actions to address these challenges in the Clean Power Plan.

EPA also needs to make clear that emission standards that would allow uncontrolled or poorly controlled emissions from individual sources are not permissible as Section 111(d) emission guidelines for pollutants with localized health and environmental impacts. Finally, for states that opt to comply with the Clean Power Plan through trading of renewable energy credits or CO_2 allowances, EPA must establish guidelines for states to effectively integrate environmental justice concerns into the design of these programs in a manner that restricts trading practices that could exacerbate hotspots and that provides for investments in clean energy and the revitalization of these communities.

A. EPA is Required to Perform an Environmental Justice Analysis of the Clean Power Plan Pursuant to Executive Order 12898.

Executive Order ("EO") 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, provides that "[t]o the greatest extent practicable and permitted by law … each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations in the United States." Exec. Order No. 12898, § 1-101. In addition, under the Order, all federal agencies, including EPA, "shall collect, maintain, and analyze information assessing and comparing environmental and human health risks borne by populations identified by race, national origin, or income … [and] shall use this information to determine whether their programs, policies, and activities have disproportionately high and adverse human health or environmental effects on minority populations and low-income populations." *Id.* § 3-302(a).[429]

The language of §§ 1-101 and 3-302 indicates that EPA is required to perform an analysis to identify and address adverse impacts on minority and low-income populations from the Clean Power Plan, "to the greatest extent practicable and permitted by law." *Id.* § 1-101. *See Coal. for Advancement of Reg'l Transp. v. Fed. Highway Admin.*, 2014 WL 3882677, at *16 (6th Cir. Aug. 7, 2014) (recognizing compliance with the "procedural and substantive *requirements* for evaluating environmental justice impacts in Executive Order 12898") (emphasis added); *Mid States Coal. for Progress v. Surface Transp. Bd.*, 345 F.3d 520, 541 (8th Cir. 2003) ("[t]he purpose of an environmental justice analysis is to determine whether a

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[428] *See, e.g.*, Bullard et al., Barbara Jordan-Mickey Leland School of Public Affairs, Texas Southern University, *Environmental Justice: Milestones and Accomplishments: 1964-2014* (Feb. 2014), *available at* http://www3.law.harvard.edu/orgs/els/files/2014/02/Environmental-Justice-Milestones.pdf.

[429] Indian tribes are entitled to the same protections discussed in this section. We will address such protections in our comments to EPA's supplemental proposal to the Clean Power Plan regarding carbon pollution standards for existing power plants in Indian Country and U.S. territories.

project will have a disproportionately adverse effect on minority and low income populations.").

Further, "incorporating environmental justice into rulemaking" is one of EPA's focus areas under its "Plan EJ 2014," the agency's roadmap for integrating environmental justice into its programs and policies.[430] The EPA's *Action Development Process: Interim Guidance on Considering Environmental Justice During the Development of an Action* ("ADP Interim Process Guide") and the draft *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis* ("EJ Technical Guidance"), the latter which EPA recently issued for public comment,[431] "provide direction on how regulatory actions can be responsive to E.O. 12898 as well as EPA's EJ policies[432] and Plan EJ 2014."[433]

EPA has not performed the analysis required by Section 1-101 of the Order and the agency's EJ policies.[434] The agency only highlights the co-benefits of the Clean Power Plan in terms of emissions reductions from criteria and hazardous air pollutants, as detailed in its Regulatory Impact Analysis, and then states that, because it "cannot exactly predict how emissions from specific EGUs would change as an outcome of the proposed rule due to the state-led implementation … it is not practicable to determine whether there would be disproportionately high and adverse human health or environmental effects on minority, low income, or indigenous populations from this proposed rule." 79 Fed. Reg. at 34,950.

However, EPA does identify two ways in which the proposed guidelines may result in increased emissions of criteria or hazardous air pollutants. First, coal-fired EGUs that increase their utilization due to the implementation of supply-side efficiency improvements may increase their emissions of criteria and hazardous air pollutants. EPA concludes that it "has considered the potential for such increases and the environmental justice implications of such

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[430] EPA, Office of Environmental Justice, *Plan EJ 2014* (Sept. 2011), *available at* http://www.epa.gov/environmentaljustice/resources/policy/plan-ej-2014/plan-ej-2011-09.pdf, at 4-5.

[431] *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis*, 78 Fed. Reg. 27,235 (May 9, 2013).

[432] EPA's EJ policies issued pursuant to EO 12898 prior to these guidance documents include: *The EPA's Environmental Justice Strategy* (1995); *Environmental Justice Implementation Plan* (1996); *Environmental Justice: Guidance Under the National Environmental Policy Act* (1997); *Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses* (1998); *Toolkit for Assessing Potential Allegations of Environmental Justice* (2004); and *Memo from Stephen L. Johnson: Reaffirming the U.S. EPA's Commitment to Environmental Justice* (2005). *See EPA's Action Development Process: Interim Guidance on Considering Environmental Justice During the Development of an Action* ("*ADP Interim Process Guide*"), OPEI Regulatory Development Series (July 2010), *available at* http://www.epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-07-2010.pdf .

[433] EPA, *Draft Technical Guidance for Assessing Environmental Justice in Regulatory Analysis ("Draft EJ Technical Guidance")*, Post-Internal Agency Review Draft (Apr. 2013), *available at* http://www.regulations.gov/#!docketDetail;D=EPA-HQ-OA-2013-0320, at v.

[434] RIA at 7-9 to 7-13.

increases," but does not explain what those environmental justice implications are and how it has addressed or mitigated these potential impacts in the proposal. *Id.* at 34,949. EPA must provide a detailed explanation in the final rule.

Second, natural gas-fired EGUs that increase their utilization due to operation at higher capacity factors would operate for more hours in the year, emitting pollutants with localized effects. However, EPA notes that because they emit no Hg, natural gas-fired EGUs would not increase methylmercury concentrations. In addition, these plants would not cause higher peak concentrations of $PM_{2.5}$, NOx or ozone than is already occurring because peak hourly or daily emissions generally would not change, "but increased utilization may make periods of relatively high concentrations more frequent." *Id.* at 34,950. Citing studies by DOE/NETL that provide that natural gas-fired plants have negligible SO_2 and particulate matter emissions, and that their NOx emissions are ten times lower than a subcritical or supercritical coal-fired boiler, EPA concludes that local air quality "is likely to be affected very little." *Id.* EPA, however, has not adequately explained why re-dispatch will not result in higher emissions of criteria air pollutants in the vicinity of gas-fired plants that increase their output.

EPA should prepare an expanded environmental justice analysis of the Clean Power Plan that adequately supports these conclusions and that identifies any specific disproportionate impacts or "EJ concerns" (as defined in the ADP Interim Process Guide). In other words, as the agency's own guidance provides, EPA should assess in detail whether any aspect of the proposed rule (most obviously, the increased utilization of fossil fuel-fired EGUs—both of coal-fired and natural gas-fired plants) would create new disproportionate impacts or exacerbate existing disproportionate impacts on minority or low-income populations, and also, whether any aspect of the proposed rule (for example, increased renewable energy generation) would "[p]resent opportunities to address existing disproportionate impacts on minority, low income, or indigenous populations that are addressable through the action under development."[435] If the proposed rule would result in environmental or socio-economic impacts, or would add to cumulative impacts to minority and low-income populations that already face environmental hazards, EPA should include measures to avoid or mitigate these impacts in the final rule. If, after performing the analysis, EPA concludes that no such impacts would result, the agency should adequately support the basis of its conclusions.[436]

[435] EPA, *ADP Interim Process Guide*, *supra* n. 432, at 6.

[436] EPA's draft *EJ Technical Guidance* provides that EPA's regulatory analyses of a policy aimed at strengthening an environmental standard have often assumed that there would be no environmental justice concerns because the regulation is expected to reduce environmental burdens. This is also the case with the proposed Clean Power Plan. In the guidance, EPA recognizes that "this assumption may lead to erroneous conclusions," and thus recommends preparing a basic analysis that supports conclusions with regard to potential distributional effects, in order to improve the transparency of the rulemaking process and provide the public with more complete information regarding the expected effects of the policy. EPA should (at the very least) follow its own guidance in this respect. EPA, *Draft EJ Technical Guidance*, *supra* at n. 433, at 37.

EPA has done comprehensive environmental justice analyses in the context of other rulemakings in the past. After finalizing the 2008 Definition of Solid Waste ("DSW") rule, EPA committed to conduct an expanded environmental justice analysis in response to stakeholders' concerns about the rule's potential impact on communities. The agency developed a sound methodology to identify potential hazards to communities from the recycling of hazardous secondary materials and the facilities that "may take advantage" of the rule.[437] After mapping these facilities against the demographics of the surrounding communities, EPA determined that certain population groups would be disproportionately affected by the increased risk of adverse impacts, and incorporated means to mitigate these impacts, for example, by closely monitoring the facilities that notify under the rule.[438] EPA should follow its own guidance and draw useful lessons from this precedent in preparing an environmental justice analysis of the Clean Power Plan. Below we suggest a two-phase process for developing such an analysis.

B. It is "Practicable" to Require States to Conduct an Environmental Justice Analysis as a Component of Implementation Plans.

In the proposal, EPA is essentially leaving the decision on how to avoid the creation of environmental justice impacts to the states, but without giving them any guidance on how to do so. The proposal generally provides that a state can take steps to avoid increased utilization of particular EGUs, and thus avoid increased emissions of regulated pollutants with localized environmental effects. To the extent that states take this course of action, EPA concluded that "there would be no new environmental justice concerns in the areas near such EGUs." 79 Fed. Reg. at 34,949.

In acknowledging that some NGCCs may not be equipped with NOx emissions controls such as selective catalytic reduction, EPA concludes that "[d]epending on the specificity of the state CAA section 111(d) plan, the state may be able to predict which EGUs and communities may be in this type of situation and to address any concerns about localized NOx concentrations in the design of the CAA section 111(d) program, or separately from the CAA section 111(d) program but before its implementation." *Id*. EPA also contemplates that any environmental justice impacts that result from the implementation of the emission guideline will be dealt with "ex-post," i.e. after rule making has been completed, because "existing tracking systems" will inform EPA and the states of which EGUs have increased their utilization significantly, to enable them to prioritize efforts in assessing changes in air quality in the vicinity of such EGUs." *Id*. By declining to analyze environmental justice impacts because of uncertainty about the content of state plans, EPA is failing to effectively integrate environmental justice considerations into this rule making, as required in accordance with EO 12898 and pursuant to its own policies and guidelines.

While EO 12898 is addressed directly to the activities and policies of federal agencies, EPA could determine that, in the context of this rule making, it is "practicable" under EO 12898

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[437] EPA*, Plan EJ 2014, supra* at n. 430, at 5.
[438] *Id.*

to require states to conduct an environmental justice analysis as part of the development of their implementation plans. The Clean Power Plan differs from other rules EPA has issued under Section 111 insofar as it does not mandate the installation of specific control technologies to achieve the required emission reductions; rather, states have flexibility to comply with the required state goals through the combination of building blocks that makes the most sense depending on their particular circumstances. This is why EPA cannot at this point predict with certainty which coal-fired and which natural gas-fired plants will increase or decrease their utilization as a result of the implementation of Building Blocks 1 and 2. Therefore, the agency should require states to provide this information as part of the submission of their plans. EPA could also require owners or operators of affected sources to provide necessary information to assist in the development of state plans, as authorized to do so under Section 114 of the Act. 42 U.S.C. §7414(a)(i)(1). The information will enable it to prepare a full-fledged environmental justice analysis as instructed under EO 12898, which the agency should complete before state plans' approval. This requirement would also further EPA's obligation to collect and analyze information on environmental and human health risks borne by populations identified by race, national origin, or income, as mandated under Section 3-302(a) of the Order.

An environmental justice analysis should thus be one of the state plan components, and effective integration of environmental justice concerns should be one of the approvability criteria. To this end, EPA should provide guidance to states on how to prepare this analysis and address these concerns in their plans. We suggest the agency to review its own EJ guidance and the methodology followed in the draft environmental justice analysis to the DSW rule in order to assess what steps of the environmental justice analysis EPA can undertake at this point, and what steps and information it should require states to undertake and provide, as exemplified below.

C. Methodological Considerations

As noted above, in the draft environmental justice analysis of the DSW rule, EPA developed a sound methodology to identify potential hazards to communities from the recycling of hazardous secondary materials. EPA could follow this methodology and its own guidance to define the parameters of the environmental justice analyses that states should prepare as part of their plans, which will inform EPA's own environmental justice analysis to be prepared after plan submission and before approval. The DSW Rule analysis used a 6-step approach, aimed at identifying affected areas and enacting targeted requirements to improve both oversight and accountability for hazardous materials recycling. The six steps, in summary, are the following:[439]

- Step 1: Hazard characterization
- Step 2: Identification of potentially affected communities

[439] EPA, *Environmental Justice Analysis of the Definition of Solid Waste Rule: Draft for Public Comment* (June 30, 2011), available at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-RCRA-2010-0742-0004, at ii.

- Step 3: Demographics of potentially affected communities
- Step 4: Identification of other factors that affect vulnerability in potentially affected communities
- Step 5: Information synthesis: assessment of disproportional impact
- Step 6: Identification of potential preventive and mitigation strategies

EPA, with assistance from the states can and should perform this analysis. We believe that, at this point, EPA can readily perform Step 1 of this methodology. As noted above, in the proposal EPA briefly describes the potential adverse impacts resulting from the application of Building Blocks 1 and 2. These "hazards" should be characterized in greater detail. Using readily available tools (as we describe below), EPA could also perform steps 2 and 3 of the above methodology to construct its guidance to states, but may require them to provide specific information on steps 2 through 4. With the information that states provide in their plans, EPA should complete all steps and develop a full-fledged environmental justice analysis. We explain this in more detail below.

EPA can generally assess the co-pollutant implications of the generic application of Building Blocks 1 and 2 to coal-fired and gas-fired plants that are sited in areas where minority and low income communities reside. Utilizing its unit-level data,[440] EPA can select plants with large nameplate capacity or high capacity factors, or plants in coal- or gas-heavy states, which (hypothetically) may apply Building Blocks 1 and 2, and assess their emissions of CO_2 and criteria air pollutants. EPA should then "map" these facilities against the demographics of the surrounding communities, to find out whether these areas have high percentages of minority or low income populations in proximity (i.e. within a certain radius) from these plants. By way of example, below we provide a list of large (>100 MW) coal-fired plants and their emissions of CO_2 and other co-pollutants, with a brief analysis of environmental justice-related implications that can be made from this data. EPA can obtain information on pollution controls from multiple sources, such as EPA NEEDS, which provides information on SO_2, NOx, PM, and Hg controls, and EIA Form 860, which contains these data in addition to cooling information.

With this information, EPA should determine whether the implementation of Building Blocks 1 and/or 2 would result in disproportionate or adverse impacts on these communities. EO 12898 does not define the term "disproportionate," but other agencies' guidance offers some direction. CEQ's Environmental Justice Guidance under NEPA discusses several factors to consider in determining "disproportionately high and adverse human health effects," including whether the health effects are significant or above generally accepted norms; whether the risk or rate of hazard exposure by a minority or low income population to an environmental hazard is significant and appreciably exceeds or is likely to appreciably exceed the risk or rate to the general population or other appropriate comparison group, and whether health effects occur in

[440] EPA, *Data File: 2012 Unit-Level Data Using the eGRID Methodology*, *supra* n. 166.

a minority or low-income population affected by cumulative or multiple adverse exposures to environmental hazards.[441]

The focus on specific pollutants, however, does not account for cumulative effects, i.e., "the impact[s] on the environment which result from the incremental impact of [an] action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time." 40 C.F.R. § 1508.7[442] As EPA itself notes, minority and low income populations are in many instances affected by multiple environmental hazards, such as industrial facilities, landfills, poor housing, leaking underground tanks, pesticides, and incompatible land uses. Analyzing the effects from these multiple stressors would allow "a more realistic evaluation of a population's risk to pollutants."[443] EPA should draw on its own Framework for Cumulative Risk Assessment and prior cumulative impacts analyses, such as the one prepared in the context of the DSW rule. EPA may also rely on its own guidance for the agency's review of NEPA documents. Although focused on the analysis of projects on ecological resources, the agency could consider the same principles as applied to socioeconomic and human health issues, particularly with respect to the identification of areas cumulatively impacted by a given measure, the delineation of geographic and time boundaries, the identification of all relevant past activities into the affected environment, the utilization of qualitative and quantitative thresholds to determine degradation and cumulative impacts, and the incorporation of mitigation measures to avoid or reduce the severity of those impacts.[444]

EPA has undertaken significant efforts to develop research on cumulative impacts, and should draw from this research in assessing the potential cumulative impacts of the proposed rule. There are many programs and tools to evaluate different components of risk assessments, for example, the Community-Based Technical Support Forum, an EPA workgroup on technical issues that supports community-based risk assessments; EPA's Community Action for a Renewed Environment ("CARE") program, which addresses risk mitigation needs, and the Office of Research and Development's ("ORD") National Exposure Research Laboratory's ("NERL"), which develops and applies exposure models and tools to conduct cumulative exposure assessments, both with respect to health impact and other stressors.[445] NERL is also developing

[441] Council on Environmental Quality, *Environmental Justice: Guidance Under the National Environmental Policy Act* (Dec. 10, 1997), attached as **Ex. 49**, at 26.
[442] EPA, Office of Fed. Activities, *Consideration of Cumulative Impacts In EPA Review of NEPA Documents*, EPA 315-R-99-002 (May 1999), *available at* http://www.epa.gov/compliance/resources/policies/nepa/cumulative.pdf, at 2.
[443] EPA, *ADP Interim Process Guide*, *supra* n. 432, at 8.
[444] EPA, *Consideration of Cumulative Impacts*, *supra* n. 442, at 5-19.
[445] ORD and NERL have also developed models to estimate children's cumulative exposures to chemicals. *See* Zartarian et al., *ORD/NERL's Model to Estimate Aggregate and Cumulative Exposures to Chemicals: SHEDS – Multimedia Version 4* (Jan. 13, 2011), *available at* http://ghhidetroit.cus.wayne.edu/blog/file.axd?file=2011%2F1%2FSHEDS_Presentation_01-13-2011_clearance.pdf.

the Community-Focused Exposure and Risk Screening Tool ("C-FERST"), which will help identify environmental issues and prioritize exposure and risk reduction efforts based on EPA's best available information.[446] Furthermore, EPA's Community Cumulative Assessment Tool ("CCAT"), currently under development, will use information from C-FERST in order to inform the public about the process and complexities of assessing cumulative impacts.[447] To the extent EPA needs more community-level information to prepare a comprehensive "cumulative effects" analysis, it should ask the states to provide it in their own environmental justice analyses in state plans.[448]

If EPA found environmental justice impacts from the general application of Building Blocks 1 and 2 to these plants, the agency should, to the extent practicable, incorporate in the final rule a range of additional measures that states can incorporate in their plans to mitigate these impacts. These measures could be revised when EPA finalizes its environmental justice analysis. For example, EPA could provide that, as part of compliance, states could require affected sources to site additional monitors in locations where minorities and low-income communities reside to address any risks of increased exposure to air pollutants. State plans could also provide for enhanced reporting and record-keeping requirements on these plants.

As for plants that do not have certain types of controls installed (for example, NGCCs without selective catalytic reduction controls, as EPA itself notes), states could require installation of such controls in plants with high capacity factors that are sited in these communities. In planning for retirements or reduced dispatch as part of state plan development, states should be instructed to ensure that the co-pollutant benefits of reduced operations accrue in environmental justice communities. Implementation plans must also contain effective enforcement mechanisms against violators. States would decide on the specific measures to incorporate in their actual plans, but they must ensure that these requirements effectively address environmental justice concerns in order for EPA to approve them. The environmental justice analysis of the DSW rule provides useful lessons on how EPA has effectively integrated environmental justice considerations in rule making.

In the proposed DSW rule, for example, EPA acknowledged that the destination of the waste generated from the rule was not random; rather, some communities would be more affected than others. The rule's implementation would have resulted in a concentration of hazardous waste recycling facilities near low income communities and communities of color, increasing adverse public health conditions to these vulnerable communities. EPA's 2010 re-

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[446] Zartarian et al., *The EPA's Human Exposure Research Program for Assessing Cumulative Risk in Communities*, J, of Exposure Sci. and Envtl. Epidemiology (Apr. 15, 2009), attached as **Ex. 50**, at 352-355.
[447] EPA, *Plan EJ 2014, Progress Report* (Feb. 2014), *available at* http://www.epa.gov/environmentaljustice/resources/policy/plan-ej-2014/plan-ej-progress-report-2014.pdf, at 23.
[448] In a separate rulemaking, EPA should issue a cumulative impacts standard that fully recognizes the existence of these effects on minority and low income communities, providing guidance to states, or any other obligated entity under its rules, to identify and address cumulative impacts in all their programs, policies, and activities.

examination of the 2008 DSW rule identified areas in the existing regulations that could be improved to better protect these communities by ensuring better management of hazardous waste, since the 2008 rule had scaled back federal oversight of management of the waste. EPA effectively integrated environmental justice concerns in the regulations in various ways in the new proposed DSW rule. For example, the 2010 proposal required heightened storage and record keeping requirements compared to the 2008 proposal. Companies that sent their hazardous materials offsite for recycling would have to abide by tailored storage standards, and would be required to send their materials to a permitted hazardous waste recycling facility. The rule also required all forms of hazardous waste recycling to meet requirements designed to ensure materials are legitimately recycled and not being disposed of illegally. EPA established these requirements by assessing multiple scenarios in order to try to reflect how different types of hazardous waste would be managed, based on its interim guidance on how to incorporate environmental justice, and making sure there was opportunity for public involvement.

The ADP Interim Process Guide provides that an environmental justice analysis includes not only the consideration of burdens to minorities and low-income populations, but also the distribution of the positive environmental and health consequences of the agency's actions.[449] EPA has already quantified the co-benefits of the Clean Power Plan in terms of emissions reductions from criteria and hazardous air pollutants, but has also acknowledged that its benefit-per-ton estimates "may not reflect the local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location.[450] Independent research has confirmed that carbon pollution standards on existing power plants that incorporate flexible compliance options (including, for example, demand-side energy efficiency) can result in great co-benefits in terms avoided premature deaths, hospital admissions, and heart attacks. This research has assessed the geographic distribution of those co-benefits, with all lower 48 states receiving some benefit.[451] EPA should assess the geographic distribution of the co-benefits of the rule, and when feasible, information on these benefits should be disaggregated by race, ethnicity, and income,[452] in order for EPA to assess the distribution of benefits of the proposed rule on minority and low income populations.

In assessing all the potential impacts and benefits, EPA could provide a qualitative assessment as part of its guidance in the final rule, and require states to provide a quantitative assessment of these impacts in connection with the compliance measures included in their plans. As EPA details in its draft EJ Technical Guidance, a quantitative assessment would allow EPA to more rigorously assess the manner in which emissions and health effects will be distributed among minority and low income groups during implementation.[453] Such an

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[449] EPA, *ADP Interim Process Guide*, *supra* n. 432, at 3.
[450] RIA at ES-16.
[451] Schwartz et al., *Health Co-Benefits of Carbon Standards for Existing Power Plants, Part 2 of the Co-Benefits of Carbon Standards Study*, Harvard School of Public Health/Syracuse University/Boston University (Sept. 30, 2014), attached as **Ex. 51**, at 3.
[452] *Draft EJ Technical Guidance*, *supra* n. 433 at 3.
[453] *Id*. at 37.

assessment is feasible if each state provides specific environmental justice-related information associated to its selected compliance pathway.

1. Sample Environmental Justice Analysis of Coal Plants

In 2012, the National Association for the Advancement of Colored People ("NAACP"), in conjunction with the Little Village Environmental Justice Organization and the Indigenous Environmental Network, analyzed criteria air pollutant emissions from coal-fired plants in conjunction with demographic factors, concluding that a number of coal plants in the United States had "a disproportionately large and destructive effect on the public's health, especially on the health of low-income people and people of color,"[454] who are more likely to be disproportionately affected by climate change. NAACP's "Coal Blooded" report gave each individual plant a score based on five different factors, including SO_2 emissions, NOx emissions, the total population living within 3 miles of the plant, the median income, and the percentage of people of color among the total population living within 3 miles of the plant.[455] NAACP's "Environmental Justice Performance" ("EJP") score was calculated based on the data collected, using both an exposure score and a demographic score multiplied to obtain a cumulative score.

In assembling the list of coal-fired power plants used in the study, NAACP used EIA's 2008 "Existing Electric Generating Units in the United States" database and filtered it out to obtain 601 coal-fired (or partially coal-fired) power plants. Using only plants that have a capacity greater than 100 MW (as well as leaving out plants that had, as of July 1, 2011, been fully decommissioned, had converted to other fuel stocks, or were fully non-operational from 2007 to 2010), NAACP obtained a list of 378 coal-fired power plants for analysis.[456] Demographic data was based on the 2000 census report.

In this analysis, NAACP found that 6 million Americans living near coal plants had an average income of $18,400, in comparison to the $21,857 average income nationwide, and of those 6 million Americans, 39 percent were people of color.[457] While the 75 plants that received a grade of "F" only produced 8 percent of the total electricity, they accounted for 14 percent of overall SO_2 emissions and 13 percent of NOx emissions.[458] The average per capita income of the people living within 3 miles of these 75 plants (roughly 4 million people) was $17,500, and nearly 53 percent were people of color.[459]

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[454] NAACP, *Coal Blooded: Putting Profits Before People* (Nov. 2012), attached as **Ex. 52**, at 9.
[455] *Id*. at 33.
[456] *Id.* at 86.
[457] *Id.* at 15.
[458] *Id.* at 27.
[459] *Id.*

Sierra Club has expanded this analysis, incorporating the data from NAACP's Coal Blooded report and analyzing emissions from a list of 384[460] coal-fired power plants. Using the data from the NAACP's report as a starting point, we have then included generation data from EIA and emissions data from EPA for both years 2012 and 2013, as well as CO_2 emissions for all years under analysis. Demographics information in this sample still corresponds to the 2000 census, rather than the newer 2010 census data. Since the 2000 census, population has increased approximately 27.3 million.[461] Over the last decade, however, there has been a slower increase in population growth (approximately 3.5 percent), with much of that increase coming from the South and Western regions.[462] Emissions information in this sample does correspond to the most recent data from EIA. While demographic data is not the most recent, we hope this example provides EPA with a methodology of the initial steps of an environmental justice analysis (i.e. identification of hazards, mapped against demographic information). EPA should perform this analysis both for coal-fired and gas-fired plants. As we discuss below, EPA can draw demographic data from a variety of tools.

A partial version of our analysis (depicting only 2013 emissions) is shown below. The full analysis is attached as Appendix 5. The figure below shows 50 plants in our study with the lowest per capita average income within three miles of the plant.

[460] The NAACP report lists 378 plants in its analysis. However, some of these plants are actually two separate plants as identified in EIA, so we have broken out these groupings in this dataset for more clarity.
[461] *Id.* at 1.
[462] U.S. Census Bureau, *Population Distribution and Change: 2000 to 2010*, 2010 Census Briefs (March 2011), *available at* http://www.census.gov/prod/cen2010/briefs/c2010br-01.pdf, at 1.

Table 15- SO_2, NOx, and CO_2 Emissions, and Demographics of Large Coal-Fired Plants in the U.S.[463]

State	Plant Name	2013 SO_2 Emissions (tons)	2013 NO_x Emissions (tons)	2013 CO_2 Emissions (metric tons)	Pop. Within 3 Miles	3-Mile Avg. Income	% of State Avg. Income	3-Mile POC Pop.	Overall Rank	Grade
NM	Escalante	951	3036	1,631,803	372	6701	38.8%	90.2%	18	F
NM	Four Corners	10706	35434	11,704,484	488	6762	39.2%	94.9%	11	F
TX	Harrington	14309	4890	5,949,094	4724	9134	46.6%	46.3%	39	F
TN	Allen	9992	1937	4,295,754	2589	9412	48.5%	99.2%	16	F
SC	Williams	909	1485	2,786,621	4496	9653	51.4%	32.6%	60	F
AZ	H Wilson Sundt Generating Station	1372	1272	588,943	56609	10258	50.6%	74.7%	13	F
SC	Cross	6687	4513	12,349,148	1068	10626	56.5%	76.3%	29	F
OH	Lake Shore	1058	308	261,789	103333	10866	51.7%	90.6%	6	F
IL	Crawford	0	0	0	373690	11097	48.0%	83.9%	1	F
LA	Rodemacher	11320	4622	7,628,231	1237	11154	66.0%	66.7%	58	F
NC	Edgecombe Genco LLC	100	873	326,003	4370	11735	57.8%	67.2%	31	F
NC	W H Weatherspoon	5	13	1,609	10450	11867	58.4%	50.3%	40	F
NM	San Juan	6055	16817	11,301,567	937	11982	69.4%	74.9%	45	F
SC	Canadys Steam	7789	1279	733,737	943	12127	64.5%	45.2%	91	D-
SC	Wateree	5548	1472	2,791,544	367	12422	66.1%	82.8%	38	F
AZ	Coronado	843	9952	6,431,282	313	12470	61.5%	33.4%	117	D
PA	Colver Power Project	2756	887	0	1980	12523	60.0%	2.1%	187	C
SC	Urquhart	5	201	564,793	7464	12623	67.2%	77.2%	30	F
OH	Killen Station	7885	6401	3,471,845	441	12788	60.9%	2.9%	216	C+

[463] The data in this table derive from AMPD data, NAACP's *Coal-Blooded* report, *supra* n. 454, and Sierra Club's internal analysis.

WI	Valley	3468	1041	870,418	209421	12852	60.4%	66.0%	4	F
IN	R Gallagher	2495	1200	620,541	60333	12868	63.1%	60.8%	8	F
VA	Clover	2262	8417	5,859,241	837	12916	53.9%	48.4%	76	D-
KY	Green River	19998	2272	977,874	2462	12921	71.4%	9.8%	179	C
CO	Pawnee	12467	3740	3,296,108	1200	12964	53.9%	25.9%	101	D
MD	AES Warrior Run Cogeneration Facility	1236	560	1,474,035	10914	12982	50.7%	10.7%	89	D-
MI	River Rouge	9214	3008	2,182,711	68262	13037	58.8%	65.3%	7	F
OH	J M Stuart	11542	8674	12,564,882	3781	13094	62.3%	13.7%	80	D-
AZ	Cholla	5065	8649	7,478,704	1076	13096	64.6%	27.3%	120	D
FL	Indiantown Cogeneration LP	1264	1124	732,998	3403	13107	60.8%	68.2%	34	F
AZ	Springerville	7939	7304	10,802,018	142	13255	65.4%	31.0%	146	D+
IL	Baldwin Energy Complex	4803	4960	12,162,722	4121	13419	58.1%	51.7%	44	F
KY	Paradise	21524	7739	12,008,055	593	13427	74.2%	6.6%	214	C+
VA	Clinch River	3994	1020	927,182	1271	13472	56.2%	1.8%	172	C-
OK	Sooner	14380	8222	5,812,930	130	13555	76.8%	44.8%	139	D+
AL	Gadsden	1526	414	192,348	24955	13600	74.8%	49.9%	37	F
OK	AES Shady Point LLC				2422	13636	77.3%	19.0%	141	D+
MS	Red Hills Generating Facility	3159	2019	3,586,888	830	13665	86.2%	26.1%	233	INC
CO	Cherokee	2584	5172	3,019,206	61559	13682	56.9%	64.4%	9	F
LA	Dolet Hills	14612	3167	3,350,443	412	13767	81.4%	50.3%	124	D
PA	Conemaugh	6408	18171	10,511,278	2729	13800	66.1%	1.3%	165	C-
AL	Greene County	32833	4878	2,470,243	480	13821	76.0%	78.8%	59	F

UT	Huntington	2409	7482	6,220,976	249	13855	76.2%	12.5%	253	INC
NE	North Omaha	12237	6258	3,592,614	43133	13858	70.7%	56.7%	17	F
OK	Hugo	10878	3348	3,360,726	712	13980	79.2%	17.7%	229	INC
OR	Boardman	13967	4038	3,601,219	233	13982	66.8%	48.6%	99	D-
TX	Oklaunion	3809	7266	4,099,987	193	14004	71.4%	32.8%	155	C-
UT	Utah Smelter				752	14013	77.1%	22.8%	195	C
OK	Chouteau				2277	14026	79.5%	26.2%	128	D+

In analyzing the data, one can make the following conclusions: First, 197 of the 384 coal plants identified in the NAACP report fall under the low income threshold of $17,505 per capita, as defined by the U.S. Department of Education.[464] From these 197 plants, an average of 51.6 percent of the people (then) living within 3 miles of the individual plants are people of color. The average per capita income of the people living within 3 miles of these 197 plants (approximately 2.94 million people) was $14,532.84, compared to an average of $22,158.91 per capita income of the people living within 3 miles of the other 187 plants (approximately 3 million people). Out of all of the 197 plants that fall below the low income threshold, the five plants with the lowest per capita income within the 3-miles area around the individual plants include Plants Escalante and Four Corners in New Mexico, Plant Harrington in Texas, Allen Plant in Tennessee, and Plant Williams in South Carolina, all of which were surrounded by communities with income of less than $10,000 per capita.

Across the board, these 197 plants produced more CO_2, SO_2, and NOx emissions overall in both 2012 and 2013 compared to the 187 other plants in the study that are above the low income threshold. Specifically, these plants produced on average 33 percent more NOx emissions, 21 percent more SO_2 emissions, and 11 percent more CO_2 emissions than the other 187 plants in 2013, and 24 percent more NOx emissions, 11 percent more SO_2 emissions, and 9 percent more CO_2 emissions in 2012. This means that these 197 plants we identified as under the low income threshold would be causing adverse impacts in low income communities in comparison with the rest of the plants identified in the study.

The graphs below show that, based on all of the 384 plants in the study, as average income increases, emissions (of NOx and CO_2, respectively) decrease, as seen from the negative slope of the best fit lines. Conversely, emissions are higher in lower income areas.

[464] U.S. Dep't of Education, *Federal TRIO Programs Current-Year Low-Income Levels*, http://www2.ed.gov/about/offices/list/ope/trio/incomelevels.html (last visited Nov. 24, 2014).

Fig. 27- 2013 NOx Emissions (tons) vs. Average Income

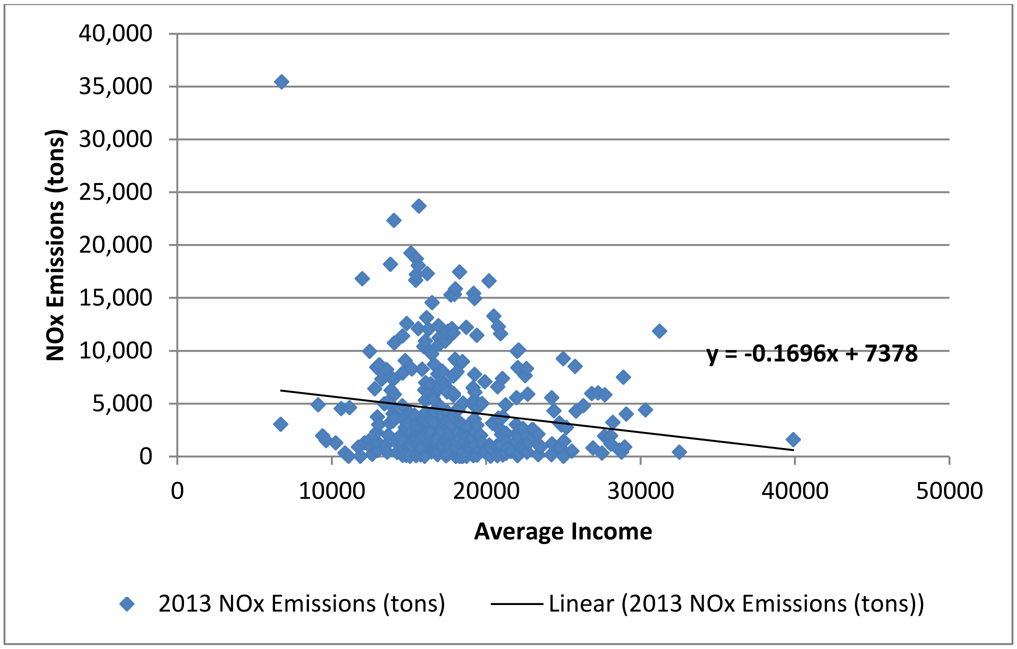
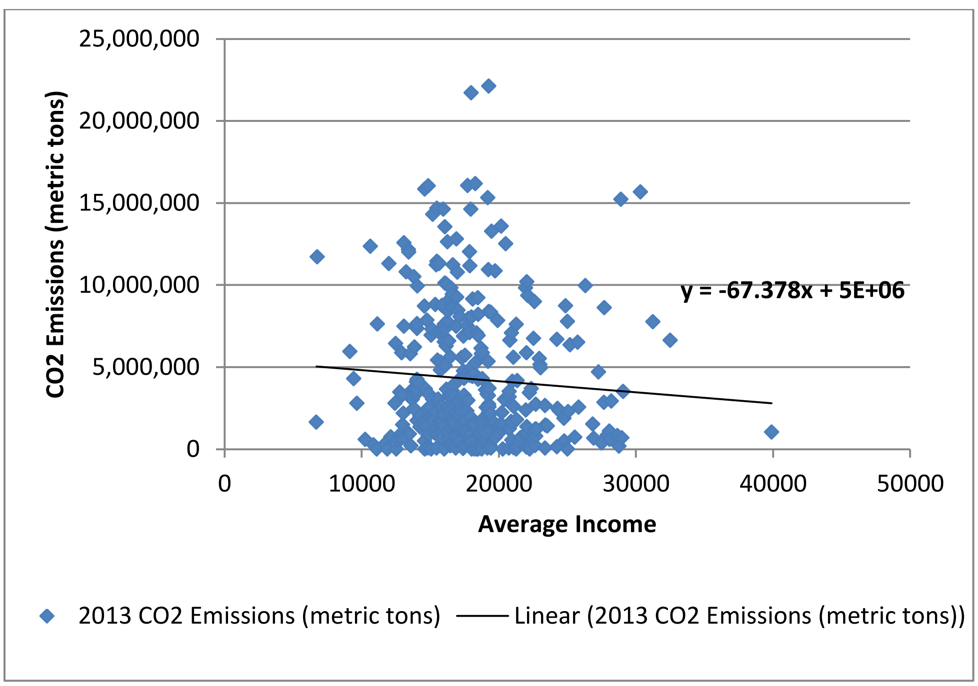
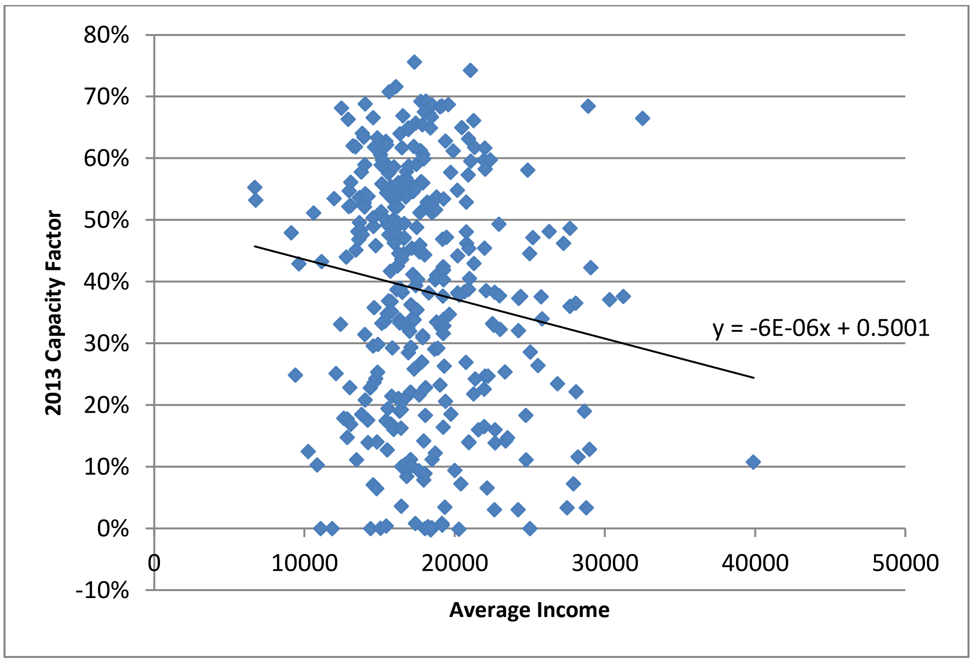


Fig. 28- 2013 CO2 Emissions (metric tons) vs. Average Income



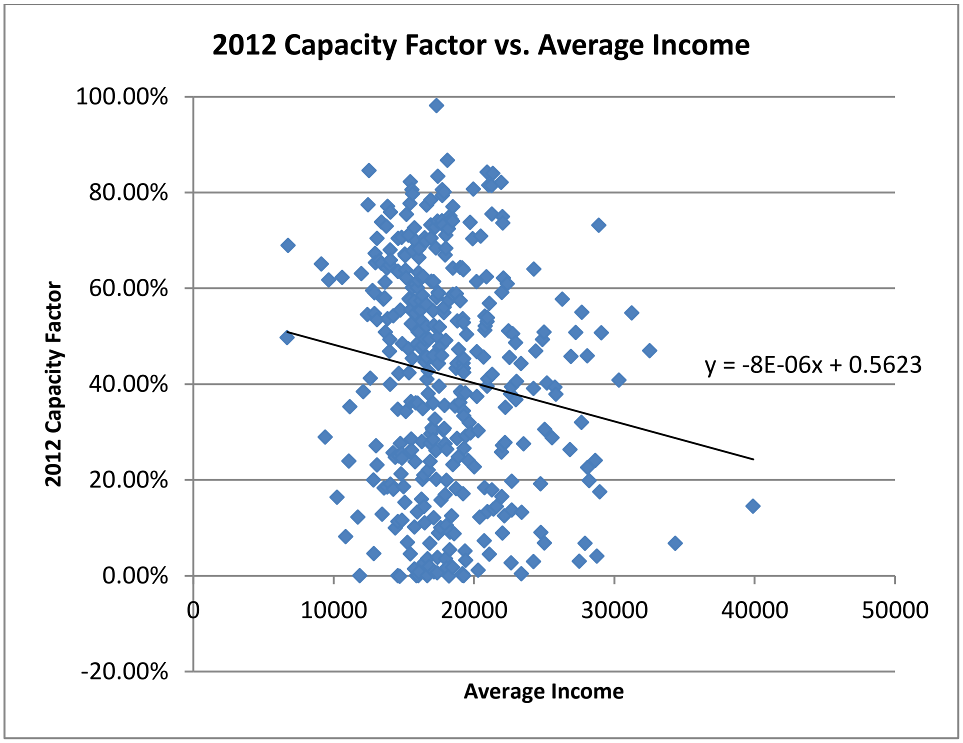
In addition, the average capacity factor for the 197 plants that fall below the low income threshold is higher overall for both years 2012 and 2013 than the other 187 plants in the study. Of the plants in the study, the average capacity factor in 2012 was 42 percent, and in 2013 it was 39 percent.[465] The graphs below show that, for all of the 384 plants in the study, the capacity factor decreases as the average income increases. This lower capacity factor correlates to less operation, and thus less pollution in the areas that have a higher average income. On the other hand, areas that have a lower average income see, on average, a higher capacity factor, indicating that those plants are being run more frequently, and thus polluting more.

Fig. 29- 2013 Capacity Factor vs. Average Income



465 The 2013 capacity factor might change slightly since not all generation data has been reported yet.

Fig. 30- 2012 Capacity Factor vs. Average Income



Obtaining emissions information and mapping them against demographic criteria is a good first step to identify highly polluting plants and potential adverse burdens placed on minorities and low income communities. This type of finding would aid EPA and the states in deciding how to properly integrate environmental justice considerations in this rule making, incorporating targeted measures so that emissions reductions actually occur in environmental justice communities.

2. Data Gathering: Available Tools

In commencing an environmental justice analysis, EPA could utilize a variety of readily available tools to collect environmental and demographic information. Below we highlight some of these tools, along with their strengths and weaknesses.

a. EJView

One tool that could aid EPA in determining which communities would be disproportionately impacted by the Clean Power Plan is EPA's own mapping tool "EJView" (formerly known as the Environmental Justice Geographic Assessment Tool). The tool allows users to create maps and generate detailed reports based on the geographic areas and data sets they choose. The EJView homepage describes multiple factors that have the potential to affect the selected communities, including demographics, health, environmental, and facility-level data (such as air emissions data from The Air Facility System and water discharges tracked through EPA's permit compliance system).[466] This tool would be particularly useful to gather information on cumulative impacts. In order to generate a cumulative health impacts assessment of the Clean Power Plan, for example, EPA can obtain data from the tool by selecting the specific map contents and generating a detailed depiction of individual communities. The tool incorporates the following data: Hazardous Waste ("RCRAInfo"), Toxics Release Inventory ("TRI"), Superfund ("CERCLIS"), Brownfields ("ACRES"), nonattainment areas, demographic data based on the 2010 US Census Population and Housing 100 percent count database, health information from the National-Scale Air Toxics Assessment ("NATA"), and other monitoring data, thus creating a more aggregated database incorporating multiple factors.[467]

b. EJSEAT

"EJ SEAT", a tool designed by EPA's Office of Enforcement and Compliance Assurance, assigns scores to every census tract in the country (approximately 65,000 tracts) by using an index compiled from 18 indicators which are grouped into 4 different categories (environmental indicators, human health/health indicators, compliance indicators, and social/demographic indicators).[468] EPA uses data available nationwide at the census tract level, which must come from federally recognized sources. Environmental indicators derive from information from the NATA and the Risk Screening Environmental Indicators ("RSEI") records, and are therefore largely air-focused. The information obtained in the dataset is normalized prior to combining the indicators, done by setting the lowest value of the indicator to zero and the highest to 100. This process is conducted on a state-by-state basis rather than for the United States as a whole. As defined by EPA's Office of Enforcement and Compliance Assurance, the top-scoring 20 percent of the census tracts in each state could be potential environmental justice areas that are facing disproportionate impacts.

Some of the strengths of the tool are that it is a nationally consistent screening tool that follows a systematic approach, and it combines a wider range of data than EPA traditionally uses for environmental justice analyses.[469] We believe that EJ SEAT could be used to identify environmental justice communities where targeted emissions reductions under the Clean Power Plan will be needed. And, in particular, during compliance, this tool could also be helpful to evaluate whether or not the Clean Power Plan has been effective in improving environmental justice in those particular areas. For example, the tool can be used to find out whether pollution prevention efforts have focused on environmental justice areas, and whether sufficient grants have been provided to these communities.

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[466] EPA, *EJView*, http://epamap14.epa.gov/ejmap/entry.html (last visited Nov. 24, 2014).
[467] EPA, *EJView*, *Description of Map Features*, http://epamap14.epa.gov/ejmap/help/help.html?tab=3 (last visited Nov. 24, 2014).
[468] Schulman & Harris, EPA, *EJSEAT: A Screening Tool for EJ Concerns, Strengthening Environmental Justice Research and Decision Making Symposium*, (Mar. 18, 2010), *available at* http://www.epa.gov/ncer/events/calendar/2010/mar17/presentations/andrew_schulman.pdf, at 4-5.
[469] *Id*.

While the tool has clear strengths, it also has weaknesses that should be acknowledged, so that the agency supplements these gaps with other tools and information from other sources. One of the issues with the data collection methods is that the human health category is hard to quantify because only a few indicators are "available at the census tract level across the nation in a way that is accessible due to privacy issues."[470] In addition, this tool does not capture communities smaller than 4,000 people due to census tracts, so that it may not capture some tribal communities.[471] Finally, in the compliance indicator there is no distinction between serious violations significantly impairing air or groundwater, and violations with no material environmental impact. In addition, since state enforcement differs from state to state, what might be cited as a violation somewhere might be ignored elsewhere.

c. CalEnviro Screen 2.0

The California Communities Environmental Health Screening Tool ("CalEnviroScreen 2.0") is a tool used to identify communities that are disproportionately burdened by different sources of pollution, and EPA could maximize the use of this tool for an environmental justice analysis of the Clean Power Plan in California. The specifics of this tool could also provide useful lessons to other states in gathering and assessing the information they would be required to submit as part of their plans.

CalEnviroScreen 2.0 measures adverse environmental impacts by using 19 different indicators including pollution burden, socioeconomic vulnerabilities, public health risk factors, among other indicators, which can be used to assess areas most heavily impacted by pollution. The demographic data is derived from roughly 8,000 census tracts (using the 2010 census) throughout the state and then assembled into an interactive map.[472] The tool compiles all of these different indicators when evaluating a particular location, and ranks zip codes statewide for comparison. By dividing regions by census tracts rather than just the roughly 1,800 zip codes in the state, CalEnviroScreen 2.0 has the ability to provide an impartial accounting of circumstances in areas that potentially have a smaller number of residents, thus making it possible to obtain a more in-depth analysis. Using these indicators, the tool has the ability to take into account socioeconomic characteristics, health statistics, and environmental exposure to give a much more precise indication of the environmental risks faced by these vulnerable populations. The tool can thus provide guidance to state and local policymakers on where to best direct their resources and programs.

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[470] Nat'l Envt'l Justice Advisory Council ("NEJAC"), Meeting Transcript (Sep't 19, 2007), *available at* http://www.epa.gov/compliance/ej/resources/publications/nejac/nejacmtg/nejac-meet-trans-091907.pdf.

[471] Note, however, that NEJAC's evaluation of the tool raised doubts that it can ultimately meet the needs of both the agency and the broader environmental justice community, so that it is important to be aware of its shortcomings. *Id*.

[472] California Envt'l Protection Agency, *Designation of Disadvantaged Communities Pursuant to Senate Bill 535* (Oct. 2014), attached as **Ex. 53**, at 13.

CalEnviroScreen 2.0, unlike EJSEAT, is available to the public, whereas EJSEAT is limited to internal use by the EPA. CalEnviroScreen 2.0's guidance document notes that the tool should mostly be used in planning for compliance and use by local and regional governments.[473] Furthermore, the tool will be used to help implement SB 535 which, as we explain below, would distribute funds generated by California's AB32 allowance auctions, allocating 25 percent of the available funds to projects that provide benefits to disadvantaged communities, with no less than 10 percent of the proceeds being used to directly benefit disadvantaged communities.[474] Because the tool helps to prioritize abatement projects and resources for clean-up, the California Environmental Protection Agency ("CalEPA") additionally plans to use the resource to aid in administering its Environmental Justice Small Grant Program.[475]

d. EJ Screen

EJScreen, a screening and mapping tool used by EPA, will be available to the public in late 2014. EJScreen compiles "EJ indexes" using demographic information (at the census tract level and group block level) and environmental indicators in order to identify specific communities that may be disproportionately burdened by a given environmental harm.[476] There are 12 different environmental indicators and seven demographic indicators.[477] Like EJSEAT, EJScreen will be a nationally consistent environmental justice screening tool. EJScreen can be used to identify where specific environmental risks occur in certain communities. A report generates all 12 environmental indicators in one area, while a map provides one environmental indicator at a time over a wider area. EPA could use this tool to identify disproportionately burdened communities using the different environmental indicators.

D. EPA Must Continue to Ensure Meaningful Involvement of Minorities and Low Income Communities in this Rule Making.

Executive Order 12898 requires federal agencies to conduct their "programs, policies, and activities that substantially affect human health or the environment, in a manner that ensures that such programs, policies, and activities do not have the effect of excluding persons (including populations) from participation in, denying persons (including populations) the benefits of, or subjecting persons (including populations) to discrimination under, such programs, policies, and activities, because of their race, color, or national origin." § 1-101. In

[473] California Envt'l Protection Agency*, California Communities Environmental Health Screening Tool, Version 2.0, Guidance and Screening Tool* (Oct. 2014), attached as **Ex. 54**, at 5.
[474] *See* Cal. Health & Safety Code §§ 39710-39723 (codifying SB-535 California Global Warming Solutions Act of 2006: Greenhouse Gas Reduction Fund).
[475] California Envt'l Protection Agency, *supra* n. 473, at 5.
[476] EPA, *EJSCREEN Fact Sheet*, available at http://icma.org/en/icma/knowledge_network/documents/kn/Document/306760/EPA_EJSCREEN_Fact_Sheet, at 1.
[477] EPA, *EJSCREEN: Environmental Justice Screening Tool*, available at http://www.epa.gov/air/caaac/pdfs/ejscreen_102914.pdf, at 12.

addition, the Order seeks to promote public participation by requiring federal agencies to "ensure that public documents, notices, and hearings relating to human health or the environment are concise, understandable, and readily accessible to the public," and encouraging them to "translate crucial public documents, notices, and hearings relating to human health or the environment for limited English speaking populations." § 5-5.

In furtherance of these requirements, EPA's guidance provides that minority and low income communities must have an adequate opportunity to participate in decisions about a proposed activity that will affect their health or their environment, and their concerns must be considered in the agency's decision-making process.[478] The inability of these communities to participate in this process constitutes an "EJ concern" that may itself contribute to disproportionate impacts. To avoid such impacts, EPA must engage these communities early in the process through targeted outreach efforts, in a manner that overcomes any lack of trust, as well as any language, communication, and information barriers.[479]

In the context of this rule making, EPA has hosted webinars, conference calls, and workshops for environmental justice communities on August 27, September 9, and October 30, 2014. EPA indicates that it "has taken all comments and suggestions [from these communities] into consideration in the design of the emission guidelines." 79 Fed. Reg. at 34,950. We ask EPA to describe in the final rule what these (and any other suggestions submitted during the comment period) are and how they have been addressed. We also commend EPA for arranging these targeted sessions, and urge the agency to continue to provide these communities with opportunities for meaningful involvement in the rule making process, and to actively seek their input in the development of a comprehensive environmental justice analysis of the Clean Power Plan.

E. State Plans Must Ensure Compliance with Title VI of the Civil Rights Act.

Title VI of the Civil Rights Act ("Title VI"), Section 601, provides that "[n]o person in the United States shall, on the ground of race, color, or national origin, be excluded from participation in, be denied the benefits of, or be subjected to discrimination under any program or activity receiving Federal financial assistance." 42 U.S.C. § 2000d. Title VI "reaches *unintentional, disparate-impact* discrimination as well as deliberate racial discrimination." *Guardians Ass'n v. Civil Service Com'n of City of New York*, 103 S.Ct. 3221, 3227 (1983) (emphasis added). Section 602 of the statute requires every federal agency and department empowered to grant financial assistance to issue regulations to effectuate the provisions of Section 601. *Id.* § 2000d-1.

In addition, Executive Order 12250, *Leadership and Coordination of Nondiscrimination Laws*, directs federal agencies to issue appropriate Title VI implementing directives, either in the form of policy guidance or regulations consistent with the requirements prescribed by the

[478] EPA, *ADP Interim Process Guide*, *supra* n. 432, at 3.
[479] *Id*. at 9.

Department of Justice's Assistant Attorney General for Civil Rights. Exec. Order No. 12250, § 1-402. The presidential memorandum accompanying EO 12898 also requires federal agencies providing funding to programs or activities that affect public health or the environment to comply with Title VI of the Civil Rights Act.[480]

EPA's implementing regulations forbid recipients[481] of federal funds from using "criteria or methods of administering [their] program[s] or activit[ies] which have the effect of subjecting individuals to discrimination because of their race, color, national origin, or sex." 40 C.F.R. § 7.35(b). These regulations also preclude a recipient of federal funds from choosing a site or location for a facility that would result in discriminatory effects. 40 CFR § 7.35(c). Other EPA's regulations mandate that state agencies that receive federal funds maintain Title VI compliance programs for themselves and other recipients that obtain federal assistance through such programs. 28 C.F.R. § 42.410.

State agencies implementing the Clean Power Plan (i.e., state air or environmental protection agencies) who receive funding from EPA are responsible for ensuring that funded activities (for example, permitting processes) that become part of compliance plans under the Clean Power Plan conform to Title VI requirements. If any program or measure in a state plan that was funded by EPA resulted in discrimination on the basis of race, color, or national origin, those agencies would be in violation of Title VI, and aggrieved persons would be entitled to file an administrative complaint with EPA. 40 C.F.R. § 7.120. With respect to the administrative complaint procedure, we reiterate EPA's need to make modifications to the complaint investigation and resolution process in a manner that ensures meaningful participation of environmental justice communities and effective enforcement of Title VI complaints.[482]

In addition, if compliance cannot be achieved voluntarily, the regulations authorize EPA to deny, suspend or terminate funding to the particular program under which the agency has found discrimination. EPA may also refer the matter to the Department of Justice to get

[480] *Memorandum from President Clinton Executive Order on Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations* (Feb. 11, 1994)*, available at* http://www.epa.gov/swerffrr/documents/executive_order_12898.htm.

[481] The regulations define "recipient" as "any State or its political subdivision, any instrumentality of a State or its political subdivision, any public or private agency, institution, organization, or other entity, or any person to which Federal financial assistance is extended directly or through another recipient, including any successor, assignee, or transferee of a recipient, but excluding the ultimate beneficiary of the assistance." 40 C.F.R. § 7.25.

[482] Letter from Center on Race, Poverty & the Environment, The City Project, Conservation Law Foundation, Earthjustice, Environmental Justice League of Rhode Island, Humansynergyworks.org, New Mexico Environmental Law Center, NRDC, Sierra Club, West End Revitalization Association, Inc., Marc Brenman, and Patrice Lumumba Simms to EPA Administrator Gina McCarthy (Nov. 5, 2013), attached as **Ex. 55**.

compliance. 40 C.F.R. § 7.130.[483] EPA should make use of this authority if any program in a state plan funded by EPA resulted in a Title VI violation.

Meaningful public involvement is also necessary to ensure recipients' compliance with Title VI. As EPA notes in its Title VI's "Recipient Guidance," early and inclusive public involvement of environmental justice communities in the permitting process is critical to ensure that the use of federal funds does not discriminate against these communities on the basis of race, color, or national origin.[484] In this guidance, EPA has suggested specific public involvement approaches in the permitting process that could also apply to the process of developing and implementing state plans under the Clean Power Plan.

First, funding recipients could prepare a "public involvement plan" with the participation of environmental justice communities, to ensure that state plan development efforts address the issues that are important to these communities.[485] Second, recipients could equip communities with appropriate tools such as information materials, training sessions (including in other languages, if there are non-English speaking communities), and grants to ensure their active and effective participation in the plan development process.[486]

Finally, during plan implementation, funding recipients should work to ensure that local authorities integrate environmental justice concerns early in the process, which will require acknowledging communities' concerns about existing facilities near residential areas; working with the relevant authorities to ensure that data on demographics and location of existing facilities in communities are considered before making any siting decisions; and working with those authorities to identify locations for new facilities that avoid net increases in pollution in communities with disproportionately high exposure or that already host a number of facilities."[487]

As we discussed above, effective integration of environmental justice concerns should be one of the approvability criteria for state plans. This includes requirements on recipients of EPA's funding; i.e., state implementing agencies, to comply with non-discrimination obligations under Title VI and EPA's implementing regulations. We urge the agency to address these obligations of recipient agencies in the final rule, including options for meaningful public

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[483] *Draft Title VI Guidance for EPA Assistance Recipients Administering Environmental Permitting Programs (Draft Recipient Guidance) and Draft Revised Guidance for Investigating Title VI Administrative Complaints Challenging Permits (Draft Revised Investigation Guidance)*, 65 Fed. Reg. 39,650, 39,696-97 (June 27, 2000).
[484] *Title VI Public Involvement Guidance for EPA Assistance Recipients Administering Environmental Permitting Programs (Recipient Guidance)*, 71 Fed. Reg. 14,207, 14,210 (Mar. 21, 2006).
[485] *Id.* at 14,211.
[486] *Id.* at 14,213.
[487] *Id.* at 14,214-15. This would be the case, for example, if EPA allowed new gas-fired power plants as a compliance measure under state plans. However, we believe that EPA should not allow new gas for compliance, as we discuss in Section XIII.B.

involvement, so that states construct their implementation plans in a manner that ensures compliance with Title VI.

F. EPA Must Clarify that State Plans that Allow Uncontrolled or Poorly Controlled Co-Pollutant Emissions from Individual Sources Are Not Permissible As Section 111(d) Emission Guidelines for Pollutants with Localized Health and Environmental Impacts.

EPA needs to make clear that emission standards that allow uncontrolled or poorly controlled emissions from individual sources are not permissible as Section 111(d) emission guidelines for pollutants with localized health and environmental impacts.

Under the Clean Power Plan a state might choose to adopt building block measures that have the effect of reducing CO_2 emissions from some EGUs while allowing emissions from others to increase. Although such approaches have advantages in controlling well-mixed pollutants like CO_2 that do not present localized health and environmental threats, they would raise serious concerns if applied to pollutants that do present such threats. Applying similar approaches to Section 111(d) rules for air toxics, criteria pollutants, and other pollutants with localized impacts (collectively, "hotspot" pollutants) would create significant risks to people living near the emitting sources and to ecosystems near such sources. These risks are of particular concern to people in communities that are disproportionately impacted by emissions from power plants and industrial sources.

Accordingly, EPA needs to make clear that any flexible approaches it has proposed under the Clean Power Plan will not apply, and are not transferrable to, emissions of hotspot pollutants from power plants and other sources that are, or may be subject to rules under Section 111(d). According to EPA itself, it is significant that CO_2 is a global pollutant and therefore the location of the emissions (and emission reductions) does not affect the impact on climate change of an amount generated at any given source in any one location.[488] The fact that CO_2 becomes well-mixed in the air "means that CO_2 emissions may be reduced anywhere within the electricity grid and still achieve the intended climate benefits. This allows EPA to determine that a system is the 'best' based on the total emission reductions the system would achieve rather than basing the determination on the emissions reductions achieved at each individual affected source."[489] The same is plainly not true for hotspot pollutants, however, where the location of emissions (and emission reductions) do matter. For such pollutants, EPA would not be able to determine that a system is "best" if it allowed an individual source to emit at uncontrolled or poorly controlled levels, or to rely on reductions at other sources in lieu of reducing its own emissions.

That Section 111(d) rules need to protect against localized health impacts is supported by the Act's language and purpose. Protection of public health and welfare is a central purpose of the Act. 42 U.S.C. §7401(b)(1). A source category is listed for regulation under Section 111

[488] *Legal Memorandum*, supra n. 80, at 48.
[489] *Id.* at 48-49.

only if EPA finds that it causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. 42 U.S.C. § 7411(b)(1)(A). Thus, Congress was plainly concerned about the health and welfare impacts of the emissions to be controlled. Given the statutory focus on protecting public health and welfare, a system of emission reduction that fails to protect against impacts on health and welfare cannot be deemed "best" under the statute, and therefore, flexible compliance approaches should not be allowed in other regulations of criteria or hazardous air pollutants.

G. EPA Must Require Absolute Reductions of CO_2 and Co-Pollutant Emissions from Coal-Fired and Natural-Gas Fired Plants in Environmental Justice Communities.

Under the Clean Power Plan, EPA is giving states flexibility to require affected sources to meet the required emission rate through a range of carbon emission reductions measures included in the different building blocks—for example, a coal-fired plant could improve its heat rate, or it could purchase renewable energy credits ("RECs"). In the case of affected sources located in or near environmental justice communities, however, EPA must require absolute reductions of CO_2 and co-pollutant emissions directly from the plants (both coal-fired and natural gas-fired plants), to avoid creating or exacerbating co-pollutant hotspots.

To this end, as we explain below with respect to a cap-and-trade program, spatial restrictions can be imposed on the trading, in this case of renewable energy credits ("RECs"), by sources located in or near environmental justice communities. This can be done by delineating zones where the flow of RECs is prohibited or limited, to ensure that adverse impacts on these communities from trading are minimized. EPA's own guidance suggests that these zones can be defined in terms of non-attainment areas.[490] We suggest that those zones should be defined in terms of hotspots that take into account cumulative impacts. Once state agencies have delineated these zones, they could forbid or limit REC purchases that allow dirty plants to increase or maintain their co-pollutant emissions in these zones. In this way, coal-fired and gas-fired plants in environmental justice communities would have to reduce their emissions rather than purchase RECs.

H. States Must Integrate Environmental Justice Concerns into the Design of Cap-and-Trade Compliance Programs.

EPA's proposal provides states with flexibility to convert the rate-based state goals to mass-based goals, in order to accommodate programs such as the Regional Greenhouse Gas Initiative ("RGGI") and California's Global Warming Solutions Act ("AB32") for compliance under the rule (as well as other similar programs other states decide to create for compliance purposes). 79 Fed. Reg. at 34,897. The proposal explains that emissions trading would allow affected sources whose emissions are higher than the assigned emission standard to comply by

[490] EPA, Office of Air and Radiation, *Tools of the Trade, A Guide to Designing and Operating a Cap and Trade Program for Pollution Control* (June 2003), *available at* http://www.epa.gov/airmarkets/resource/docs/tools.pdf, at 3-22.

purchasing allowances through the trading program. *Id*. at 34,892. To the extent that EPA decides to allow emissions' trading in the final rule, and states decide to incorporate an allowance trading program in their state plans, they *must* effectively integrate environmental justice considerations as they design such a program.

Cap-and-trade programs are widely regarded as having the capacity to generate large emissions reductions. Market-based systems, however, are focused on achieving reductions in the most efficient and cost-effective manner, without regard to the spatial distribution of those reductions. If EPA allows these programs for compliance, states that opt for CO_2 allowance trading systems *must* integrate environmental justice considerations into the design of these programs in order to avoid the risk of co-pollutant hotspots and ensure environmental justice communities receive the benefits of those reductions, as we explain below. By properly integrating environmental justice concerns, the overall emissions reductions achieved by a cap-and-trade program would benefit low income communities, whose health is more likely to be affected from increased pollution levels and who have fewer resources to move out of vulnerable areas.[491]

Given the flexibility available to states in implementing the Clean Power Plan, it is likely that states will consider other compliance measures that pose a similar risk of exacerbating co-pollutant hotspots or depriving environmental justice communities of the benefit of co-pollutant reductions. Implementing Building Block 2, for example, might reduce coal plant pollution in some communities while increasing gas plant pollution in others. A state carbon tax is a potential compliance mechanism that offers the possibility of addressing these impacts by creating a revenue stream that the state could use to finance co-pollutant reductions and other measures to ensure that the benefits of the Clean Power Plan accrue to environmental justice communities.

1. Cap-and-Trade Programs May Heighten the Risk of Co-Pollutant Hotspots.

Allowing affected sources to comply through the purchase of CO_2 allowances may heighten the risk of co-pollutant hotspots. While, as noted above, CO_2 is a global pollutant that does not itself create adverse local impacts, the combustion that generates CO_2 also generates criteria pollutants such as SO_2, NOx, ozone precursors, and hazardous air pollutants that can contribute to create or perpetuate pollution in minority and low income communities which, in many cases are home to the country's dirtiest plants.[492] The degree of harm from co-pollutant emissions varies depending on the population's density and exposure to cumulative pollution impacts.[493] While many co-pollutants are regulated under other Clean Air Act programs and may already be controlled by existing permits, those requirements do not fully eliminate

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[491] Kaswan, *Environmental Justice and Domestic Climate Change Policy*, 38 Envtl. L. Rep. News & Analysis 10,287, 10,293-94 (May 2008), attached as **Ex. 56**.
[492] *Id.* at 10,298. *See also* NAACP, *Coal-Blooded, supra* n. 454.
[493] Kaswan, *Climate Change and Environmental Justice: Lessons from the California Lawsuits*, 5 San Diego J. Climate & Energy L. 1, 23 (2013-2014), attached as **Ex. 57**.

harmful pollution or ensure that actual emissions under a cap-and-trade program will not increase. For example, permitted facilities could increase their actual emissions by operating at higher capacity factors and still remain within the terms of their permits. While the risk of hotspots exists with and without a cap-and-trade program, the ability to purchase CO_2 allowances under such a program could lead to increased emissions that would otherwise not have occurred.[494]

2. Cap-and-Trade Programs May Fail to Properly Distribute Co-Pollutant Benefits.

While cap-and-trade programs may achieve large emissions reductions, they may fail to distribute the benefits of co-pollutant reductions to environmental justice communities. Communities located near plants that reduce CO_2 emissions and purchase fewer allowances (or that do not purchase allowances) will benefit from reduced emissions of co-pollutants, while communities near facilities that purchase more allowances and do not reduce their emissions will not. Even if a facility only maintains its level of emissions, without increasing it, the relevant community will not have obtained a benefit from the co-pollutant reductions that would result from the Clean Power Plan. If the higher-emitting facilities are located in minority and low-income communities, then the program could contribute to intensify environmental justice impacts.[495]

3. To the Extent that EPA Allows Cap-and-Trade Programs for Compliance, the Agency Must Require States to Integrate Environmental Justice Concerns into the Design of Those Programs.

If EPA allows compliance through cap-and-trade programs in the final rule, the agency must require states to effectively integrate environmental justice concerns into the design of those programs in order to address the risk of co-pollutant hotspots and the distribution of benefits of co-pollutant reductions. Relevant statutes or regulations creating the cap-and-trade program must provide for environmental justice protections, which will enable the design of an allowance trading program that addresses these communities' concerns. Below we suggest two ways of incorporating these concerns: first, limitations on trading to address hotspots, and second, the utilization of revenues from allowance auctions for the benefit of environmental justice communities.

a. Incorporate Environmental Justice Protections at the Statutory or Regulatory Level.

If states opt for a cap-and-trade program for compliance, they will likely need to pass a statute or regulation to create it. And when they do so, they must incorporate principles that provide the authority for integrating environmental justice into the design of the program. California's AB32 provides a good example of how to integrate environmental justice

[494] Kaswan, *Environmental Justice and Domestic Climate Change Policy*, supra n. 491, at 10,300-01.
[495] *Id.* at 10,302.

considerations into the design of a cap-and-trade program at the legislative level, provided the legislative program is correctly implemented. AB32 adopted a holistic approach that required the California Air Resources Board ("CARB"), the implementing agency, to adopt regulations that ensured reductions not only of greenhouse gases, but also of co-pollutants, and mandated the program to ensure benefits for environmental justice communities.

Specifically, AB32 provides that, before enacting a cap-and-trade program, the CARB had to consider "the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution," and to design the compliance mechanism in a manner that prevents "any increase in the emissions of toxic air contaminants or criteria air pollutants." Cal. Health & Safety Code § 38570(b)(1)-(2). In adopting the relevant regulations, CARB was required to "[c]onsider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health," and to "[e]nsure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities." *Id.* § 38562(b)(2)-(6).

The law also mandated the creation of an environmental justice advisory committee ("EJAC"), comprised of "representatives from communities in the state with the most significant exposure to air pollution, including, but not limited to, communities with minority populations or low-income populations," to advise it in developing a scooping plan. *Id.* § 38591(a). CARB is also required to ensure that the cap-and-trade program directs public and private investments toward the most disadvantaged communities in the state, and to provide an opportunity for community institutions to participate in, and benefit from state-wide efforts to reduce greenhouse gas emissions. *Id.* § 38565.

The manner in which this legal authority is implemented is critical to ensure that measures to address environmental justice concerns are adequately executed. While providing for the relevant protections in the statute, AB32 is also a good example of how a program that provides legislative protections may still not address environmental justice concerns adequately. In California, environmental justice advocates pushed back on the development of a cap-and-trade program because CARB did not adequately consider alternatives, as required under California land use laws. EJAC's lack of funding was also a major issue. Environmental justice advocates have worked tirelessly to ensure AB32 incorporates the concerns of these communities, including through the promotion of additional legislative solutions to mitigate potential harms and create benefits for these communities, as explained below.[496]

California's AB32 thus provides valuable lessons to other states in the design of a cap-and-trade program at the legislative level. From a practical perspective, however, resources are not available in every environmental justice community, and the degree of public engagement may not be the same as in California, precisely due to lack of resources. Particularly in those

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[496] *See* Kaswan, *Climate Change and Environmental Justice, supra* n. 493; Truong, *Addressing Poverty and Pollution, supra* n. 423.

regions, EPA must step up and advance the concerns of environmental justice communities through targeted information efforts and the provision of financial resources that enables their meaningful participation in the development of a cap-and-trade program.

b. Perform a Cumulative Effects Assessment as Part of Environmental Impact Review.

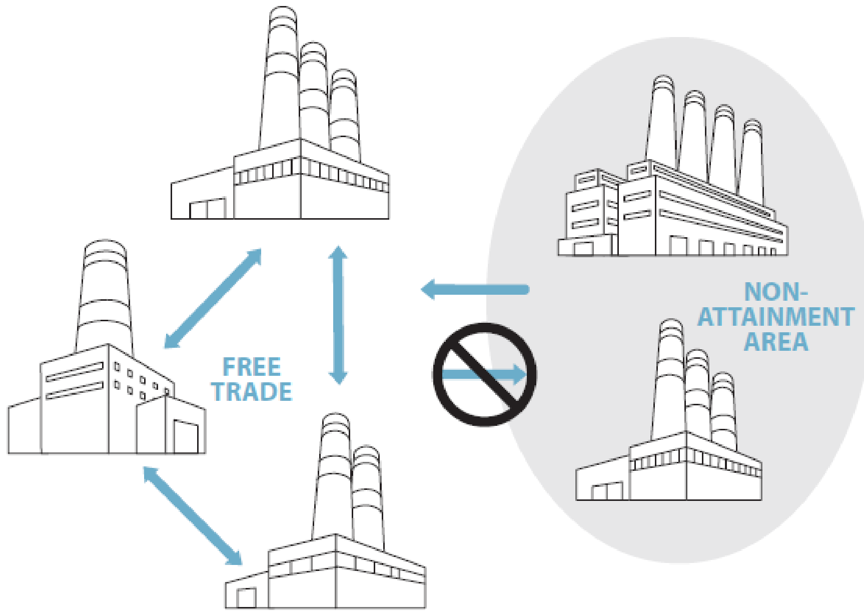
As we discussed above with respect to the performance of an environmental justice analysis, the focus on specific pollutants does not factor in the cumulative effects on minority and low income communities, who are often subject to a multiplicity of environmental and socio-economic impacts. States that opt to comply with the Clean Power Plan through a cap-and-trade program *must* prepare a cumulative impact assessment as part of their environmental impact assessment of such a program, following existing methodologies and EPA's own guidelines that the agency should provide in the Clean Power Plan. This analysis will help inform the exact design of the trading program in a manner that avoids the incidence of hotspots and that distributes the benefits from trading to these communities.

c. Establish Spatial Restrictions on Trading Taking into Account Cumulative Effects.

As EPA has noted in its guidance on the design of a cap-and-trade program for pollution control, one design approach to address hotspots is to introduce spatial restrictions on trading of allowances. If unacceptable pollutant concentrations are expected to occur in a particular area, "trading restrictions could be imposed by introducing 'zones' where net flows of allowances into the sensitive area are prohibited or discounted by an appropriate amount."[497] This would require the relevant state agencies to delineate those zones by identifying areas with high levels of pollution or areas that contain environmental justice communities, the types and levels of emissions in those areas, and the size of the relevant zones according to different criteria.[498] An example of trading restrictions by spatial trading zones is the Los Angeles' Regional Clean Air Incentives Market ("RECLAIM") program, which employed two trading zones—sources in the downwind zone were precluded from trading allowances with zones in the upwind zone.[499]

[497] EPA, *Tools of the Trade, supra* n. 490 at 3-22.
[498] Kaswan, *Environmental Justice and Climate Change Policy*, *supra* n. 491, at 10,305.
[499] EPA, *Tools of the Trade, supra* n. 490 at 3-21.

Fig. 31- Spatial Trading Restrictions



Spatial trading zones can be defined according to a variety of criteria. Size can be evaluated in broad terms, for example, as non-attainment areas (as depicted in Fig. 31 above), or in terms of specific adverse impacts suffered by these communities; i.e., as hotspots. Hotspots can be further delineated not only in terms of proximity impacts, but also of cumulative impacts. Non-attainment zones would be administratively easier to designate, but they could fail to adequately address the localized effects from pollution in environmental justice communities. Zones that more accurately reflect the pollution impacts suffered by these communities would enable a more targeted program, but this would require state agencies to obtain detailed information about the distribution of pollution. As we discussed above, an environmental justice analysis would provide states and EPA with adequate information to define the size of these zones in terms of hotspots.

Once state agencies have defined these zones, they could impose restrictions such as forbidding the trading of allowances that increase, or that simply maintain, co-pollutant emissions in these zones, particularly by the dirtiest plants. States could also discourage trading by introducing an obligation to maintain a greater number of allowances per ton of emissions in these zones,[500] or by charging higher allowance prices to facilities located in these areas. The latter approach would not prohibit trading, but would make it more expensive to trade in those zones. This would provide these sources with an incentive to reduce their own emissions rather than purchase allowances.[501]

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[500] *Id.*

[501] Kaswan, *Environmental Justice and Climate Change Policy*, *supra* n. 491 at 10,306.

d. Finance Co-Pollutant Reductions with Revenues from Allowance Auctions.

If allowances under a cap-and-trade program are auctioned, states should use a portion of these revenues to address the reduction of co-pollutants in environmental justice communities through other measures outside of the cap-and-trade mechanism. These revenues could be used to finance targeted investments in demand-side energy efficiency, renewable energy, and in projects to revitalize environmental justice communities.[502] Residents of environmental justice communities should participate in the selection of the activities to be funded. [503]

In California, for example, SB 535 mandates the California Department of Finance ("DOF") to allocate 25 percent of AB32 auction revenues to projects that provide benefits to disadvantaged communities, with at least 10 percent to be spent directly in those communities.[504] The bill requires CalEPA to identify disadvantaged communities based on geographic, socioeconomic, public health, and other environmental hazard criteria, including "[a]reas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation," and "[a]reas with concentrations of people that are of low income, high unemployment, low levels of homeownership, high rent burden, sensitive populations, or low levels of educational attainment."[505]

A companion bill, AB 1532, required the Department of Finance, in consultation with CARB and any other relevant state entity, to develop a three-year investment plan and to submit it to the Legislature for approval. Subsequently, the DOF will allocate funding to these programs through the annual budget process. In developing the investment plan, the bill requires DOF to ensure that the revenues facilitate the achievement of greenhouse gas reductions in the state (for example, through energy efficiency and renewable energy generation), foster job creation by promoting emissions reductions projects carried out by California workers and businesses, and direct investments towards the most disadvantaged communities and households in the state. The bill also mandates a public process to determine how to allocate these revenues; specifically, it required CARB to hold at least two public workshops in different regions of the state and one public hearing prior to DOF submitting the investment plan.[506]

Once again, California provides a useful lesson on the need to implement legislative mandates properly. The funding allocations from SB535 were delayed when the Governor

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[502] *See* AB32 Environmental Justice Advisory Committee, *Initial Recommendations to Inform Development of the 2013 to the AB32 Scoping Plan* (Aug. 6, 2013), attached as **Ex. 58**, at 5.
[503] *See* Truong, *Addressing Poverty and Pollution, supra* n. 423; Kaswan, *Environmental Justice and Climate Change Policy*, *supra* n. 491, at 10,306.
[504] Truong, *Addressing Poverty and Pollution*, *supra* n. 423.
[505] *Id.* at Section 2.
[506] Cal. Health & Safety Code § 39716.

borrowed the cap-and-trade funds, ignoring the state's investment plan.[507] It is critical that states implement the programs they create to improve the health and environment of low income communities. If these investment programs become part of the state plan, EPA should require their compliance as part of the overall plan reporting process. EPA should require states to submit detailed information that shows that the earmarked funds are being used in projects that benefit environmental justice communities.

e. Other Considerations in Designing a Cap-and-Trade Program

i. States Must Set a Stringent Cap.

The cap should be stringent enough to ensure emissions' reductions that truly achieve the state goal. Under the Acid Rain Program, stringent reduction requirements enabled significant reductions in SO_2. More recently, under California's AB32 the cap in 2013 was set at 2 percent below the emissions level forecast for 2012. The cap declined 2 percent in 2014 and will decline 3 percent annually from 2015 to 2020.[508]

In addition, and related to the above requirement, states must not over-allocate allowances. The RECLAIM trading program for criteria pollutants provides a good example of the consequences of over-allocation—large utilities subject to the program purchased allowances instead of adopting control technology, which failed to generate emission reductions.[509]

ii. States Should Not Distribute Free Allowances.

While several cap-and-trade programs (such as AB32)[510] provide for free allocation of allowances during the initial stages, we believe that states should auction these allowances and should not distribute them for free.[511] Requiring sources to pay for the right to pollute would force them to internalize these costs, and would reduce the potential for windfall profits. It would also provide revenues to address environmental justice concerns, as discussed above.[512]

iii. Offsets Should not be Permitted for Compliance.

In the proposal, EPA specifies that it is not proposing that out-of-sector GHG offsets could be applied to demonstrate CO_2 emission performance by affected EGUs in state plans. But the agency does raise the possibility that "emission limits for affected EGUs that are included in state plans could still include provisions that provide the ability to use GHG offsets

[507] Truong, *supra* n. 423, at 518.
[508] CARB, *Overview of ARB Emissions Trading Program* (Oct. 20, 2011), attached as **Ex. 59**, at 1.
[509] Kaswan, *Environmental Justice and Climate Change Policy*, *supra* n. 491, at 10,296.
[510] CARB, *Overview of ARB Emissions Trading Program*, supra n. 508, at 1.
[511] *See* AB32 Environmental Justice Advisory Committee, *Initial Recommendations, supra* n. 502, at 5.
[512] Kaswan, *Environmental Justice and Climate Change Policy*, *supra* n. 491, at 10,307.

for compliance with the emission limits, provided those emission limits would achieve the required level of emission performance for affected EGUs.” 79 Fed. Reg. at 34,910.

Although existing GHG cap-and-trade programs like AB32 and RGGI[513] allow the use of offsets, EPA must not allow states that design an allowance trading program for compliance with the Clean Power Plan to reduce emissions through offsets. Allowing regulated facilities to purchase allowances from outside the cap-and-trade program’s scope would enable those facilities to continue emitting or would increase emissions of co-pollutants without a corresponding decrease in emissions from other facilities covered by the program, and environmental justice communities would not obtain the benefits of co-pollutant reductions.[514] In addition, use of certain offsets, such as those resulting from biological carbon sequestration (for example, forestry), would complicate emissions’ monitoring, as these projects are difficult to verify.[515]

iv. States Should Impose Heightened Monitoring and Reporting Requirements on Facilities Located Near Environmental Justice Communities.

Once the cap-and-trade program is in place, state regulators should monitor facilities located in or surrounding these communities to ensure compliance with their obligations under the program. These facilities could be required to install additional monitors, and to report specific information on the emissions of co-pollutants tied to the purchase of allowances. Environmental justice communities should be encouraged to report any actions by facilities that they believe are in violation of these requirements, and should have access to information on these firms’ trading transactions and reports on emission levels.

VIII. Economic Justice

Investments in energy efficiency, clean energy, and other measures to comply with the Clean Power Plan will produce major additional benefits throughout the U.S. economy, making the clean energy economy a major new engine of U.S. job creation. Renewable energy has become cost competitive with fossil fuels, including coal, oil, and natural gas, as well as with nuclear power. In addition to reducing carbon emissions, the ancillary benefits of the Clean Power Plan--developing renewable energy, energy efficiency and a modernized, smart power grid—will, when combined with high road employment practices, create millions of good jobs for people who desperately need them, especially people from economically and environmentally distressed communities.

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513 CARB, *Overview of ARB Emissions Trading Program*, supra n. 508; RGGI, *CO_2 Offsets*, http://www.rggi.org/market/offsets (last visited Nov. 25, 2014). For programs that allow offsets, such as RGGI and AB32, the corresponding emissions standard should be more stringent than the state goal to account for those reductions.

514 Kaswan, *Environmental Justice and Climate Change Policy*, *supra* n. 491, at 10,302.

515 *Id.* at 10,298.

There are clear environmental and public health benefits of replacing fossil fuels with energy efficiency and clean energy. However, we cannot ignore the fact that specific jobs will be lost and specific communities will be affected as we make the transition away from fossil fuels. These economic impacts will affect certain communities, states, and regions much more than others, and we need to ensure that the growth of the clean energy sector reaches those most in need of the economic benefits of that growth. The Clean Power Plan state implementation process provides tremendous opportunities for state and federal policymakers to take concrete policy steps to address the fears of low income and working class communities and union representatives in carbon-intensive sectors that a market-driven clean energy transition means economic insecurity for them. Government has a key role in helping to drive a fair and just transition to a clean energy economy that will maximize investments in economic development, provide security to affected workers, and protect the tax base by creating lasting, good jobs in impacted communities.

A. States Must Craft Plans that Make Expanded Use of Renewable Energy and Energy Efficiency, While Prioritizing the Creation of Good Clean Energy Jobs.

Renewable energy and energy efficiency resources are making up an increasing percentage of America's energy mix. In the past few years, renewable energy has experienced great growth and has become cost-competitive with fossil fuels, with wind prices decreasing overall on average by 58 percent and solar photovoltaics by 78 percent over the last five years, primarily due to technological improvements that have enabled projects to operate at higher capacity factors, as well as due to a decline in the prices of inputs in the manufacturing supply chain.[516] Wind turbine costs, for example, have decreased 30 percent since 2008.[517] These trends will continue and renewables will increasingly become more cost-competitive than fossil fuels. In addition, energy efficiency programs have grown at an accelerated rate since the 2000s, from total spending was $1.6 billion in 2006 to $6.3 billion in 2013.[518] These expenditures are yielding significant energy savings. Funding for customer energy efficiency programs is expected to continue rising in the future. As a result of this expansion, jobs in these industries are experiencing, and will continue to experience great growth.

Numerous sources have noted clean energy's potential for job creation. A report by the Worldwatch Institute and the Center for American Progress noted that renewable energy creates more jobs per unit of energy produced and per dollar spent than fossil fuel technologies do.[519] The Metropolitan Policy Program at Brookings has also found that, as far back as 2010, 2.7 million people were employed in the clean energy sector whereas only 2.4 million people

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[516] Lazard, *supra* n. 172, at 9.
[517] Int'l Renewable Energy Agency, *Rethinking Energy 2014* (Sept. 2014), *available at* http://www.irena.org/rethinking/Rethinking_FullReport_web_print.pdf, at 15.
[518] *Id*. at v.
[519] Worldwatch Institute & Center for American Progress, *American Energy: The Renewable Path to Energy Security* (Sept. 2006), *available at* http://www.worldwatch.org/files/pdf/AmericanEnergy.pdf, at 10.

were employed in the fossil fuel sector.[520] In addition, AWEA reported that in 2012 more than 80,000 Americans were already employed full-time in the wind industry sector.[521] Finally, analysis by the Center for American Progress has concluded that twice as any medium and high credentialed jobs are being created in the clean energy industry in comparison to the fossil fuels' industry,[522] and clean energy investments generate about 3.2 times the number of jobs as does investing the same amount of money in the fossil fuel sector.[523] Thus, clean energy jobs pay more overall, and those jobs are of better quality.

Carbon standards for existing power plants that include significant investments in both renewables and demand-side energy efficiency also have the potential for robust job growth. NRDC's proposal for how the EPA could shape these standards, which includes a significant expansion of energy efficiency, concludes that limits on carbon pollution from power plants have the potential to save Americans $37.4 billion on their electric bills by 2020 while creating more than 274,000 jobs.[524] Because clean energy investments require more employment per unit of activity, others have noted that investments in clean energy will result in a net increase of 2.7 million jobs.[525] In order achieve this goal Pollin and Boyce have called for reducing energy consumption 30 percent by 2030 through efficiency improvements as well as renewable resources.[526] Other academics have also concluded that hundreds of thousands of jobs can be created by California further expanding energy efficiency programs.[527] In sum, renewable energy and energy efficiency contribute to create safer, long-term jobs while providing power at a lower cost.

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[520] Muro et al., Metropolitan Program at the Brookings Institute, *Sizing the Clean Economy: A National and Regional Green Jobs Assessment* (July 13, 2011), *available at* http://www.brookings.edu/research/reports/2011/07/13-clean-economy, at 4, 19.

[521] *Assessing the Efficiency and Effectiveness of Wind Energy Incentives: Joint Hearing Before the Oversight Subcomm. and Energy Subcomm. of the H. Comm. on Science, Space, and Technology*, 114th Cong. (Apr. 26, 2013) (statement of Rob Gramlich, CEO of AWEA), *available at* http://science.house.gov/hearing/oversight-subcommittee-and-energy-subcommittee-joint-hearing-assessing-efficiency-and, at 1.

[522] Pollin et al., Center for American Progress/PERI, *The Economic Benefits of Investing in Clean Energy: How the Economic Stimulus Program and New Legislation can Boost U.S. Economic Growth and Employment* (June 2009), *available at* http://cdn.americanprogress.org/wp-content/uploads/issues/2009/06/pdf/peri_report.pdf, at 38.

[523] *Id*.

[524] NRDC, *New Carbon Pollution Standards Can Save American Households $13 Billion on Electric Bills, Create 274,000 Jobs*, http://www.nrdc.org/air/pollution-standards/state-benefits.asp (last visited Nov. 24, 2014).

[525] Pollin & James Boyce, PERI, *An Egalitarian Program for Building a Clean-Energy U.S. Economy*, Discussion Paper Prepared for Labor Network for Sustainability Conference (Jan. 16, 2014), attached as **Ex. 60**, at 5.

[526] *Id*. at 1.

[527] Roland-Holst, D., U.C.-Berkeley, *Energy Efficiency, Innovation, and Job Creation in California* (Oct. 2008), attached as **Ex. 61**, at 4.

The Clean Power Plan can help accelerate the clean energy economy and create good jobs by allowing states to achieve their targets through the implementation of renewable energy generation and energy efficiency. The proposal would result in increased clean energy sector jobs and an estimated decrease of about nine percent in electricity bills by 2030. 79 Fed. Reg. at 34,934. The flexibility granted to states to achieve their targets with more renewable energy and energy efficiency than EPA has estimated for purposes of its state goals' calculation means a higher potential for new jobs in solar installation, wind infrastructure development, and construction of homes and businesses that are more energy-efficient, among other job options. Median wages are 13 percent higher in clean energy jobs than the median United States wages.[528]

These projections are borne out in practice by new research which shows that, in California, strong federal and state clean energy policies, combined with high road employment practices, have resulted not only in substantial carbon emissions reductions but in stable, family-sustaining careers.[529] As a result of these policies, California's use of electricity from renewable sources increased from 11 percent in 2008 to nearly 20 percent in 2013. During the same time period, the report finds that more than 15,000 new jobs have been created by California's solar construction boom, with workers building solar arrays earning on average $78,000 a year plus health and other benefits.[530]

California's experience supplies a road map for states seeking to develop state plans that combine carbon emissions reductions with the creation of good jobs and economic development. The report lists three key ingredients for success. The first ingredient, strong federal action, included the Obama Administration's American Recovery and Reinvestment Act (ARRA) of 2009, which reserved more funds for clean energy than had been done at any time in our nation's history, loan guarantees that helped solar energy to take off in the depths of the Great Recession, and the Federal Business Energy Investment Tax Credit, which provides a 30 percent credit to residential, commercial, and utility scale solar systems. The second ingredient, California's aggressive climate change policies, includes AB 32, which requires a steep reduction in greenhouse gas emissions, and SB X1-2, which expanded California's RPS to an ambitious 33 percent target by 2020.[531]

The third vital element of the equation mentioned in the report was "high road" job creation and construction policies: utility-scale solar projects that receive federal subsidies fall under the Davis-Bacon Act, which requires that prevailing wages and benefits be paid. Furthermore, California is not a right-to-work state and as a result prevailing wages in

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[528] Muro, et al, *supra* n. 520, at 23.
[529] Philips, P., U.C.-Berkeley, *Environmental and Economic Benefits of Building Solar in California* (Nov. 10, 2014), *available at* http://laborcenter.berkeley.edu/environmental-and-economic-benefits-of-building-solar-in-california-quality-careers-cleaner-lives/.
[530] *Id.* at 3.
[531] *Id.* at 4.

construction tend to be the collectively bargained rate that includes good wages with decent benefits and contributions to apprenticeship training. As the report notes, "the California solar boom has not only prepared California for a future of energy independence, it is preparing a new generation of California blue-collar workers for a future of skilled and productive work and a life of financial security".[532]

The report contrasts California's "high road" employment practices with work on some federally-subsidized solar projects in right-to-work states, where nonunion rates prevail: "in these cases, workers are often obtained from temporary labor agencies; they earn low wages with limited benefits and they have little access to training or career advancement. In California, by contrast, strong unions and strong prevailing wage laws combine to create green construction projects that also build the skills of the local construction labor force and improve the career opportunities of many new entrants into the industry".[533]

Thus, States must take the driver's seat in crafting compliance plans expand renewable energy and energy efficiency, while also prioritizing the creation of good, clean energy jobs to promote state and local economic development and improve community and workers' livelihoods.

B. States Should Require Affected Sources to Put in Place Comprehensive Workers' Transition Policies.

For a number of years, the electric sector has been moving away from coal towards natural gas and renewable energy. In our joint comments to EPA's 111(b) proposal, we documented that coal generation fell from over 2 billion MWh in 2007 to 1.58 billion MWh in 2013. Older and less-efficient power plants have and continue to retire due to competition with other generation resources and environmental requirements, with approximately 20 GW of coal retired between 2008 and 2013.[534] The EIA estimates that, regardless of any impending environmental regulations, there will continue to be a shift away from fossil-fuel-fired generation towards a renewable energy economy.[535] The EIA predicts that by 2040, renewables will account for almost one third of the growth of generation resources.[536]

In the course of developing their plans to achieve the state goals under the Clean Power Plan, states should continue to move away from coal, which is no longer economical and results in major environmental harms. In incorporating policies to continue to move away from coal, states must also establish measures to ensure that owners and operators of coal-fired power plants that will reduce or terminate their operations protect their workforce and guarantee that their workers can transition smoothly to the coming clean energy economy. In other

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532 *Id.*
533 *Id.*
534 Sierra Club, *supra* n. 115, at 14-15.
535 EIA, *AEO2014 Early Release Overview*, *supra* n. 56, at 2.
536 *Id.* at 7.

words, state plans must require owners and operators of coal-fired power plants to put in place comprehensive transition policies to minimize the impacts of potential job losses and incentivize their participation in the growing renewable energy economy. To this end, owners of power plants that will have to reduce their utilization or close should have policies in place specifically geared to workforce development, family-sustaining employment, and livelihood guarantees (for example, health care, pensions during some period after job loss, and severance packages). As we describe below, this may require government financial assistance.

C. The Federal Government and the States Should Ensure Funding for Workers and Communities that Depend on Fossil Fuel-Fired Power Plants.

The federal government and the states should ensure that funding mechanisms are in place to support workers, as well as the communities whose livelihoods depend on fossil fuel-fired power plants, through the transition process. As UCS notes in its comments to the Clean Power Plan, the federal government administers several programs that support worker retraining and community development. For example, the Obama Administration designated eight counties in southeastern Kentucky as a "Promise Zone"[537] to channel federal grants and assistance from various federal agencies, including housing, education, economic development, agriculture, and safety. The federal government should make use of existing programs (or create new programs) to provide targeted resources to affected communities and to help coal states diversify their economies. Federal agencies should work with Congress to enact legislation that supports displaced workers in the coal mining, coal-fired power plants, and related industries.[538]

In crafting other financing and support programs, a useful precedent to consider is the Worker and Community Transition ("WCT") program, a Department of Energy ("DOE")-administered program that took place between 1994 and 2004. WCT targeted communities whose livelihoods were heavily dependent on the nuclear industry, and who faced displacement due to nuclear retirements. The WCT looked specifically at the communities that benefited from the grants.[539] WCT provided grants along with other forms of assistance to help diversify the economic livelihood of affected communities. Under the program, DOE encouraged these groups to develop Community Reuse Organizations ("CROs") eligible for funding to address the impacts in their specific neighborhoods.[540] DOE estimated that with the

[537] Shear, M., *Obama Announces 'Promise Zones' in 5 Poor Areas*, The New York Times, (Jan. 9, 2014), *available at* http://www.nytimes.com/2014/01/10/us/politics/obama-announces-promise-zones-in-5-stricken-areas.html?_r=1
[538] For more discussion on worker transition issues, see the comments submitted to this docket by UCS.
[539] Pollin, R., *Coal Miners and the Green Agenda,* New Labor Forum (Jan./Feb. 2014), at 88-89. This article is available for purchase at http://nlf.sagepub.com/content/23/1/88.full.
[540] Dep't of Energy, *Community Assistance*, http://energy.gov/lm/services/property-management/community-assistance (last visited Nov. 24, 2014).

funds awarded to these communities, the CROs collectively created a total of 50,934 jobs at a cost of $5,719 per job.[541]

Other reviews of the WCT have concluded that the program was effective, but "the most serious problem facing the energy-impacted communities, however, was the lack of a basic regional economic development and industrial diversification capacity for most of the regions."[542] Although specifically targeting those facing dislocation due to nuclear retiring, the program addressed the same type of problem that workers in the coal industry are now facing as coal becomes increasingly less competitive vis-à-vis other generation resources and pollution caused by coal is subjected to environmental regulations.

The federal government should take a leading role to ensure economic opportunities at the regional level are available to these workers and their communities, particularly in states without a strongly diversified economic base. According to an analysis prepared by the staff of the BlueGreen Alliance,[543] these actions could include:

- Executive Orders:
    - Designating EPA and the Departments of Labor, Commerce, Energy, Transportation, and Agriculture to provide information on resources already available that would connect the need for economic and workforce development with areas that are either already experiencing the energy transition or may do so soon;
    - Ordering EPA and the Departments of Labor, Energy, Commerce, Agriculture, Education and Transportation to sign a memorandum of understanding to collaborate on linking workforce and communities in regions affected by energy transition to jobs, training, education and economic development opportunities;[544]
    - Activating the Department of Labor's Employment and Training Administration to assess where resources can be utilized to target communities affected by the energy transition;
    - Revitalizing and prioritizing the Green Jobs Act elements of the Energy Training Partnership grants, and explicitly connecting its mission to supporting communities affected by the energy transition;

[541] *Id*.

[542] Lynch & Kirshenberg, *Economic Transition by the Energy-Impacted Communities*, Commentary (Fall 2000), attached as **Ex. 62***,* at 2.

[543] BlueGreen Alliance staff, *Recommended Next Steps on Integrating Climate Change and Economic Development Policies* (2013) (unpublished document available from BlueGreenAlliance).

[544] Presently existing programs that can support economic development in regions affected by the energy transition include Industrial Development Revenue Bonds, Economic Adjustment Assistance, Economic Development Agency Planning, Local Technical Assistance Programs, Rural Energy for America Program, Clean Renewable Energy Bonds, and a number of the programs within the Economic Development Administration, especially those within its Environmentally Sustainable Development investment priority. *Id*.

- Supporting the importance of collective bargaining to our current and future economy; and
- Within the confines of existing law, recreating the Clean Air Employment Transition Assistance (Section 326 of Clean Air Act, subsequently repealed by the Workforce Investment Act of 1998) through utilization and temporary redirection of National Emergency Grant Program to directly target areas affected by the energy transition.

- Further appropriations:
  - Calling for increased funding for Economic Development Administration's programs (specifically their Environmentally Sustainable Development investment priorities), the Department of Labor's Community Based Job Training Grants and Adults and Dislocated Worker Program, and Energy Training Partnership grants.

- New legislation:
  - Directing worker transition assistance, expanded to include all coal sector workers, not only miners, modeled on Sen. Byrd amendment to 1990 Clean Air Act Amendments, Climate Change Worker Adjustment Assistance from American Clean Energy and Security Act ("ACES").

States must continue to turn away from fossil fuels by taking advantage of economic forces and actively engaging in specific areas experiencing job losses. Thus, they should also support the development of strong support plans to help workers and communities in transition, which should include financial assistance. For example, one of the objectives in Washington State's SB 5769, along with requiring greenhouse gas emissions reductions from large coal-fired electric power generation facilities, is to provide financial assistance to communities who are affected by the transition away from coal. The bill fulfils this purpose by mandating that the Community Economic Revitalization Board ("CERB") and the Public Works Board each find new projects for redevelopment in the region.[545] It also requires qualifying facilities to offer financial aid to the affected community that is "equivalent to the amount of tax benefits received from the sales and use tax exemptions on coal."[546]

States should also engage the private sector and civil society to fund initiatives to support workers and their communities. The Solar Community Initiative, administered by the World Wildlife Fund and executed by the solar firm Geostellar, provides useful lessons for the design of such programs.[547] Under that program, employees can install rooftop solar on their homes at discounted prices – 35 percent below the national average for solar- and pay 50

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[545] Wash. S. Bill Report SB 5769 (2011), *available at* http://apps.leg.wa.gov/billinfo/summary.aspx?bill=5769&year=2011 (last visited Nov. 25, 2014), at 5.
[546] *Id*.
[547] Cusick, D., *Companies Begin to Offer Discounted Solar Energy as a Worker Benefit,* E&E (Oct. 23, 2014), *available at* http://www.eenews.net/climatewire/stories/1060007766.

percent less than the average grid-delivered electricity in their bills. This is an example of how renewable energy companies are beginning to offer solar energy as a workers' benefit. States must work with renewable energy industry stakeholders to expand the availability of these programs to workers in affected communities. Solar panels not only reduce consumers' electricity bills; workers whose job is to install solar panels are also increasingly becoming aware of how cleaner technologies are replacing dirtier forms of electricity, with environmental benefits. This type of incentive offers a way to attract and retain workers to clean energy jobs, and also helps pre-qualify people in those jobs for the said benefits.

Energy efficiency can also be channeled towards benefiting affected communities, and states should encourage affected sources to invest in these measures. For example, weatherization assistance programs can be utilized in low-income and minority areas to help shrink the energy affordability gap. According to the DOE, investments in weatherization generate $2.51 in energy savings while reducing energy bills by $1.80.[548] Policy Matters Ohio and Environmental Health Watch has assessed Ohio's Home Weatherization Assistance Program, concluding that it has generated jobs, reduced pollution, and lowered consumers' energy bills by more than 20 percent.[549] This will not only create jobs in areas burdened by the costs of electric bills (for example, more than 300,000 Ohio households with incomes at or below the 50 percent federal poverty level pay over 30 percent of their annual income to energy bills[550]), but it will further promote investment in local economies.

IX. A State Carbon Tax as a Compliance Mechanism

A. A State Carbon Tax is an Effective Means of Compliance

1. Carbon Taxes Reduce CO_2 Emissions

It is axiomatic that taxation is an effective means of reducing production and consumption of whatever is being taxed, and as a result, the literature is thick with studies of how a carbon tax would reduce CO_2 emissions.[551] Using a wide variety of models and price assumptions, the results are always the same: a carbon tax reduces both greenhouse gas emissions in general and EGU CO_2 emissions in particular.

For example, MIT's Emissions Prediction and Policy Analysis ("EPPA") model shows that a $15/ton tax would reduce coal-fired EGU CO_2 emissions by almost 15 percent within five

[548] *Id.* at 2.
[549] Woodrum & Jacob, Policy Matters Ohio/Environmental Source Watch, *Weatherizing Homes of Ohio's Low-Income Families: Reduces pollution, cuts energy bills, creates jobs* (Oct. 2014), attached as **Ex. 63**, at 1.
[550] *Id*. at 4.
[551] We bear in mind George Orwell's observation that "we have now sunk to a depth at which the restatement of the obvious is the first duty of intelligent men."

years.[552] EIA's National Energy Modeling System ("NEMS") model demonstrates that a national carbon tax starting at $14/ton in 2010 would reduce coal-fired EGU CO_2 emissions by 50 percent from the 2030 BAU projections.[553] The U.S. Regional Energy Policy Model ("REPM") demonstrates that a national carbon tax starting at $20/ton in 2013 would reduce CO_2 emissions by 14 percent from 2006 levels by 2020.[554] And the Stanford-NEMS model shows that implementing a $20/ton emissions tax in 2014 would, by 2020, reduce EGU CO_2 emissions by 17 percent from 2005 levels.[555] Going further into the specific application of a carbon tax to coal-fired EGUs, other studies show that it is the most effective and cost-efficient way to decrease their heat rate (and thus increase their efficiency).[556]

The most recent example of a carbon tax successfully reducing EGU CO_2 emissions comes from Australia, which introduced an A$23/ton tax as of July 1, 2012. Within nine months, demand for power dropped by 2.2 percent, and the carbon intensity of power on the national grid dropped by almost 5 percent, from 1,840 lbs CO_2/MWh to 1,740 lbs CO_2/MWh.[557] In the year ending June 30, 2012, the power sector emissions were 193.5 MMT; the year ending June 30, 2013, those emissions were 181.3 MMT, a 6.3 percent decrease (Quarterly Update of Australia's National Greenhouse Gas Inventory: June Quarter 2013, p. 3); by March, 2014 (the latest period for which there is published data), power sector emissions were further reduced to an annual rate of 176 MMT, an overall decrease of 9 percent in less than two years. Quarterly Update of Australia's National Greenhouse Gas Inventory: March 2014, p. 6.

Nor does a carbon tax have to be national to be effective: British Columbia ("B.C.") is showing how a carbon tax implemented in just one area of a country successfully reduces emissions even if the rest of the country has not adopted it. B.C. implemented the tax on a

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[552] Metcalfe, G., Brookings Inst.: The Hamilton Proj., *A Proposal for a U.S. Carbon Tax Swap*, Discussion Paper 2012-07 (Oct. 2007), *available at* http://www.brookings.edu/~/media/research/files/papers/2007/10/carbontax%20metcalf/10_carbontax_metcalf.pdf.

[553] Shapiro et al., U.S. Climate Task Force, *Addressing Climate Change Without Impairing the U.S. Economy: The Economics and Environmental Science of Combining a Carbon-Based Tax and Tax Relief* (2008), *available at* http://www.sonecon.com/docs/studies/CarbonTaxReport-RobertShapiro-2008.pdf, at 17.

[554] Rausch & Reilly, MIT Joint Prog. on the Science and Policy of Global Change*, Carbon Tax Revenue and the Budget Deficit: A Win-Win-Win Solution?*, Report No. 228 (August 2012)*, available at* http://globalchange.mit.edu/files/document/MITJPSPGC_Rpt228.pdf, at 9.

[555] Wara et al., Stanford Fed. Energy Policy Lab., *Analysis of the Climate Protection Act of 2013*, Stanford Law and Economics Olin Working Paper No. 459 (June 18, 2013), *available at* http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2392656, at 11.

[556] Linn et al., Resources for the Future, *Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act*, RFF DP 13-05 (Feb. 2013), *available at* http://www.rff.org/rff/Documents/RFF-DP-13-05.pdf, at 54.

[557] Dennis, G., Clayton Utz, *Australia: What has been the effect of Carbon Price on the electricity market?* http://www.mondaq.com/australia/x/235844/Oil+Gas+Electricity/What+has+been+the+effect+of+the+Carbon+Price+on+the+electricity+market&email_access=on (last visited Nov. 30, 2014).

broad range of fossil fuels (gasoline, diesel, natural gas, heating oil, propane and coal) beginning in 2008 at C$10/ton, and increased it C$5 annually until it reached C$30/ton in 2012. The results were impressive: by 2011 (the most recent year for which there were data), GHG emissions had declined by 10 percent in B.C., compared to a 1 percent decline for the rest of Canada. By 2012, while per capita consumption of petroleum fuels increased by 3 percent in the rest of Canada, they declined by more than 16 percent in B.C.[558] Nor did the tax adversely affect B.C.'s economy; in fact, during that period, B.C.'s GDP per capita increased more than the GDP per capita of the rest of Canada.[559]

2. The Advantages of a Carbon Tax

a. Economic Advantages

Among economists, there is consensus that a carbon tax is a more economically efficient means of reducing CO_2 emissions than any of the various regulatory mandates contemplated by the proposed rule. In fact, because the regulatory commands contemplated by EPA's BSER building blocks increase the cost of such emissions and those costs will be passed on, to some extent, to consumers, they can also be said to impose a price on CO_2, albeit one that is economically less efficient than a carbon tax.

b. Administrative Advantages

A carbon tax creates economic incentives for each of EPA's building blocks by discouraging each fuel's use in exact proportion to its end-use CO_2 emissions, and thus encourages all emissions reductions that cost less than the tax. However, it is simpler to implement and administer than the Building blocks because all affected EGUs are already required to monitor and report their CO_2 emissions;[560] after that, it is a simple arithmetical exercise to multiply the reported emissions by the tax rate and send a check to the State treasury. A carbon tax thus avoids the need for complex administrative and regulatory action by multiple state agencies.

c. Revenue to Offset Impacts on Low Income Households and Fenceline Communities

To the extent that carbon reductions increase electricity rates, these costs are regressive, *i.e.*, as a share of household income they will fall more heavily on lower-income households than on higher-income households. This is because, in general, lower-income

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[558] Petroleum consumption is the most useful B.C. statistic because B.C. does not have any coal-fired EGUs, and its one baseload natural gas-fired EGU—Burrard—is scheduled to shut down in 2016.
[559] Beaty et al., *The shocking truth about B.C.'s carbon tax: It works*, The Globe and Mail (July 9, 2014), *available at* http://www.theglobeandmail.com/globe-debate/the-insidious-truth-about-bcs-carbon-tax-it-works/article19512237/.
[560] 40 C.F.R. § 98.2 (GHG Reporting Rule monitoring requirements).

households spend a higher percentage of their income on energy and other goods whose prices would be increased by the resulting increase in electricity prices. For example, a $15 carbon tax would burden the poorest 10 percent of households on average by about 3.5 percent of annual income, almost 7 times greater than the 0.6 percent burden that would fall on the richest households.[561]

Unlike other regulatory mechanisms that could be used to meet the Plan's targets, however, a carbon tax generates revenue that can be used to offset that burden on lower-income households. One paper estimates that (for a national carbon tax), just 11 percent of the revenue would suffice to hold the bottom two deciles of households by income harmless, 18 percent would be enough to protect the bottom three deciles, and 35 percent would suffice to cover the entire bottom half of households.[562] Carbon tax revenues would enable states to fully compensate lower-income households for these regressive effects; states could return this revenue by any one of a number of mechanisms, such as lump-sum payments via Electronic Benefits Transfer or reductions in state income or other regressive taxes. States could also direct carbon tax proceeds to EE programs in low income communities, offsetting any electricity rate increases with reduced consumption.

While cap and trade also generates such revenues (as does ISO-pricing, discussed below), a tax has decided advantages over each. A tax is economically more efficient than a cap and trade system because (1) it provides price certainty as opposed to the fluctuating cost for cap and trade allowances,[563] and (2) there is no market for permits that is subject to manipulation: "The great potential for fraud attendant on such a system creates significant doubt about its effectiveness, as experience has shown in both theory and practice in the gyrations of the European ETS."[564] A carbon tax is also administratively superior. A tax requires emission reporting and arithmetic; a cap and trade system requires the state to allocate allowances, conduct auctions, create an allowance registry, monitor trades and positions, and possibly enforce a price floor/ceiling. Moreover, a state could easily expand a tax to cover any additional source categories that were regulated under section 111(d); in contrast, it is unclear how states could add new source categories to existing cap-and-trade programs. Because the Act requires compliance for each source category, states would presumably have to set up separate cap-and-trade programs for each regulated source category.

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[561] Mathur & Morris, Brookings Inst., *Distributional Effects of A Carbon Tax in Broader U.S. Fiscal Reform* (Dec. 14, 2012), *available at* http://www.brookings.edu/~/media/research/files/papers/2012/12/14%20carbon%20tax%20fiscal%20reform%20morris/14%20carbon%20tax%20fiscal%20reform%20morris.pdf, at 6.
[562] *Id.* at 14.
[563] Mankiw, N. G., *Smart Taxes: An Open Invitation to Join the Pigou Club,* 35 Eastern Economic Journal 14-23 (2009), *available at* http://scholar.harvard.edu/files/mankiw/files/smart_taxes.pdf, at 18.
[564] Green *et al.*, Am. Enterprise Inst., *Climate Change: Caps vs. Taxes* (June 2007), at 5.

A carbon tax also has advantages over another carbon pricing compliance mechanism proposed by Great River Energy and the Brattle Group ("ISO pricing").[565] ISO pricing involves ISOs imposing a carbon price on affected EGUs via the bid mechanisms used for wholesale electricity markets, which is an economically efficient means of incentivizing dispatch. However, this approach has the political problem of potential transfers from rate payers in one state to out-of-state entities; a state carbon tax ensures that the revenues remain in-state. A second problem is that many states are only partially covered by an ISO; some have more than one, some have one or more in addition to areas without an ISO, and some states have no ISO at all. Addressing such situations in a SIP would greatly increase complexity. And even if ISO pricing worked for EGUs, it cannot be extended for any other section 111(d) source categories.

A carbon tax does not eliminate the risk, inherent in the compliance flexibility that characterizes the Clean Power Plan, that fenceline communities near dirty power plants will not benefit from the co-pollutant reductions that the proposal promises. It offers the possibility, however, that revenues could be used to finance co-pollutant reductions in those communities as described in section VII.H.3.d of these comments. We urge EPA to adopt those recommendations. Moreover, as discussed in section VII.F, EPA would need to make clear that a tax approach is not allowable for hotspot pollutants.

3. Modeling Carbon Tax for Compliance is Similar to Other SIP Modeling

A state choosing the carbon tax option will have to submit modeling that shows how the tax will produce the emissions reductions attributed to it under the state's plan. Modeling the emissions effects of regulatory measures is regularly relied on in the SIP process, and the Act specifically contemplates its use there (and throughout the Act), *e.g.*, 42 U.S.C. §§ 7410(a)(2)(K), 7412(k)(3)(D) and (G), 7475(e)(3)(D), 7491(a)(3)(B), 7502(c)(8).

Modeling the emissions effects of a carbon tax is a relatively simple two-step process, first calculating the effect of an EGU carbon tax on electricity prices, and then modeling the effect of that price increase on generation mix, electricity demand and resulting CO_2 reductions. Electricity pricing and generation demand models are ubiquitous; for example, EPA used the IPM model for estimating the costs of this rule, 79 Fed. Reg. at 34,839, and EPA specifically used the IPM model to determine the effect of a carbon price to calculate Building Block 2 of the BSER – redispatch from coal-fired to natural gas combined cycle power plants – by simulating a carbon price of $30/ton.[566]

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[565] Chang et al., The Brattle Group, *A Market-Based Regional Approach to Valuing and Reducing GHG Emissions from Power Sector* (Apr. 2014), *available at* http://www.brattle.com/system/news/pdfs/000/000/616/original/A_Market-based_Regional_Approach_to_Valuing_and_Reducing_GHG_Emissions_from_Power_Sector.pdf, at 2-4.
[566] *Abatement Measures TSD* at 3-24.

Carbon tax compliance is most easily measured using a mass-based emissions target; elsewhere in these comments, we propose a methodology for converting state goals from rate-based to mass-based.

B. The Proposed Rule Preamble Allows for a State Carbon Tax as a Means of Compliance

EPA's Preamble to the proposed rule emphasizes the flexibility that states will have in choosing the means by which they will comply with their targets:

> EPA believes that this proposal provides flexibility for states to develop plans that align with their unique circumstances, as well as their other environmental policy, energy and economic goals. All states will have the opportunity to shape their plans as they believe appropriate for meeting the proposed CO_2 goals.

79 Fed. Reg. at 34,834. The proposal provides states with latitude to employ a wide range of measures, so long as they do the job. *Id.* at 34,835. Since a carbon tax reduces emissions by putting a price on them, they are identical in this respect to "market-based emission limits" that EPA specifically describes as acceptable means of compliance, such as the RGGI and AB 32 cap and trade systems, *e.g.*,

> [The RGGI] market creates a price signal for CO_2 emissions, which factors into the dispatch of affected EGUs. A price signal for CO_2 emissions also allows sources flexibility to make emission reductions where reduction costs are lowest, and encourages innovation in developing emission control strategies.

Id. at 34,848

As EPA notes in its State Plan Considerations TSD, "the allowance market establishes a price signal for emissions (a market price for emitting a unit of pollution), which triggers broad economic incentives for reducing emissions across the covered sector(s) and encourages innovation in developing emission control strategies and new pollution control technologies."[567] A carbon tax is economically analogous to a cap-and-trade system: both encourage regulated entities to change their production processes to reduce emissions to avoid paying the emissions-based fee. By raising these costs, a carbon tax thus reduces the incentive to burn fossil fuels in exactly the same way that cap and trade does. (However, as noted above, a tax is both economically more efficient and administratively simpler than cap and trade.)

[567] *SPC TSD* at 101.

C. A Carbon Tax Meets All of the Proposed Regulatory Criteria for a State Plan

While a carbon tax may not meet the proposed definition of an "emission standard," it nevertheless meets all of the required criteria for an "emission standard." Proposed 40 C.F.R. § 60.5780(a) requires that each state plan include:

> emission standard(s) that are quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected entity. The plan shall include the methods by which each emission standard meets each of the following requirements in paragraphs (b) through (f) of this section.[568]

Subsection (b) provides that an emission standard is "quantifiable . . . if it can be reliably measured, in a manner that can be replicated." A carbon tax is the essence of a quantifiable emission standard: $X per ton of CO_2 emissions.

Subsection (c) provides that an emission standard is "verifiable with respect to an affected entity if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with the emission standard." EPA's Greenhouse Gas Reporting Rule requires continuous CO_2 emission monitoring of every affected EGU, reporting of those results, and imposes stringent recordkeeping requirements. In addition, the proposed Rule itself imposes this requirement: proposed § 60.5805(a)(2)(i) requires that "[a]n affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter."

Subsection (d) provides that an emission standard is "nonduplicative with respect to an affected entity if it is not already incorporated as an emission standard in another state plan unless incorporated in multi-state plan." No state imposes—or could impose—a carbon tax on emissions in another state.

Subsection (e) provides that an emission standard is "permanent with respect to an affected entity if the emission standard must be met for each compliance period, or unless it is replaced by another emission standard in an approved plan revision, or the state demonstrates in an approved plan revision that the emission reductions from the emission standard are no longer necessary for the state to meet its state level of performance." A state carbon tax would require the affected EGU to pay the tax until such time as it is modified or replaced by an approved plan revision.

[568] Proposed 40 C.F.R. § 60.5740(a)(6) similarly requires that a state plan contain "[a] demonstration that each emission standard is quantifiable, nonduplicative, permanent, verifiable, and enforceable with respect to an affected entity."

Finally, subsection (f) provides that an emission standard is "enforceable against an affected entity if":

> (1) A technically accurate limitation or requirement and the time period for the limitation or requirement is specified;
> (2) Compliance requirements are clearly defined;
> (3) The affected entities responsible for compliance and liable for violations can be identified;
> (4) Each compliance activity or measure is enforceable as a practical matter; and
> (5) The Administrator and the state maintain the ability to enforce violations and secure appropriate corrective actions pursuant to sections 113(a) through (h) of the Act.

A carbon tax meets each of these criteria. It is imposed on each affected EGU at a fixed rate of $X per ton of CO_2 emissions, payable at a fixed interval (presumably annually) to the state in an amount equal to the rate/ton multiplied the amount of emissions. Due to the monitoring requirements already imposed under the Reporting Rule, determining compliance could not be easier, and a carbon tax is enforceable through each of the mechanisms (administrative order, administrative penalty, civil judicial action and criminal action) described in CAA section 113.

There is no obstacle to federal government enforcement of a state carbon tax that has been incorporated into an approved SIP; federal restrictions such as the Tax Injunction Act provide only that federal courts "shall not enjoin, suspend or restrain the assessment, levy or collection of any tax under State law"; such laws have "nothing to do with complaints that federal courts are causing or allowing states to collect *too much* money in taxes." *Dunn v. Carey*, 808 F.2d 555, 558 (7th Cir. 1986) (emphasis in original).

The Act also permits citizen enforcement of a carbon tax. Citizens may sue for violation of "an emission standard or limitation under this chapter." 42 U.S.C. § 7604(a). The Act defines "[e]mission standard or limitation under this chapter" to include "any requirement under section [111] or [112] of this title (without regard to whether such requirement is expressed as an emission standard or otherwise)"; and "any other standard, limitation, or schedule established under . . . any applicable State implementation plan." *Id.* at § 7604(f)(3) and (4). Not only do the regulations deem state measures to be "emission standards", but a state EGU carbon tax could also be deemed "a requirement under section 111" or a "standard" or "limitation" established under a SIP. Because the tax itself and the emissions it would be applied to have fixed, numerical values, courts would not have the problem sometimes encountered in attempts to enforce narrative SIP requirements or goals. *See, e.g.*, *Bayview Hunters Point v. Metro. Trans. Comm'n*, 366 F.3d 692, 701 (9th Cir. 2004)(discussing "the well-established rule that courts may only enforce specific SIP strategies, and may not enforce a SIP's overall objectives or aspirational goals.")

An issue related to enforceability is what should happen in the event that the tax does not achieve the required reductions in any of the relevant periods. Specifically, EPA requested comment on:

> whether consequences should include the triggering of corrective measures in the state plan, or plan revisions to adjust requirements or add new measures. The agency also requests comment on whether corrective measures, in addition to ensuring future achievement of the state goal, should be required to achieve additional emission reductions to offset any emission performance deficiency that occurred during a performance period for the interim or final goal.

79 Fed. Reg. at 34,908.

We believe that the best way to deal with this situation in the case of a carbon tax is to have the state plan (and the underlying state legislation) provide that, in the event of such an emissions reduction shortfall, the tax rate would rise by a specific amount, with the rate increase determined by a formula based on the amount of the shortfall. This would allow for planning certainty among the affected EGUs and minimum disruption in implementing the remedial measure. As a backstop, the rules should require the plan to also include specific remedial regulatory mandates adequate to ensure achievement of the target level of reductions, such as required emissions reductions from covered EGUs, which would automatically take effect if an automatic tax increase mechanism then failed to meet the state target.

Equally important as whether the carbon tax as a regulatory mechanism is quantifiable, verifiable, non-duplicative and enforceable, is the question of whether that mechanism will result in emissions reductions that meet those criteria. The state's compliance demonstration would need to show that the state was achieving the state goal. Moreover, the automatic backstop of an even higher tax rate or regulatory mandates should the state not be in compliance should eliminate the possibility of any individual reductions being reversed.

D. Regulatory Language and a Carbon Tax

1. EPA's Proposed Revisions to Subpart B

EPA proposes requiring that each state plan include "[i]dentification of emission standards for each affected entity, compliance periods for each emission standard, and demonstration that the emission standards are, when taken together, sufficiently protective to meet the state emissions performance level." 60.5740(a)(5); 79 Fed. Reg. at 34,952.

Currently Subpart B defines "emission standard" as "a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions." 40 C.F.R.

§ 60.21(f).[569] A carbon tax does not meet this definition, and while EPA has proposed a different definition for purposes of the specific rule at issue here, a carbon tax does not appear to meet that definition either:

> *Emission standard* means in addition to the definition in § 60.21, any requirement applicable to any affected entity other than an affected source that has the effect of reducing utilization of one or more affected sources, thereby avoiding emissions from such sources, including, for example, renewable energy and demand-side energy efficiency measures requirements.

79 Fed. Reg. at 34,956. The proposed definition presents two problems. First is the introduction of a term – "affected source" – that is not defined anywhere in the statute or regulations. EPA does define "affected EGU" as "a steam generating unit, an IGCC facility, or a stationary combustion turbine that meets the applicability conditions in section § 60.5795." *Id.* The "applicability conditions" in 60.5795(b) relate to base load ratings, fuels, whether the EGU "was constructed for the purpose of supplying" certain amounts of its output to a "utility distribution system", etc. *Id.* at 34,954. EPA appears to use "affected source" to mean "affected EGU", *e.g.*, "the affected sources -- utility boilers and IGCC units as well as natural gas-fired stationary combustion turbines -- . . . ." Id. at 34,855. Note also that EPA proposes to define "affected entity" as either "an affected EGU, or another entity with obligations under this subpart for the purpose of meeting the emissions performance goal requirements in these emission guidelines." *Id.* at 34,956.

The more significant problem is the proposed definition's phrase "other than an affected source". Defining "emission standard" to broadly mean "anything that reduces emissions from affected entities" would certainly include a carbon tax, but by then carving out the EGUs – the "affected sources" – it leaves the newly-broadened definition applicable only to those non-EGU entities that have obligations under this rule. (As discussed previously, we believe that the Act requires that, as the regulated entities in this source category, the affected EGUs must be legally responsible for achieving the state targets.) In other words, as proposed this provision does not appear to include a state carbon tax on affected sources as an "emission standard".

2. Suggested Changes to Subpart B

We suggest that EPA amend its proposed regulations to allow states the option of imposing a carbon tax as part of §111(d) plans to comply with the standard of performance for carbon emissions from power plants.

[569] The clause "establishing an allowance system" was added in the CAMR rule, 70 Fed. Reg. at 28,606, 28,649 (May 18, 2005), but the CAMR Rule was vacated in its entirety by *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

EPA could accomplish such a result by deleting the phrase "other than an affected source" from the proposed definition in 60.5820, as illustrated in ~~strikethrough~~:

> *Emission standard* means in addition to the definition in § 60.21, any requirement applicable to any affected entity ~~other than an affected source~~ that has the effect of reducing utilization of one or more affected sources, thereby avoiding emissions from such sources, including, for example, renewable energy and demand-side energy efficiency measures requirements.

X. The Clean Power Plan's Impacts on Upstream Emissions from Fossil Fuel Production

EPA projects that the Clean Power Plan will increase electricity sector natural gas consumption through at least 2025.[570] The additional gas consumed during this time period will stimulate additional natural gas production, which will increase methane and other GHG emissions associated with natural gas production and transmission.[571] EPA predicts, however, that increased methane emissions from natural gas production will be outweighed by decreased methane emissions from coal production. In reaching this conclusion, however, EPA has substantially understated the amount of methane that will be emitted by this additional gas production, and thus the importance of taking action to limit these emissions. The best way to limit these emissions is to ensure that renewable energy and energy efficiency, rather than gas-fired generation, play the greatest possible role in future electricity generation. It is also essential to take strong steps to reduce methane pollution from natural gas production and transmission. Thus, to ensure that the Clean Power Plan achieves its full potential as the cornerstone of President Obama's Climate Action Plan, EPA must reduce methane emissions from the gas sector by directly regulating methane. In addition, federal action is needed to ensure that decreased electricity sector demand for coal leads to corresponding decreases in coal production, rather than a shift to coal exports, which would undermine EPA's conclusion regarding a net decrease in methane emissions.

A. The RIA Understates The Amount of Methane Emitted by Natural Gas Production.

As noted above, the RIA predicts that, in all scenarios, the Clean Power Plan will increase gas generation in 2020 and 2025, and that this additional gas generation will lead to an increase in gas production[572] and associated methane emissions.[573] The starting point for the RIA's analysis of upstream methane is EPA's Greenhouse Gas Inventory. According to this Inventory, the oil and gas sector is already the third-largest industrial source of greenhouse gas pollution, and the largest source of methane emissions.[574] In order to assess the impact of changes in

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[570] RIA at 3-47, Table 3-11 (predicting increased gas use relative to baseline in 2020 and 2025 in all scenarios).
[571] *Id.* at Table 3A-6, page 3A-9.
[572] *Id.* at Tables 3A-4 and 3A-5.
[573] *Id.* at Table 3A-6.
[574] EPA, *supra* n. 22, at Table 2-1.

production it is useful to look at the emissions per unit of gas production, rather than for the whole sector. These emissions are often expressed as a "leak rate" of methane emitted per unit of gas produced. The recent EPA Inventories imply a natural gas leak rate of roughly 1.4 percent.[575] The RIA's estimates of future gas production emissions begin with the Inventory's estimate of current emissions and then add projections for future voluntary and regulatory reductions in emissions.[576]

By using the Inventory as its starting point, the RIA almost certainly significantly understates the methane that will be emitted by increased gas production. A growing body of published, peer-reviewed research strongly indicates that methane emissions from natural gas production are significantly higher than estimated by EPA's 2013 Greenhouse Gas Inventory, which formed the basis for the RIA's discussion of this issue.[577] EPA's GHG Inventories, like the National Energy Technology Laboratory assessment, uses "bottom-up" methods. These methods estimate the average emissions from an individual piece of equipment or individual event, such as a high-bleed pneumatic device or a well completion, and multiply that per-component value by an estimate of the total number of components or events of that type.

A different method of estimating gas production methane emissions is a "top down" approach, where researchers measure the methane accumulation in the atmosphere in areas where gas production is occurring and then estimate the fraction of this methane attributable to gas production. For example, a researcher might measure methane concentrations upwind and downwind of gas activity and then subtract out the methane estimated to have been emitted from other sources. Certainty in source attribution has increased in recent years as scientists are better able to distinguish methane sources based on detected levels of co-occurring compounds such as ethane or isotopic composition of atmospheric methane.

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[575] The RIA relies on EPA's 2013 Inventory, which estimated emissions through 2011. *See* RIA at 3A-31. The 2013 Inventory implied a leak rate of 1.4 percent of gross withdrawals. Brandt *et al.*, *Methane Leaks from North American Natural Gas Systems*, 343 Science 6172 (Feb. 14, 2014), *available at* http://www.novim.org/images/pdf/ScienceSupplement.02.14.14.pdf,
Supplementary Information at 29. In April 2014, EPA released the updated 2014 Inventory cited above. The Department of Energy has determined that the 2014 Inventory also implies that that "roughly 1.4 percent of [natural gas] is vented routinely or leaked . . . throughout the natural gas supply chain." Dep't of Energy, *Fact Sheet: Natural Gas Greenhouse Gas Emissions* (July 29, 2014), *available at* http://energy.gov/sites/prod/files/2014/07/f18/20140729%20DOE%20Fact%20sheet_Natural%20Gas%20GHG%20Emissions.pdf. The National Energy Technology Laboratory ("NETL") has similarly estimated that, when looking at total domestic natural gas deliveries (including onshore and offshore production) to power plants (i.e., omitting much of the distribution sector), leaked methane equals 1.1 percent of production. NETL, *Life Cycle Analysis of Natural Gas Extraction and Power Generation*, DOE/NETL-2014/1646 (May 29, 2014) ("NETL Lifecycle Report"), *available at* http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Life%20Cycle%20Analysis/NETL-NG-Power-LCA-29May2014.pdf, at 36.
[576] RIA at 3A-1 to 3A-2, 3A-15 to 3A-30.
[577] *Id.* at 3A-31.

An early top-down study, Xiao *et al.* (2008), estimates that nationwide emissions of methane from fossil fuel sources in 2004 were 50 to 100 percent higher than bottom-up inventories estimate.[578] More recently, Miller *et al.* (2013), uses atmospheric measurements of methane in 2007 and 2008 to estimate that methane emissions from all U.S. sources were 50 percent higher than estimated for that year by the 2012 U.S. GHG Inventory. The study shows that oil and gas emissions constitute a significant portion of the observed emissions not accounted for in EPA's Inventory.[579] Atmospheric studies examining individual regions have found even higher methane emissions in the regions studied. Two studies of Colorado's Denver-Julesberg Basin have concluded that during gas production alone (not including emissions from downstream segments of the industry - transmission and distribution), the gas leak rate was about 4 percent.[580] The same team of researchers found even higher methane leak rates in Utah's Uinta Basin, estimating escaped methane at 9 ± 3 percent of total production.[581] Brandt *et al.* (2014) systematically reviews eleven top-down and a number of bottom-up studies, including the studies discussed above (with the exception of Petron *et al* (2014), which was not published at the time of Brandt *et al*'s review). Brandt *et al.* demonstrates that for many years top-down studies have very consistently shown higher emissions from oil and gas than do bottom-up studies. The authors estimate that total U.S. methane emissions from all sources were 25 to 75 percent higher than the U.S. GHG Inventory estimated for 2011, and find that oil

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[578] Xiao et al. *Global budget of ethane and regional constraints on U.S. sources*, 113 J. of Geophysical Research D21,306 (Nov. 5, 2008), *available at* http://onlinelibrary.wiley.com/doi/10.1029/2007JD009415/abstract. Xiao's result was based on a 2008 edition of the US GHG Inventory; the latest edition estimates that 2004 emissions were 17 percent higher than the 2008 edition estimated, a small difference compared to the 50-100 percent difference reported by this paper.

[579] Miller et al., *Anthropogenic emissions of methane in the United States*, 110:50 Proc. Natl. Acad. Sci. (USA) 20,018 (Oct. 18, 2013), *available at* http://www.pnas.org/content/110/50/20018. Specifically, the paper states that in moving from the 2012 Inventory to the 2013 Inventory, EPA "decreased its CH_4 emission factors for fossil fuel extraction and processing by 25 to 30 percent (for 1990–2011), but we find that CH_4 data from across North America instead indicate the need for a larger adjustment of the opposite sign." *Id.* The 2012 Inventory implied a leak rate of approximately 2.4 percent; a 25 percent increase brings the leak rate to three percent.

[580] The four percent estimate is provided by the more recent of these studies, Petron et al., A *new look at methane and non-methane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin*, 119:9 J. of Geophysical Research: Atmospheres 6836 (June 3, 2014), *abstract available at* http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/abstract. This is consistent with an earlier study, by the same lead author, which estimated using top-down techniques that 2.3 to 7.7 percent of production was vented in the studied area and concluded more generally that "the methane source from natural gas systems in Colorado is most likely underestimated by at least a factor of two." Petron et al., *Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study*, 117:D4 J. Geophys. Res. Atmospheres 4304 (Feb. 21, 2012), *abstract available at* http://onlinelibrary.wiley.com/doi/10.1029/2011JD016360/abstract.

[581] Karion et al., *Methane emissions estimate from airborne measurements over a western United States natural gas field*, 40:16 Geophysical Research Letters 4393 (Aug. 27, 2013), *abstract available at* http://onlinelibrary.wiley.com/doi/10.1002/grl.50811/abstract.

and gas are important contributors to these unreported emissions.[582] These top down studies provide compelling evidence that the aggregate methane emission estimates based on "bottom up" studies, such as the estimates used by the RIA as a starting point here, underestimate oil and gas sector methane emissions by a significant margin.

We further note that the RIA does provide quantitative information regarding the future emission reductions (voluntary and regulatory) that it assumes will be employed to reduce emissions below this starting point. As such, we do not offer comment as to the appropriateness of these assumptions.

B. Methane Emissions from Gas Systems Reinforce the Importance of Renewable Energy, Energy Efficiency, and Regulation of Methane, Whether or Not The Clean Power Plan Will Lead to Net Decreases in Methane Emissions.

While EPA predicts that the Clean Power Plan will increase gas production in 2020 and 2025, the Clean Power Plan will, of course, likely decrease coal production for domestic consumption. The RIA's predictions regarding upstream methane emissions address changes in both coal and gas production. On a per-KWh basis, upstream methane and other non-EGU-combustion emissions associated with natural gas fired electricity generation are significantly higher than the corresponding emissions from coal fired generation.[583] The RIA predicts that in all Clean Power Plan scenarios, however, the decrease in coal generation will be greater than any increase in natural gas generation.[584] On this basis, the RIA predicts that decreases in methane from coal production will exceed increase in methane from gas production in 2020 and 2025.[585] For the reasons stated above, we believe the RIA significantly understates methane emissions from natural gas systems.

While it may be the case that, under the production levels predicted by the RIA, the Clean Power Plan will reduce net methane emissions below EIA projected levels in 2025 and beyond, a reduction in coal mining methane emissions does not change the fact that methane emissions from natural gas systems are a significant contributor to climate change that EPA must address. Even if, as the RIA predicts, the Clean Power Plan will uniformly result in net decreases in methane emissions, methane from natural gas systems is another source of emissions, and thus a source of potential emission reductions, that cannot be ignored.

The most effective and important way to limit the emissions from natural gas systems is to limit reliance on natural gas by utilizing renewable energy and energy efficiency as fully as possible. Isolated comparison of coal and gas power plant emission rates, and thereby ignoring

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[582] Brandt, *supra* n. 575, at 733.

[583] *Id.* at Fig. 4-13. This table compares upstream emissions on a heat content, rather than KWh, basis, and therefore does not reflect the greater thermal efficiency of natural gas fired generation.

[584] RIA at Table 3-11.

[585] RIA at Tables 3A-6 and 3A-7. In 2030 under Option 1, both coal production and gas production decrease relative to the base case.

the full fuel life cycle, significantly overstates the climate benefit of switching from coal to gas. This is doubly true when one considers the recent peer reviewed science indicating that EPA significantly underestimates both the tonnage of methane emitted per unit of gas production and the climate impact of each ton of methane. As we explained above, numerous top down and other studies indicate that actual methane emissions from natural gas systems are much higher than estimated by EPA's GHG inventories. This error is compounded by the RIA's use of an outdated methane global warming potential of 25 on a 100-year timescale.[586] This estimate is taken from the Intergovernmental Panel on Climate Change's Fourth Assessment Report. The more recent Fifth Assessment Report, released in pertinent part in September 2013, estimates that that on the 100-year time scale, a ton of fossil methane has a climate impact 36 times greater than a ton of carbon dioxide.[587] On a twenty year timescale, the IPCC now estimates that a ton of fossil methane emissions has 87 times the impact of a ton of carbon dioxide. Because gas fired electricity generation emits more tons of methane per KWh than coal fired generation, adopting a higher methane global warming potential further erodes gas's climate advantage over coal. As zero-emitting resources, EE and RE have a tremendous advantage over *all* fossil fuels—including natural gas—from a climate perspective.

Second, to the extent that natural gas is used, EPA must regulate methane emissions from gas systems to reduce these lifecycle impacts.[588] If, as the RIA predicts, the Clean Power Plan increases gas use and production in 2020 and 2025, this will increase the need for prompt direct regulation of methane. The fact that the RIA predicts a decrease in gas use under Option 1 in 2030 does not limit the need for methane regulation. Despite the net decrease, the RIA predicts continuing wide use of natural gas in the electricity sector in 2030. Moreover, because methane is such a potent greenhouse gas, the increase in emissions in the earlier years of the plan will have a significant climate impact.

C. The Projected Decreases in Coal Mining Methane Emissions Will Not Occur if Coal Exports Substitute for Decreased Electricity Sector Coal Demand.

EPA acknowledges that, absent further action, increased coal exports may offset the decrease in electricity sector coal consumption, limiting the net decrease in coal production and associated methane emissions.[589] EPA has not, however, included this possibility in its modeling or other discussion. In finalizing its regulatory analysis, EPA should at the very least attempt to address whether U.S. coal producers would be able to secure international buyers on the coal export market to make up for part or all of the reduced domestic demand. Given that industry continues to pursue new coal export terminals (as well as increased capacity through existing ports) in California, Louisiana, and Oregon, among other places, it seems very likely that any

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[586] RIA at 3A-5, 3A-9, 3A-10.
[587] IPCC, *supra* n. 2, at 714, Table 8.7.
[588] Cost-effective methods of reducing methane emissions from oil and gas extraction are discussed in McCabe et al., Clean Air Task Force, *Waste Not: Common sense ways to reduce methane pollution from the oil and natural gas industry* (Nov. 2014), summary report attached as **Ex. 64**.
[589] RIA at 3A-10.

reduction in U.S. coal consumption as a result of EPA's rulemaking would be offset somewhat by an increase in coal exports. Since that offset would affect the amount of coal produced and the amount of methane emitted from U.S. coal mines, EPA ought to take a serious look at all relevant market forces rather than merely qualify its findings under an "uncertainties and limitations" disclosure.

In addition, the Administration must consider efforts to limit the potential for coal exports to undercut the emission reductions that would otherwise be achieved by the Clean Power Plan. For example, as the Clean Power Plan decreases domestic coal demand, the Bureau of Land Management could decrease coal leasing on federal lands to commensurately decrease supply.

XI. Reliability

As the power grid transitions to a cleaner and more sustainable future, several groups have raised concerns over the number of projected retirements of covered units the new GHG standards may necessitate, and how such retirements would affect the “reliability” of the power grid. The concern that the Clean Power Plan will undermine the ability of utilities and regional grid operators to reliably provide electricity to consumers is unfounded. Each time EPA undertakes rulemakings affecting the electric generating sector, naysayers cry that the lights will go out, yet each of EPA’s actions to reduce pollution from these sources results in a cleaner environment and an intact electric grid.

The Clean Power Plan is no exception. The cooperative federalism model that forms the basis of the CPP allows states to design their plans to minimize disruptive impacts on the grid. We are therefore confident that states working in conjunction with regional grid operators will be able to ensure a smooth transition to a cleaner and more efficient power grid over the next five to fifteen years.

In particular, we oppose two specific policy recommendations made by utilities and operators: first, to delay implementation of the CPP, which would further delay our necessary transition to new and cleaner power sources; and second, to include a “reliability safety valve,” which would in effect reward the utilities and affected EGUs who drag their feet and allow them to continue emitting large amounts of greenhouse gases. However, we join with these grid operators and other commenters in calling on EPA to encourage advanced planning for anticipated supply shifts, and especially to facilitate cooperation between states and regional and local grid operators when implementing the CPP.

A. Identified Reliability Needs and Solutions

When energy experts refer to maintaining the “reliability” of the grid, they generally are grouping together multiple attributes of the energy distribution system required to keep electricity flow stable and predictable. These attributes can be split roughly into three different types of “reliability”: 1) overall resource adequacy, 2) voltage and frequency stability, and 3) resilience against large system shocks. Certain regional grid operators have raised particular concerns about the ability of a restructured energy system to provide each of these types of reliability.

In this section, we identify the perceived challenge, provide our evaluation of its severity, and lay out solutions to the challenge. The conclusion reached throughout this section is that, although grid operators have come to rely on large traditional power providers to keep power flowing to consumers, with proper advanced planning they have a plethora of solutions available to them to meet those needs that don't require continued reliance on high-emitting power plants.

1. Resource Adequacy

Resource adequacy refers to the presence (or absence) of sufficient electricity supply (including "negawatts" from efficiency and demand response) to meet the anticipated electricity demand in the course of a typical day. This reliability attribute ultimately rests on bulk power capacity, and the ability of that capacity to predictably produce electricity.

The primary basis for the concerns raised about over overall system capacity is the rate of anticipated retirements of coal-burning power plants. EPA has calculated that implementation of the CPP could lead to retirement of an additional 50 GW of coal-based electricity production over the base case by 2025.[590] According to EPA's BSER formula, lost generation will be replaced through a combination of capacity factor increases at gas facilities, increased generation from renewable energy resources, and demand-side energy efficiency. Renewable generation and efficiency improvements would also replace lost capacity, along with increased electricity storage and demand response, as discussed further below.

One of the broadest critiques of EPA's overall calculations has come from NERC, in its Initial Reliability Review.[591] In particular, NERC questions the viability of EPA's proposed renewable energy, transmission, and energy efficiency build-out goals. These critiques paint a needlessly pessimistic view of what is achievable, and run contrary to several studies demonstrating the potential for renewable energy and energy efficiency to replace existing generation.

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[590] Some commenters have suggested that the EPA's expected heat-rate improvements are infeasible, and that therefore more coal-burning power plants will need to retire than EPA anticipates. As noted elsewhere in these comments, we believe a 9 to 10 percent heat rate improvement requirement is justified, but even if certain states or plants cannot meet the 6 percent rate, the flexibility inherent to the CPP process will allow them to achieve extra emission reductions elsewhere.
[591] NERC, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan* (Nov. 2014) [hereinafter *NERC Reliability Review*].

a. Potential for Renewable Generation Build-out

One of NERC's two main arguments challenging EPA's expectations for build-out of renewable power facilities is that EPA's renewable portfolio standard (RPS)-based formula overestimates states' ability to build renewable generation.[592] While NERC is correct that the use of existing RPSs to establish renewables obligations does not perfectly correspond to states' actual capacity to install wind and solar plants, we believe it *understates* the potential for renewable generation build-out, thus artificially lowering states' renewables obligations. In fact, EPA's RPS-based Building Block 3 target barely exceeds the "business as usual" forecasts for renewable energy development by 2030.[593] Thus, EPA's target is not pushing states toward an unprecedented level of renewable energy development, but rather toward the level of renewable energy generation that grid operators should already be forecasting and planning for. 29 states (including the District of Columbia) have passed mandatory RPS goals, and another 7 states have voluntary goals. One study looking at states' compliance with their own goals found that 21 of 24 states for which data was available had virtually achieved or exceeded their intermediate RPS goals. [594] (A few states have even exceeded their ultimate RPS goals.[595])

Critically, states have historically found it easier to comply with RPS goals over time as they develop in-state markets and build local expertise in siting and connecting renewable electricity.[596] This trend should only continue as renewable energy becomes more and more affordable: in 2013, average prices for utility-scale wind and solar power purchase agreements dropped to all-time lows of $21 and $50 per megawatt-hour respectively, compared to average whole sale power prices of between $22 and $55 overall.[597] Similarly, the Energy Information Administration's estimate of the total levelized cost of energy by resource, including installation and other costs, predicts that wind will be over $15 cheaper than coal per MWh by 2019, and $8 cheaper than conventional natural gas by 2040. [598] A projection done by Lazard Ltd., a financial advisory and asset management firm, has concluded that already today wind energy is at least cost-competitive with, if not cheaper than, both natural gas and coal facilities, with solar not far behind (within $10/MWh of both gas and coal).[599] The consensus expectation in all

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[592] *Id.* at 11-12.
[593] *See* UCS, *supra* n. 183.
[594] Leon, W., Clean Energy States Alliance, *The State of State Renewable Portfolio Standards* (June 2013), attached as **Ex. 65**; Barbose, G., LBNL, *Renewables Portfolio Standards in the United States: A Status Update* (Dec. 3, 2012), at 24.
[595] Climate Central*, Interactive Map Compares States' Renewable Energy Goals*, http://www.climatecentral.org/blogs/interactive-map-to-compare-states-renewable-energy-goals (last visited Nov. 24, 2014).
[596] Leon, *supra* n. 594, at 6-7.
[597] DOE, *supra* n. 194; Bolinger & Weaver, LBNL, *Utility-Scale Solar 2013: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (Sep. 2014), attached as **Ex. 66**, at 28.
[598] EIA, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014* (Apr. 17, 2014) [hereinafter *EIA Outlook*], available at http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.
[599] Lazard, *supra* n. 172, at 2.

of these reports is that renewable energy prices will continue to drop as renewable technologies continue to be mainstreamed.[600] In short, the market for renewable energy has surged in a way that was not fully anticipated when states set their RPS goals, so they are no longer an accurate reflection of what can be accomplished in individual states.

Even ignoring the growing strength and competitiveness of the renewable generation market, EPA should not be overly concerned about replacing retiring coal plants because regions with excess (largely cleaner) electricity production will likely end up transmitting that electricity to regions that find themselves less able to replace retiring dirty power plants (see transmission discussion below). Moreover, no state is required to achieve the level of renewable energy development that EPA used in setting its target—states have flexibility to use a combination of any of the building blocks as compliance measures. EPA is also not requiring renewable energy to be built within a state for that state to take credit under the Clean Power Plan. This means that renewable energy can be built wherever it is most economic and there is available transmission capacity.

b. Potential for Transmission Capacity Improvements

NERC, and other grid operators analyzing the impacts of EPA's proposal, have recognized the importance of transmission, and acknowledge that increased transmission capacity will help the grid transition to renewable energy. But they also dismiss transmission planning as an excessively long-term solution, arguing that it takes too long to fully install new planned transmission lines.[601] NERC in particular uses an assumed 10-15 year timetable to justify its calls to delay implementation of the CPP, arguing further that regional grid operators cannot even begin to plan transmission until state plans are approved under the CPP, which would give them less than two years to build out the necessary transmission.[602]

NERC's use of this supposed transmission "bottleneck" is inapposite for several reasons. First, transmission lines simply don't take 10-15 years to build on a regular basis. Although some lines may take that long, especially when tricky siting issues are involved, there is no reason it should take that long for most lines; indeed, ERCOT in its analysis of the CPP notes that major transmission projects can be planned, routed, approved and constructed in five years.[603] ERCOT's conclusion is more consistent with practice: to pick one example, Prairie Wind Transmission, LLC, a 108-mile high voltage cable connecting wind resources in Oklahoma and Kansas to load centers elsewhere within SPP, was conceived in 2008, permitted in 2011, and as of June 2014 has been put mostly online (with the remaining 30 miles expected to go online by

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[600] *Id.* at 9-10; *see also EIA Outlook*, *supra* n. 598.
[601] *NERC Reliability Review*, *supra* n. 591, at 20.
[602] *Id.*
[603] *ERCOT Reliability Review*, supra n. 273.

the end of the year).[604] Furthermore, the process of building out transmission to transport renewable energy to load centers has already begun in recent years, and will ramp up significantly if grid operators take appropriate steps to prepare for CPP implementation. Multiple RTOs are considering transmission improvements already,[605] and in particular, Clean Line Energy Partners is currently working to construct five major transmission lines to move 15.5 GW of largely wind-sourced electricity in the middle of the country out to load centers in the Midwest, Southwest, and on the West Coast.[606]

Another major point undermining the severity of NERC's transmission concerns is that it misstates the timeline on which transmission projects could be planned, and would be needed.[607] To begin with, there is no reason why states and grid operators need to wait until plans are approved to begin studying what transmission upgrades may be needed. Grid operators' mandates include an obligation to assess and respond to policy developments and how they will affect the need for generation and transmission[608]; forthcoming regulatory obligations such as the CPP therefore give rise to their duty to begin planning for future transmission needs despite some degree of uncertainty about some details in state plans. On the other end, although more transmission will certainly be needed in the future, the CPP's compliance schedule contemplates a slow ramping of stringency, and transmission improvements are generally considered to be a mid- to long-term need, rather than an immediate one. Several regions (especially California) have already incorporated high levels of renewables without requiring significant transmission infrastructural changes (see discussion below).

Finally, NERC overlooks numerous alternatives to new transmission projects that also could resolve its predicted transmission constraints. Such measures include adding lines to existing transmission corridors, reconductoring, or otherwise upgrading existing facilities. These types of projects take far less time, both for regulatory approval and construction, and require no siting process. They are also less expensive than building entirely new transmission lines. Furthermore, transmission system planners are required to consider non-transmission

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[604] Press Release, Westar Energy, Inc., *Prairie Wind Transmission, LLC: New Transmission 'Super Highway' Connects West, East Kansas and Improves Reliability* (June 5, 2014), *available at* http://inpublic.globenewswire.com/releaseDetails.faces?rId=1791122.

[605] MISO, *Transmission Expansion Plan* (2013), *available at* https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx (last visited Nov. 25, 2014); *ERCOT Reliability Review*, *supra* n. 273, at 14-15.

[606] Clean Line Energy Partners, *Projects Summary*, http://www.cleanlineenergy.com/projects (last visited Nov. 24, 2014).

[607] Tierney, S., Analysis Group, *Greenhouse Gas Emission Reductions from Existing Power Plants: Options to Ensure Electric System Reliability* (May 2014).

[608] Fed. Energy Reg. Comm'n ("FERC"), *Order No, 1000: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 76 Fed. Reg. 49,842 (Aug. 11, 2011).

alternatives to new wires projects,[609] such as demand-side management. These projects can be implemented more quickly and at lower cost than new transmission.

NERC's evaluation also fails to reflect how energy efficiency will lessen the need for new transmission infrastructure in general, or how states could design targeted demand-side management programs to resolve areas of congestion.

c. Potential for Efficiency Improvements

NERC similarly critiques EPA's assessment of the potential for energy efficiency improvements, particularly casting doubt on the potential for industrial and commercial customers to realize future efficiency gains, and on the long-term sustainability of efficiency improvements.[610] The premise for NERC's contention that industrial and commercial customers will not be able to achieve the same level of cheap savings as residential customers is that companies, and particular industrial users, already "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."[611] There is an apparent logic to this assertion, because we expect companies to maximize their own self-interest, but it has been proven wrong many times. New technologies and changing cost parameters mean that new energy efficiency opportunities arise continually for commercial and industrial sectors. Similarly, innovative financing structures are emerging to improve payback and internal rates of return. Many states have run industrial and commercial energy efficiency programs for years that continue to produce significant cost effective savings. Finally, the attractiveness of an investment in energy efficiency by commercial and industrial facility owners will increase if these entities stand to gain revenue under the CPP for energy efficiency credits that can be sold to owners of power plants for compliance.

NERC's argument is based on a misunderstanding of the difference between industrial firm economics and utility system economics. For a variety of reasons, including ignorance, split incentives, and financial limitations, commercial and industrial customers will typically pursue only energy efficiency investments with a short, typically less than two-year, payback period.[612] In contrast, a utility seeking to procure the lowest-cost resource over the next decade will find it advantageous to incentivize measures with longer payback periods that otherwise would not be implemented. Also, what is a cost-effective measure from an individual consumer's perspective does not correspond perfectly to what is cost-effective from a system-wide

[609] FERC, *Order No. 890: Preventing Undue Discrimination and Preference in Transmission Service*, 72 Fed. Reg. 12,266 (March 15, 2007).
[610] *NERC Reliability Review*, supra n. 591, at 14-16.
[611] *Id.* at 15
[612] Kwatra & Essig, ACEEE, *The Promise and Potential of Comprehensive Commercial Building Retrofit Programs*, Report No. A1402 (May 2014), at 8-10.

perspective—thus there are untapped energy efficiency opportunities in the industrial and commercial sector. [613]

The high potential for efficiency gains in industrial and commercial users was confirmed recently in a study analyzing a wide range of programs, in 31 states, from 2009 to 2011. That study found that commercial and industrial participants in efficiency programs achieved efficiency improvements at a levelized cost of about $21 per megawatt hour, only $3 more than that achieved in residential programs.[614] Commercial and industrial users also achieved significantly more efficiency gains overall than residential users did from their programs: commercial programs spent $3.2 billion, more than double the $1.5 billion spent on residential programs, to achieve double the lifetime gross efficiency savings.[615]

NERC also claims that the world of efficiency gains is so finite that 1.5 percent gains in demand-side management cannot be sustained annually until 2030. First, it should be noted that few states—aside from those that already have ambitious energy efficiency targets—will be expected to sustain 1.5 percent annual savings over the full interim period.[616] On average, states are not expected to attain the 1.5 percent annual savings rate until 2025. Second, high levels of savings have been sustained around the country. EPA notes the long-record of high savings in the Pacific Northwest,[617] and California's history of efficiency improvements alone belies NERC's claim. Until about 1975, California's per-person megawatt-hour use tracked national usage almost exactly. Since the 1970's, California's energy use per person has virtually flat-lined, at least partially because California in 1977 took the lead in improving building and appliance efficiency to improve the productivity of its electricity usage.[618] In spite of this leadership, and the significant efficiency gains it has already achieved, California continues to invest significantly in energy efficiency, and has projected up to 50 percent additional energy savings for existing homes and commercial structures by 2030.[619]

Finally, states are not required to sustain this level of savings for any particular period of time, or to achieve it at all; NERC's argument mistakes EPA's target setting with compliance requirements.

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[613] Nadel & Herndon, *The Future of the Utility Industry and the Role of Energy Efficiency* (June 2014), *available for download at* http://www.aceee.org/research-report/u1404, at 66-69.
[614] Billingsley, at al., LNBL, *The Program Administrator Cost of Saved Energy for Utility Customer-Funded energy Efficiency Programs* (Mar. 2014), attached as **Ex. 67**, at 28.
[615] *Id.* at 20.
[616] *Abatement Measures TSD* at Appendix 5-4, Sheet "Opt 1 – Incr Savings %."
[617] *Id.* at 5-10.
[618] Alliance Comm'n on Nat'l Energy Efficiency Policy, *The History of Energy Efficiency* (Jan. 2013), attached as **Ex. 68**, at 20.
[619] *Id.*

d. Flexibilities in the CPP

None of the above arguments are meant to imply that *every* state will meet EPA's renewable energy build-out goals, or that every state has the same potential for sustained energy efficiency improvements. Different states will have different paths to compliance depending on the existing resource mix in their state, potential for renewable energy, level of energy savings already achieved, and various other factors. This is the main benefit of the CPP's cooperative federalism approach: different approaches will make sense for different regions, and states are not required to achieve each of the building blocks to ensure compliance with their obligations. In sum, by focusing so heavily on EPA's building blocks and identifying individual situations where certain of those blocks may be difficult to achieve, NERC artificially compartmentalizes the compliance process, making states' paths to compliance seem more daunting than they actually are.

e. Region-Specific Analyses

NERC is not the only entity that has addressed the reliability implications of EPA's projected coal plant retirements. In addition to NERC, analyses of the CPP's impacts on reliability have been released by The Southwest Power Pool ("SPP"), an RTO operating in Texas, New Mexico, Oklahoma, Arkansas, Kansas, Missouri, and Louisiana; the Electric Reliability Council of Texas ("ERCOT"), an ISO operating entirely within Texas; PJM Interconnection LLC ("PJM"), which serves all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia; and the Midcontinent ISO ("MISO"), which serves all or part of Minnesota, Wisconsin, Michigan, Ohio, Indiana, Illinois, Missouri, Kentucky, Pennsylvania, North and South Dakota, Montana, Nebraska, and the Canadian province of Manitoba.

i. SPP

SPP has been one of the most vocal grid operators in voicing concerns with the CPP. Its October 2014 Reliability Impact Assessment assessed the implications of every anticipated coal plant retirement in the SPP region, and concluded that those losses, offset by currently planned or existing wind and natural gas resources, would shrink the region's "reserve margin" (the percent by which generating capacity exceeds expected demand) from 13.6 to 4.7 percent by 2020, and to -4.0 percent in 2024.[620] Based on these findings, SPP's comments ask EPA to put off any compliance with the CPP to 2025, and adopt the "reliability safety valve" proposed by the ISO/RTO Council (see discussion below).[621]

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[620] Southwest Power Pool ("SPP"), *SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan* 6 [hereafter, "*SPP Reliability Review*"] (Oct. 2014) at 5.
[621] *Letter from Nicholas A. Brown, Southwest Power Pool, Inc., to Gina McCarthy, EPA Administrator* (Oct. 9, 2014) [hereafter, "*SPP Letter*"] at 10.

SPP's conclusion that a resource adequacy crisis would ensue are to be expected given the analysis it performed: it assumed that almost 15 percent of the region's power supply would retire without replacing it with any new power sources or demand-side management and unsurprisingly, found that reliability would suffer. Those conclusions are not, however, based in the reality of what CPP is expected to accomplish or how resource planning unfolds: the CPP objectives will be reached only if states invest in renewable resources, demand-side management strategies, and other new, low-carbon emitting generation. Nothing in the rule requires that any of the coal-burning capacity in SPP retire, much less prior to other generation coming online. We also note that SPP is well-positioned to transition under the Clean Power Plan, given that it achieved a reserve margin of 47 percent in 2013 and has not had a margin below 32 percent in the last six years at least (both numbers are far above its 13.6 percent requirement),[622] and that it is located in the heart of our nation's strongest potential regions for wind power production. Assuming the SPP and its member states plan for the transition, it should have no difficulties ensuring resource adequacy.

ii. ERCOT

ERCOT has, like SPP, raised significant concerns relating to the impact the CPP will have on grid reliability, and it has supported both the delay and the safety valve proposals put forth by industry groups (see discussion below).[623] ERCOT's critique has less to do with overall resource adequacy, however, instead focusing on voltage and frequency stability concerns that we address in the next section.[624] Its model predicts retirement of between 5.7 and 7.8 GW of electricity generation capacity between now and 2029 under the CPP (compared to a baseline of 2.8 GW of retirements), and addition of 16.9 to 19.3 GW of new generation, about 90 percent from wind and solar alone (compared to baseline of 14.5 GW of new generation, about two-thirds from wind and solar).[625] In other words, ERCOT's modeling anticipates the net loss of between 0.2 and 1 GW of capacity resulting from the CPP, and a dramatic shift in resources from coal to renewables.

ERCOT's model does predict a capacity constraint sometime between 2018 and 2022, when coal plants are trying to retire and renewables have not yet been fully built out; but this should not be a major concern.[626] ERCOT's concerns are unfounded because the CPP provides enough flexibility that, if necessary, coal plants can continue operating early in the compliance period. ERCOT also has a number of tools available to respond to projected shortfalls. It can and should supplement already-planned major transmission line improvements with additional projects serving load centers in the state, and as a last-resort (as ERCOT acknowledges), it can keep coal plants operating using reliability-must-run contracts to cover identified shortfalls, or shift generation from existing coal to gas units.

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[622] SPP, *2013 State of the Market* (May 2014), at 16-17.
[623] *ERCOT Reliability Review*, *supra* n. 273, at 2.
[624] *Id.* at 9-14.
[625] *Id.* at 6
[626] *Id.* at 6.

Furthermore, although ERCOT does actually predict significant levels of new renewable generation (unlike SPP's analysis, which ignored renewables entirely), there are still several flaws in its modeling assumptions that undermine its overall analysis. Most pointedly, ERCOT assumed, without any apparent basis for this assumption, that Texas would enact a flat price on greenhouse gas emissions to meet its obligations under the CPP.[627] Meanwhile, the third scenario applied CPP limits in the most cost-effective way possible, supposedly to determine the ideal compliance option, but that study requires ERCOT to meet the applicable emission rate goal every year, thereby failing to take advantage of the 2020-2029 compliance averaging, which is one of the CPP's key flexibility mechanisms.[628] ERCOT also dismisses that scenario as unrealistic because it may not be achievable "within the current electricity market design in ERCOT."[629] This may be true, but there is no requirement that the current market design remain in place: ERCOT can clearly redesign its market to accommodate faster market changes, and in fact already is looking into redesigning its ancillary services market to accommodate distributed generation (and demand response resources).[630] ERCOT also assumes efficiency gains of just over half EPA's projections by relying on historical trends instead of considering future potential; and it assumes the current Production Tax Credit (which has incentivized huge wind build-out in the state) will expire with no replacement, even though that would be an easy way to continue the current rate of wind generation construction. And finally, ERCOT's model does not include any "negawatts" for demand response services, which could be a huge contributor to the reliability of Texas's power grid.[631] These incorrect baseline assumptions undermine the utility of ERCOT's model in predicting future reliability needs.

iii. PJM/MISO

Neither PJM nor MISO has released a comprehensive analysis of the CPP's impacts on grid reliability, but they have both released results from models they set up to determine the impacts of the CPP. Both models indicate that creation of regional compliance plans, rather than leaving states to achieve individual compliance, could achieve the required reductions at a significantly lower cost.[632] We concur with both RTOs that regional compliance represents a more flexible compliance pathway for individual states, which would further reduce any

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[627] *Id.* at 2-3.
[628] *Id.* at 5.
[629] *Id.* at 2.
[630] ERCOT, *667NPRR-01 Ancillary Service Redesign 111814* (11/18/2014).
[631] *ERCOT Reliability Review*, *supra* n. 273, at 3-5.
[632] Midcontinent Independent System Operator ("MISO"), *GHG Regulation Impact Analysis—Initial Study Results* [hereafter, "*MISO Reliability Review*"] (Sep. 17, 2014) at 11 (noting that regional compliance options would save $3 billion annually as compared with state-specific plans); Sotkiewicz & Abdur-Rahman, PJM Interconnection, Inc., *EPA's Clean Power Plan Proposal Review of PJM Analyses Preliminary Results* [hereafter, "*PJM Reliability Review*"] (Nov. 2014) at 35-37 (modeling almost $10 billion in savings for the year 2020 for a regional compliance plan over state-specific plans).

reliability concerns in the region. MISO also concludes that utilization of non-building block compliance options would significantly reduce compliance costs.[633]

There is little to respond to in either RTO's releases to-date from a reliability perspective, but we do also note that the PJM model concludes that already-planned coal plant retirements will reduce greenhouse gas emissions by a significant amount already, making compliance with early CPP goals even less daunting. In particular, PJM apparently believes that six states (Ohio, Pennsylvania, New Jersey, Kentucky, Virginia, and Maryland) will meet their 2020 interim targets *simply by following through on planned coal retirements in their states*.[634] We disagree with this analysis because we believe PJM used a higher mass cap on emissions than will be allowed under the CPP, but the analysis nonetheless demonstrates, at least in the PJM region, that the CPP will not impose any insurmountable burden on those states' power grids, and belies PJM's contention in public forums that policy protections are needed to ensure grid reliability.[635]

2. Voltage and Frequency Stability

Another reliability issue raised by several commenters is how the shift away from large central-station generation will affect voltage and frequency stability on the system. Voltage and frequency stability services are two major categories of "Essential Reliability Services" (ERSs) provided to grid operators that are valued above and beyond the power capacity generating sources can provide. Historically, ERSs have largely been provided by traditional power plants (especially coal-burning power plants) because, as explained below, large-scale plants are particularly well suited to providing these services. As a result, grid operators have raised the prospect of reduced ERSs in the system as a second, distinct reason to oppose regulations that would result in significant coal plant retirements. NERC and ERCOT in particular have chosen to tackle this issue head-on in their critiques of the CPP, arguing that added wind and solar resources on the grid will put a premium on ERSs in a way grids currently are not prepared to manage.[636]

These services are important, but these initial reliability reports overstate the severity of this problem and undervalue the potential for renewables to provide ERSs with proper planning. Several studies, including a concept paper prepared by NERC's own ERS Task Force, have found that properly sited and connected renewable energy services are well prepared to take on retiring coal plants' contributions to the burden of stabilizing the power grid. (Natural gas plants also provide ERSs.) The next few paragraphs lay out the major types of voltage and frequency stability services, how they are currently provided, and how renewables and other system solutions can continue to provide them in the future.

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[633] *MISO Reliability Review*, *supra* n. 632, at 3.
[634] *PJM Reliability Review*, *supra* n. 632, at 17-18.
[635] Heidorn, R., *State Officials Challenge EPA Assumptions on Carbon Rule*, RTO Insider (Oct. 20, 2014); *see* discussion below for our response to grid operators' policy recommendations.
[636] *NERC Reliability Review*, supra n. 591, at 25-26; *ERCOT Reliability Review*, supra n. 273, at 10-11.

a. Voltage Services

Voltage services, as their name suggests, help keep the voltage of the power grid stable over its entire network. Because voltage varies quickly over distances, voltage service providers largely act locally, and must be distributed throughout the power system. In practice, voltage support mostly comes down to the grid's ability to balance "real" power (the usable power on the grid) with "reactive" power (the unusable power on the grid, also called phantom power). Collectively, reactive power and real power make up the total power on a given line, so a rise in one necessarily leads to a drop in another. As a result, if there is too much reactive power on the grid, end-use equipment absorbs too much reactive power with its real power, and can overheat before receiving enough real power to operate. If there is not enough reactive power on the grid, the real power voltage will surge, overcoming equipment insulation and damaging their machinery. As such, reactive support providers must have the capacity to add *or remove* reactive power from the system.

Traditionally, large generators attached to large single power plants have provided this service by releasing more or less reactive power as needed. This forms the basis for both NERC's and ERCOT's assertions that the loss of significant coal resources will place a premium on these services.[637] These claims are unfounded: NERC's ERS Task Force has noted that generators attached to wind or solar plants also can provide both real and reactive power, and inverters attached to those generators can do so even when the plants are not producing any electricity.[638] In addition, energy storage services can also provide voltage stability services, and they already do so in several parts of the country.[639] (Power storage systems generally have a critical role to play in preserving the stability of the grid, and their expansion in recent years is an important development EPA and states should look to harness to help incorporate our shifting power supply.)

b. Frequency Services

Frequency services are primarily focused on maintaining the system at the standard frequency (in the United States, this is 60 Hertz, or power cycles/second). There are several types of frequency services, covering different time frames of need (seconds, hours, days, etc.). Looking first at day-to-day reliability needs, i.e., excluding periods when there are major disturbances to the grid, these services can be roughly divided into small-scale immediate balancing, and longer-term daily load management.

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[637] *NERC Reliability Review*, supra n. 591, at 25; *ERCOT Reliability Review*, supra n. 273, at 10.

[638] NERC, Essential Reliability Services Task Force, *A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability* [hereafter, "*ERSTF Concept Paper*"] (Oct. 2014), attached as **Ex. 69**, at 11-12, n. 10.

[639] *See, e.g.*, The Brattle Group, *The Value of Distributed Electricity Storage in Texas* (Nov. 2014), attached as **Ex. 70**; EPRI, *Cost-Effectiveness of Energy Storage in California* (June 2013), attached as **Ex. 71**.

Balancing support services smooth the numerous second-to-second fluctuations that occur throughout the day. One way small changes are balanced is through possession of high inertia, which is simply the inherent resistance of certain generators to frequency changes (i.e. generators with high inertia resist changes in the power cycle speed (Hertz) in either direction). Coal-burning power plants have massive generators, so they have traditionally provided significant inertial support on the system. Utility-scale wind and solar plants historically have not provided this because they use DC generators that don't connect directly to the grid, but they can provide "synthetic" inertia when their DC generators are connected to AC inverters, allowing them to connect directly.[640]

The other main way ERS providers help balance second-to-second fluctuations in the system is through quick jumps and drops in power provided to the grid. This requires that power sources be equipped with electronic "governors" (this type of support is also called governor response) that allow a central operator to spike or drop power supply from the generator in a matter of seconds. As with inertial support, renewable sources have not historically been major providers of governor response, but when properly connected to the grid it is relatively easy for them to do so, especially in the downward direction (it is possible for renewables also to provide upward governor responses, but only if their total power output is curtailed.)[641] Thus, between this and the possibility for synthetic inertia, there is no reason to believe that it will be impossible, or even prohibitively difficult, to maintain balancing support services as the grid shifts over time.

Daily load management requires that grid operators be able to increase or decrease power provision to balance frequency to correspond to longer-term fluctuations (both anticipated and unanticipated) in electricity demand over the course of a day. These reliability services are provided both by back-up generation facilities ("operating reserves") and by active generating facilities capable of ramping power supply up or down for minutes or hours at a time. Operating reserves are classified depending on how quickly they can come online and how long they can last,[642] and are typically provided by natural gas and other quick-starting and resource-limited controlled power facilities. Because wind and solar plants constantly harness available natural resources, they are not well-suited to provide operating reserves; instead, they are expected to replace power generators that run most or all of the time, and which provide extensive ramping services to the grid.

Perhaps the most pervasive critique of renewable energy resources from a reliability perspective is that they are unsuited for providing ramping services because their output is constrained by meteorology. This critique forms much of the basis for the "reliability concerns"

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[640] *ERSTF Concept Paper*, *supra* n. 638, at 8-9.
[641] *Id.* at 6.
[642] In order from the quickest and shortest-lasting, to the slowest and longest lasting, these "operating reserves" are called regulation reserve, spinning reserve, load-following reserve, non-spinning reserve, and replacement or supplemental reserve. *Id.* at 3.

raised by opponents of the CPP and a shifting energy supply.[643] It is also needlessly pessimistic. Wind power plants in particular, but also large-scale solar installations, are already required to have the capability to provide ramping services as required.[644] In fact, NERC's own reliability task force noted in its summary that "[s]ome modern utility-scale [renewable energy plants] have greater ramp control capability for control [sic] than coal-fired conventional generators (up or down)."[645] This is not to say, of course, that it will necessarily be good policy to ask too much ramping from utility-scale renewable generators, because doing so normally requires curtailing their power output (which reduces their overall capacity factors); but finding the right balance is part of the challenge to which EPA rightly expects states and grid operators can and will respond.

For both of the above types of frequency control services, it also bears mentioning that electricity storage facilities can be as effective at controlling frequency as they can controlling voltage on the grid. Furthermore, none of the critiques mention the huge potential of demand response services, recognized by NERC's own ERS Task Force,[646] which are already heavily utilized in several parts of the country. These "negawatts" not only reduce overall electricity usage, they do so on command, meaning that they are and will continue to be critical resources for easing utilities through rough patches or demand spikes during the day. Demand response services also require very little infrastructure investment, making them excellent sources of near- and medium-term reliability services for regions that are particularly concerned about coal retirements. Of the several critiques we have seen mentioning the potential reliability impacts of the CPP, there has been little to no recognition of the important role storage and demand response in ensuring that electricity is provided reliably for years to come.[647]

3. Resilience Against Large System Shocks

The final system attribute grid operators have identified as endangered by shifting resource balance on the grid is its ability to respond quickly to large system shocks. These shocks typically occur when a large generator goes offline unexpectedly, or part of the transmission system experiences an unplanned outage. ERS providers are generally asked to respond to major disturbances in two ways: first, by remaining operational in spite of electricity fluctuations ("ride-through" capability); and second, by being able to start up and help restore frequency before the grid has returned to normalcy, sometimes without any assistance from the grid whatsoever (quick-start, sometimes "black-start," capability).[648] This is one area where

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[643] *NERC Reliability Review*, *supra* n. 591, at 25; *ERCOT Reliability Review*, *supra* n. 273, at 11-14.
[644] *ERSTF Concept Paper*, *supra* n. 638, at 8.
[645] *Id.* at 7-8 (further noting that "[l]arge, utility-scale wind and solar plants are already required to value the capability to limit production and control ramp rates to support system . . . reliability.").
[646] *NERC Reliability Review*, *supra* n. 591; *ERCOT Reliability Review*, *supra* n. 273; *ERSTF Concept Paper*, *supra* n. 638, at 15.
[647] *See,* e.g., *NERC Reliability Review*, *supra* n. 591, at 25 (mentioning the potential for storage technologies to help, but dismissing them as "not yet . . . commercialized").
[648] *ERSTF Concept Paper*, *supra* n. 638, at v, 9-10.

transition to cleaner electricity sources will unambiguously help: wind and solar plants are often more able to ride out disturbances, and return to service more quickly, because they are already necessarily designed to deal with fluctuating power over time, and they lack complicated thermal or mechanical systems that require significant amounts of time to restart.[649] In addition, the smaller capacity and more distributed nature of wind and solar plants address some of the root of the problem—a malfunction at a 50 MW solar facility is less likely to cause a large system shock than when a 800 MW central-station generator trips offline. [650]

Certain commenters have also looked at broad energy trends to highlight system vulnerabilities that arise when a grid relies too much on one type of resource. In particular, NERC in its critique of the CPP highlights the 2014 polar vortex, when particularly high demand for natural gas (for heating homes) strained local grids because pipelines appeared unable to supply natural gas plants. NERC has raised concerns that increasing the share of electricity produced by gas-burning power plants would make the grid more vulnerable to disturbances like that where single events act to reduce the supply of gas over a large region.[651] As an initial matter, the polar vortex did not, in fact, result in widespread power losses in the region, even though it was by any measure an extreme weather event; and that improved electricity transmission infrastructure can alleviate the risk that any one region suffers from a power shortage.

Also, sensible planning and low cost power plant upgrades would have avoided a large part of the problem. In the aftermath of the polar vortex, it has become clear that a big part of the problem leading to these capacity constraints was that coal and gas plants were simply unprepared for these climatic conditions. Most of the plants that were out of service were unavailable because of operational and mechanical problems like frozen coal stockpiles, boiler tube failures, and faulty ignition. Some plants, for example, failed to start up in the extreme cold after being off line for months. (By the end of January, when we experienced another extreme cold spell, more plants had recovered and were running normally.) Grid operators are now working on corrective measures to avoid these surprises, including requiring plants to test and verify their operational capability during the cold winter months. These tests include a “weekend check” requirement to assure that plants won’t have trouble starting up again after a prolonged break. Grid operators are also evaluating additional financial incentives to reward plant operators that deliver higher performance levels.[652]

Finally, pipeline capacity and gas supplies were not the problem in this situation; sufficient gas supply was available, but an anomaly in the power and gas markets kept some gas-fired generators from obtaining sufficient fuel on high-demand days. FERC and regional grid

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[649] *Id.* at 9-10.
[650] Milligan et al., NREL, *Cost-Causation and Integration Cost Analysis for Variable Generation*, NREL/TP-5500-51860 (June 2011), at 3.
[651] *NERC Reliability Review*, *supra* n. 591, at 9-10.
[652] Sustainable FERC Project, *The Polar Vortex and the Power Grid: What really happened and why the grid will remain reliable without soon-to-retire coal plants* (Ap. 2014).

operators have recognized this problem, and are working to address it: most recently, in October 2014 FERC shared its intention to better coordinate daily natural gas and electricity markets; enable gas-burning power plants to run temporarily on oil during emergencies; and make other market changes to resolve the issues that led to the capacity crisis during the polar vortex.[653]

We also note that that the obvious solution to NERC's concerns is increased fuel diversification. As NERC itself acknowledges, "the power industry relies upon diversification of fuel sources as a mechanism to offset unforeseen events . . . ensure reliability; and minimize cost impacts"[654]—but its solution is to continue excessive reliance on coal: MISO, which encompasses much of the region that was hardest hit by the polar vortex, relies on coal for over two-thirds of its electricity today. Taking the fuel diversification impetus to its logical conclusion only strengthens the case for investing in renewable resources, which currently make up less than a tenth of electricity generation in the same region, and demand-side resources. Unlike both coal and gas plants, wind and solar plants rely on "fuel sources" that do not need to be imported from anywhere, and the supply of which is far less likely to be interrupted uniformly across broad swaths of the country.

4. Utility-Grade Versus Distributed Renewable Generation

One important distinction raised especially by ERCOT in its modeling analysis has been between utility-scale, concentrated renewable generators, and distributed generation, especially solar generation, across the grid. As the system is currently structured, grid operators have "little to no visibility and control of distributed resources,"[655] with the result that they have raised reliability concerns across the country where power consumers look set to install distributed generation in significant amounts. ERCOT highlights two key changes that will be required to incorporate this generation without undermining grid reliability:

> "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 reliability, there would need to be increased consideration of operational activities on the distribution and transmission systems."[656]

NERC's ERS Task Force further notes that lack of control over distributed generation resources limits their ability to respond to fluctuations on the power grid, reducing their ability to provide routine frequency stability services or to help restore balance after grid

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[653] Press Release, FERC, Commission Reviews Actions to Improve Cold-Weather Grid Performance (Oct. 16, 2014), *available at* http://www.ferc.gov/media/news-releases/2014/2014-4/10-16-14-A-4-presentation.pdf, at 3.
[654] *NERC Reliability Review*, *supra* n. 591, at 9.
[655] *ERSTF Concept Paper*, *supra* n. 638, at 8.
[656] *ERCOT Reliability Review*, *supra* n. 273, at 13-14.

disturbances.[657] We do not agree with ERCOT or NERC that distributed generation represents a serious reliability concern in the near-term future—to give one example, the 9 to 13.5 GW of new solar capacity ERCOT's model anticipates over the next fifteen years is entirely utility-scale generation[658]—but to the extent some market changes are needed, we note again that grid operators are *already examining the various changes that may be required*.[659]

5. Overall Ability to Incorporate High Levels of Renewable Generation

As explained above, grid operators already have the tools necessary to adjust to the retirement of coal-burning power plants over the next fifteen years without seriously impacting the reliability of the power grid. Because much of the replacement power will likely come from renewable resources, this may result in renewable penetration rates of 30 to 40 percent or more in several areas of the country by 2030. Several recent studies have addressed this contingency specifically, considering whether and how it is possible to incorporate those levels of renewable energy using today's resources and technologies. These studies analyze a wide range of renewables incorporation, but their common conclusion is that high levels of integration are feasible. For a summary of these studies, please see Appendix 6.

To achieve these levels, the studies variously call for restructuring the energy market, advanced transmission planning and installation, increased utilization of demand response programs, additional electricity storage installations, incorporation of contingency reserve and curtailment capabilities into wind and solar facilities, independent improvements in ancillary service providers, and continued limited use of some fossil fuel plants as "peaker" facilities.[660] Implementing some or all of these measures will take time and money, but given that they are available now there is no reason for EPA not to expect that such a transition is possible. Each of these studies was done by grid operators and experts seeking to understand the implications of underlying market and policy trends favoring renewable energy development. In other words, the process of learning how to integrate large amounts of renewable energy is already underway, regardless of the Clean Power Plan. EPA's rule reflects and to some degree amplifies changes that are already happening in the system; it does not cause radically new and unprecedented circumstances.

B. Policy Conclusions

Because we are confident that a combination of renewable and demand-side resources, with appropriate advanced planning, can resolve all major reliability concerns grid operators have raised to EPA, we do not believe that EPA needs to take any measures to ensure that electricity is delivered safely and reliably to consumers across the country. Instead, we take this

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[657] *ERSTF Concept Paper*, *supra* n. 638, at 7-8, 14.
[658] *ERCOT Reliability Review*, *supra* n. 273, at 13.
[659] *ERSTF Concept Paper*, *supra* n. 638, at 14; ERCOT, 667NPRR-01 Ancillary Service Redesign 111814, *supra* n. 630.
[660] *See* summaries of the various studies attached as **Appendix 6.**

opportunity to respond to calls from utilities and regional grid operators for delayed implementation of the CPP, and for a "safety valve" that would exempt states and regions that are unable to meet their greenhouse gas emissions targets.

1. Delaying Implementation of the CPP

In response to perceived reliability concerns, NERC has called on EPA to "consider a more timely approach" to implementation of the CPP.[661] This call mirrors similar requests from SPP, which explicitly asks EPA to extend its proposed compliance schedule,[662] and several other utilities and grid operators, including PJM.[663] It is to be expected that grid operators and especially utilities would want more time to adapt, but any needed system changes anticipated by EPA's rule are achievable in the time allotted, and in fact are probably possible on a faster timeframe. Moreover, grid operators have already begun the process of integrating higher levels of renewable energy and responding to coal plant retirements caused by the worsening economics of coal. The CPP provides sufficient flexibility and lead time for utilities and grid operators to adapt. As noted previously, there are no targets that need to be met in 2020, nor are any sources specifically subject to continuous emission rate requirements. This absence of hard mandates early in the compliance period alleviates the need for the requested delays in implementation of the Clean Power Plan. Finally, unlike other EPA rules, such as the Mercury and Air Toxics Standards (MATS), that impose continuous emission rate requirements on coal plants, the Clean Power Plan imposes only annual emission rate constraints (see below for a more comprehensive comparison of CPP and MATS requirements).

The danger climate change poses to our society is too great to be held hostage to the apparent reluctance of grid operators to update their policies and infrastructure to accommodate clean electricity sources. As mentioned elsewhere in these comments, President Obama's international commitments, especially the recent U.S. – China agreement, require that we achieve greenhouse gas reductions at least equal to those required by the CPP from the power sector; failing to meet those objectives would set back global efforts to mitigate climate change significantly, when time is already of the essence.

2. Installing a CPP "Safety Valve"

The ISO/RTO Council ("IRC") has led efforts by grid operators and the power sector generally to secure a "reliability safety valve", which would blunt enforcement of the CPP in certain areas.[664] As proposed, this "safety valve" would subject EPA rules and/or state plans to a "reliability review," which could delay enforcement of the rule or program until a long-term

[661] *NERC Reliability Review*, *supra* n. 2, at 29.
[662] *SPP Letter*, *supra* n. 31, at 8.
[663] Heidorn, *supra* n. 635.
[664] *See id.*; ISO/RTO Council, *EPA CO_2 Rule—ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals* [hereinafter "*IRC Reliability Review*"] (Oct. 2014); *NERC Reliability Review*, *supra* n. 591, at 22; *ERCOT Reliability Review*, *supra* n. 273, at 2.

reliability solution is "developed and implemented."[665] Such reviews would be required on a rolling basis "at multiple stages both prior to the SIP being finalized and approved and at various steps during its implementation, as necessary."[666] And the rule would allow old coal plants to remain operational until this long-term solution is put in place.[667]

Allowing states an explicit reliability "safety valve" as described here is problematic for several reasons. First and foremost, it is unnecessary for the same reasons given above, and (as with the proposed CPP implementation delay) it would seriously impact greenhouse gas emissions by allowing old, dirty plants to continue operating well past when they would otherwise retire. Beyond that, it would significantly reduce motivation for regional and state grid operators to actively prepare for changes in customer demand, and related power needs and supplies of the future. As almost every grid operator has noted, significant advanced planning, and coordination with states in designing their plans, will be required to ensure power grids are equipped to manage our changing resource structures. A safety valve provision would undermine those conversations by removing a base level of accountability, and would therefore leave us less prepared in the long term. Finally, the provision proposed by IRC would impose a huge administrative cost on EPA, states, and grid operators, all of which would be required to go through a reliability determination and approval process at several stages throughout the plan approval process. Each of these additional administrative decisions could themselves be subject to challenge by industry or environmental groups, which could make the CPP implementation process even more difficult than the plan approval process already can be. We support state coordination with the ISO/RTO and neighboring states in developing their plans to ensure reliability, but do not believe that the formalized veto process proposed by the IRC will be constructive. The ISO/RTOs already have mechanisms such as reliability-must-run requirements as a final measure to ensure system reliability.

The supporters of IRC's safety valve proposal have justified it in part by comparing it to a safety valve provision EPA approved in conjunction with its December 2011 rule finalizing mercury and air toxics (MATS) standards for stationary sources. In finalizing the MATS rule, EPA also issued a statement of enforcement policy, noting that "where there is a conflict between timely compliance . . . and electric reliability, EPA intends to carefully exercise its authorities to ensure compliance with environmental standards while addressing genuine risks to reliability."[668]

The proposed safety valve goes much further than the one in the MATS rule, with no apparent justification for doing so. But even if it were identical to the safety valve in MATS, CPP differs in several key ways that remove any possible justification for a safety valve. The CPP

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[665] *IRC Reliability review*, *supra* n. 664, at 2.
[666] *Id.* at 3.
[667] *Id.*
[668] Giles, C., EPA, Assst. Administrator, Office of Enforcement and Compliance Assurance, *Memorandum: Enforcement Response Policy for Use of Clean Air Act Section 113(a) Administrative Orders in Relation to Electric Reliability and the Mercury and Air Toxics Standard* (Dec. 16, 2011).

operates through a SIP-like process, which allows states significant flexibility in designing standards to ensure that emission reductions do not come at the cost of serious damage to grid reliability. By contrast, the MATS rule sets uniform, national standards and does not allow states much leeway in enforcing those standards. State plans adopted under the CPP can also include provisions that allow curtailed plants to operate only when needed to generate reactive power needed to maintain system reliability. Again by contrast, the MATS rule sets absolute limits on each individual plant, and does not allow a plant to operate if it cannot comply with that limit. Finally, the CPP involves a slow ramp-up of emissions standards, and explicitly anticipates a gradual shift in grid makeup, with identifiable replacement power sources. MATS standards are fully enforceable on a specific date. Thus, none of the justifications leading EPA to limit its enforcement of MATS obligations come into play here, and EPA can and should safely disregard industry scaremongering.

C. A Consensus Vision for the Future

Although we clearly draw different conclusions from certain grid operators and utilities on the seriousness of threats to electricity reliability, and on whether policy "fixes" are required to ensure grid reliability, we close these comments by highlighting points of consensus. The most important message from all commenting parties is that implementation of the CPP is expected to contribute to the retirement of significant amounts of coal-sourced electricity over the next 15 years. To the extent feasible, EPA should help to ensure that states and grid operators plan for those retirements as soon as possible, make sure they fully understand the reliability implications of those retirements, and prepare their electricity grids to incorporate significantly higher levels of renewable energy.

As part of this, it is critical that state environmental regulatory agencies work closely with utilities and grid operators to ensure that states' individual plans are designed to minimize any disruptions to grid reliability. This may involve regional compliance options for states within a single RTO, or it may simply involve extensive consultations. Similarly, NERC, which has been looking mostly at national grid developments, should work more with regional RTOs, ISOs, and utilities to help them identify and respond to predictable changes in their resource mixes. Although it is certainly possible to manage renewable electricity in a way that minimizes disruptions to grid reliability, doing so will require advanced planning and understanding. To the extent appropriate, EPA should help facilitate these conversations.

XII. Munis and Co-ops

A. Public Power Utilities and Rural Electric Cooperatives Are Capable of Reducing the Carbon Emission Rates of their Affected Units.

EPA has requested comment on whether there are circumstances unique to municipally-owned utilities or rural electric cooperatives affecting the potential to reduce emissions from affected units owned or operated by those entities. This is appropriate: of the electricity generating units subject to CPP requirements listed in Energy Information Administration databases for which ownership information is available (2785 out of 4954 total units), a full 36 percent are owned by municipalities, cooperatives, or other public utilities, constituting about 20 percent of overall coal generating capacity.[669] In the context of coal, of the 753 coal units whose ownership could be determined, 64 are owned by municipalities, 67 by cooperatives, and 17 by other public utilities.[670] In other words, EPA cannot afford to ignore this huge section of the power sector in this country and still hope to achieve the overall greenhouse gas emission reduction goals it has set.

1. Characteristics of Municipal Utilities and Electric Cooperatives

Municipal utilities, or more broadly, "public power utilities" are vertically integrated utilities overseen by officials at a city or other local government. Typically state public utility commissions exercise no or only limited authority over municipal utilities. Taxpayer-issued bonds are the primary source of financial capital for public power utilities. Not all municipal utilities own or operate their own generation—some operate only the distribution facilities and purchase power on the wholesale market.

Rural electric cooperatives formed out of an effort by the federal government in the 1930s and 40s to electrify rural areas of the country, which had been neglected by traditional utility models. The Rural Electrification Administration, today the Rural Utilities Service, provided financing for the development of distribution infrastructure and establishment of electric services. Rural electric cooperatives come in two types: distribution cooperatives and the larger generation & transmission coops. Currently, there are approximately 840 distribution and 65 Generation & Transmission ("G&T") cooperatives.[671] The former do not own or operate generation, but collectively they own and operate 2.5 million miles of distribution lines, making up 42 percent of the distribution system.[672] Although these lines cover three quarters of the nation's land mass, they are concentrated in the sparsely populated middle of the country, including most of the central plains down to northern Texas, and so they deliver only 11 percent of all power produced in the United States, largely to rural customers, each year.[673] These distribution-only cooperatives, as well as municipal utilities that do not own or operate affected EGUs, will have no compliance obligations under the Clean Power Plan.

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[669] We analyzed which affected EGUs were owned in part by a municipal utility, other political subdivision, or rural electric cooperatives using the following data sources: EPA, *Data File: Unit-Level Data Using the eGRID Methodology*, *supra* n. 166, (for affected EGU identification); EIA 2012 Form 860 and 861 (for power plant ownership name and type data).

[670] *Id.*

[671] National Rural Electric Cooperative Association ("NRECA"), *NRECA Co-op Facts & Figures*, http://www.nreca.coop/about-electric-cooperatives/co-op-facts-figures (last visited Nov. 28, 2014).

[672] *Id.*

[673] *Id.;* NRECA*, Full Size Grand T Service Territory*, http://www.nreca.coop/wp-content/uploads/2013/07/FullSizeGandTServiceTerritory.gif (last visited Nov. 28, 2014) [hereafter, "NRECA Map"].

G&T cooperatives were formed by groups of distribution cooperatives to improve distribution cooperatives' ability to negotiate for power and ensure a reliable power supply. They own and operate generation and transmission facilities, and facilitate local distribution cooperatives' purchases of power from the market, providing expertise and additional bargaining leverage.[674] Thus, G&T cooperatives serve a large majority of distribution cooperatives, and increase the effective size, diversity and geographic range over which grid optimizing decisions (e.g., dispatch changes, heat rate improvements, emission trading, renewable energy investments) can be made. In other words, these larger markets give small rural collectives a greater opportunity to make the changes necessary to reduce greenhouse gas emissions.

Rural electric cooperatives have access to several sources of federal funding. For instance, the Rural Utilities Service ("RUS"), a program operated by the U.S. Department of Agriculture, provides funding, loan guarantees, and administrative support to rural electric cooperatives to enable them to construct distribution, transmission, and generation facilities.[675] As a result, the cost of capital for cooperatives is often lower than that available to investor-owned utilities.[676] Cooperatives can also obtain funding from the National Rural Utilities Cooperative Finance Corporation, which raises funds from capital markets to supplement the loan programs offered by RUS.[677]

2. Renewable Energy and Energy Efficiency Measures Taken by Municipal Utilities and Cooperatives

Some cooperatives and municipal utilities rely on some of the nation's oldest (and therefore least efficient) coal-burning power plants, and have remained reliant on coal even as the largest investor-owned utilities have begun to diversify their generation portfolio. As a result, the five utilities with the highest average rates of greenhouse gas emissions are four G&T cooperatives and one municipal utility (for Omaha, Nebraska).[678]

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[674] *See* Texas Elec. Cooperatives, http://www.texas-ec.org/about (last visited Nov. 28, 2014) ("TEC was established in 1941 as a coalition of electric cooperatives formed to have greater bargaining leverage with power suppliers.").

[675] U.S. Dept. of Ag., *USDA Rural Development*, http://www.rurdev.usda.gov/UEP_HomePage.html (last visited Nov. 28, 2014). This work is authorized under 7 U.S.C. § 901 *et seq.*

[676] Cooperative Research Network, *The Changing Cost of Solar Power: Financing Options for Electric Cooperatives* (Oct. 2013), *available at* https://remagazine.cooperative.com/About/PastIssues/Feb2014/Documents/TheChangingCostofSolarPowerFinancingOct2013.pdf, at 1.

[677] National Rural Utilities Cooperative Finance Corporation, *Overview*, https://www.nrucfc.coop/content/cfc/about_cfc/overview.html (last visited Nov. 28, 2014).

[678] Jeff McMahon, *5 Dense Carbon Polluters in EPA Crosshairs*, Forbes Magazine (June 1, 2014*), available at* http://www.forbes.com/sites/jeffmcmahon/2014/06/01/5-dense-carbon-polluters-in-epa-crosshairs/.

However, this fact does not paint a complete picture of publicly owned utilities' efforts to reform their electricity supplies. As detailed below, numerous cooperatives and municipalities have taken significant steps to incorporate large quantities of renewable electricity into their system mix, and to reduce local demand for electricity through efficiency measures. Many of these efforts have been undertaken solely to reduce costs for the city's residents or cooperative members, rather than being required by regulatory mandates. These efforts can and must continue; the CPP's building Blocks 3 and 4 offer huge opportunities for savings that will be required for these utilities to meet EPA's emission reduction goal.

The following two sections detail efforts by numerous public utilities to acquire renewable energy resources and increase efficiency, offer suggestions where appropriate, and conclude that cooperatives and municipal (and other public) utilities have numerous tools available to significantly improve their generation profiles over the next five to fifteen years.

a. Renewable Energy

Public power utilities and cooperatives are not strangers to renewable energy resources. As a percentage of total owned generation, public power utilities actually have a much higher percentage of renewable energy capacity than do investor-owned utilities: 18.5 percent versus 7.82 percent.[679] Thus, there is nothing inherent to the public power model that makes it more difficult to acquire or utilize renewable energy resources.

In fact, smaller public power utilities are uniquely well placed to incorporate large levels of renewable energy for several key reasons. The first, and perhaps most compelling, reason for this is that renewable energy can be built in smaller increments and scaled up as demand from the utility grows. This makes it a preferable investment especially for small utilities, because it prevents them from having to commit too many resources to any individual power source.

Municipal utilities are also well-suited to renewable energy projects because renewable generation projects are characterized by high up-front capital costs and low operation and maintenance costs. As public entities, municipalities can access low-interest bond funding models to finance these projects at much lower rates than investor-owned, or other publicly held, utilities.

Electric cooperatives are also able to take advantage of the long payback timeframes that come with renewable energy installations, because they have access to unique financing

[679] The American Public Power Association puts together an annual statistical report, select portions of which are available to non-members. The data supporting the above calculations are from the *2014-2015 Annual Directory & Statistical Report*, and specifically, the following tables: "U.S. Electric Utility Industry Statistics," *available at* http://www.publicpower.org/files/PDFs/USElectricUtilityIndustryStatistics.pdf, and "Renewable Capacity & Generation," *available at* http://www.publicpower.org/files/PDFs/RenewableCapacityandGeneration.pdf.

mechanisms for renewable energy development, including the Clean Renewable Energy Bond ("CREB"), which is available to electric co-ops, and state and local government to finance qualifying renewable energy facilities. According to USDA Secretary Tom Vilsack, "[s]ince 2009, USDA has funded over $1 billion in renewable energy projects that will generate more than 447 MW—enough energy to power 160,603 American homes annually."[680] The National Rural Utilities Cooperative Finance Corporation recently partnered with the Federated Rural Electric Insurance Exchange and the National Renewables Cooperative Organization to enable cooperatives to access tax equity financing for the development of community solar programs.[681] The National Rural Electric Cooperative Association ("NRECA") is also working with CFC and fourteen cooperatives from across the country, with support from DOE's Sunshot Initiative, to develop a standardized PV system package that will significantly reduce soft costs for solar PV installations.[682] This project, known as Solar Utility Network Deployment Acceleration, also offers training and technical expertise to help cooperatives with utility-scale solar projects.

Finally, as highlighted above, cooperatives tend to be concentrated in rural, open areas of the Midwest and plains states down to northern Texas, which happen to be the areas of higher onshore wind potential in the United States.[683] Thus, these cooperatives are able to take advantage of the lowest wind prices in the country and already have, as described further below.

i. Renewable Energy Success Stories

As a result of the several advantages highlighted above, numerous municipal and cooperative utilities have achieved great success in acquiring low-cost renewable energy resources. The following examples are just a few of many examples of municipal utilities making the prudent decision to take advantage of the low and stable long-term pricing available from renewable energy generators.

Many public power utilities are on the forefront of renewable energy development. Austin Energy, a municipal utility that owns a 50 percent share of the 1690 MW Fayette coal plant, has recently signed a 20-year power purchase agreement for 150 MWs of solar energy at

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[680] Vilsack, T., U.S. Sec'y of Agric., *Rural Electric Cooperatives: Leaders in Renewable Energy* (May 9, 2014), *available at* http://blogs.usda.gov/2014/05/09/rural-electric-cooperatives-leaders-in-renewable-energy/#sthash.SYjfYDfT.dpuf.

[681] Press Release, National Rural Utilities Cooperative Finance Corporation, CFC, Federated and NRCO Launch Pilot Program to Develop Electric Cooperative Solar Power Projects (Sep. 5, 2013), *available at* https://www.nrucfc.coop/content/cfc/news_analysis/news/press_release_09052013.html

[682] NRECA, *SUNDA (Solar Utility Network Deployment Acceleration) Project*, http://www.nreca.coop/what-we-do/cooperative-research-network/renewable-distributed-energy/sunda-project (last visited Nov. 28, 2014).

[683] NRECA Map, *supra* n. 673; NREL, *United States – Wind Resource Map*, http://www.nrel.gov/gis/pdfs/windsmodel4pub1-1-9base200904enh.pdf (last visited Nov. 28, 2014).

record low prices—below 5 cents per kWh.[684] This project will be completed in 2016, within 18 months of when the contract was signed, and will provide energy at far less than the prices Austin Energy currently pays for natural gas, coal, and nuclear energy.[685] Similarly, CPS Energy, a Texas municipal utility serving the San Antonio area, has also signed PPAs for over 400 MW of solar energy.[686] Outside of Texas, in late 2012, the Los Angeles Department of Water and Power (LADWP) signed two power purchase agreements with two solar power plants in Nevada, adding up to 460 MW.[687] LADWP has also made a commitment to be coal-free by 2025.[688] And finally, in late 2013, the 51 MW Hancock wind project in Maine announced that it would sell its output to the Burlington Electric Department, and to the Massachusetts Municipal Wholesale Electric Company ("MMWEC"), which has 17 member municipal utilities.[689]

The transition to renewable generation is not limited to large, progressive municipalities, though: Omaha Public Power District ("OPPD"), which was listed by Forbes as one of the five most polluting utilities in the country (per MWh generated), has been aggressively transitioning to renewable energy. With construction of the Grand Prairie Wind Farm and retirement of three of five units at the North Omaha coal-burning power plant, OPPD will be generating a third of electricity from wind power; the OPPD Board recently affirmed this step by publicly committing the utility to at least maintain this level of renewables for 20 years.[690] Meanwhile, high-level commitment at smaller utilities can achieve huge results: the

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[684] *See* Press Release, Recurrent Energy, Recurrent Energy Awarded 150 MW Utility-Scale Solar Contract By Austin Energy For Texas Solar Projects (May 15, 2014), *available at* http://recurrentenergy.com/press-release/recurrent-energy-awarded-150-mw-utility-scale-solar-contract-by-austin-energy-for-texas-solar-projects.

[685] Wesoff, E., *Austin Energy Switches from SunEdison to Recurrent for 5-Cent Solar*, Greentech Solar (May 16, 2014), *available at* http://www.greentechmedia.com/articles/read/Austin-Energy-Switches-From-SunEdison-to-Recurrent-For-5-Cent-Solar. Austin Energy also has a goal of achieving 35 percent renewable energy by 2020. *See* Austin Energy Resource, *Generation and Climate Protection Plan to 2020*, http://austinenergy.com/wps/wcm/connect/d9260888-0811-47a0-99d2-09b130121317/2012resourceGenerationClimateProtectionPlanto2020.pdf?MOD=AJPERES (last visited Dec. 1, 2014).

[686] Hill, J., *OCI Solar Power Breaks Ground on 400 MW San Antonio Solar Farm*, Clean Technica (Mar. 6, 2013), *available at* http://cleantechnica.com/2013/03/06/oci-solar-power-break-ground-on-400-mw-san-antonio-solar-farm/.

[687] Press Release, Los Angeles Dept. Water & Power, Los Angeles Takes Major Step Toward Clean Energy Future as LADWP Board Approves New Solar Power Agreements (Oct. 4, 2012), *available at* http://www.ladwpnews.com/go/doc/1475/1570631/Los-Angeles-Takes-Major-Step-Toward-Clean-Energy-Future-as-LADWP-Board-Approves-New-Solar-Power-Agreements. One PPA is for a 20-year term, at about 9.6 cents per kWh, and the other is a for a 25-year term at 9.2 cents per kWh.

[688] *Id.*

[689] Press Release, First Wind, MMWEC, First Wind Sign Contract for Hancock Wind Project Energy (Dec. 13, 2013), *available at* http://www.firstwind.com/wp-content/uploads/2014/03/MMWEC-PPA-Hancock-FINAL-121313.pdf.

[690] Atkeison & Johansen, *Listening to the Future: Omaha Public Power District Works on Maintaining Clean, Renewable Energy*, Prairie Fire (July 2014), *available at* http://nebraskansforpeace.org/oppd_works_on_clean_energy.

Sterling Municipal Light Department, a public utility providing power to a small Massachusetts town, has already built out solar projects sufficient to meet 30 percent of its peak load, and was recognized by the Solar Electric Power Association as the top utility in the country in terms of solar capacity (in watts) per customer, beating out much larger utilities in more solar-friendly regions by a huge margin.[691]

Rural electric cooperatives, both distribution coops and generation & transmission, are also increasingly making renewable energy part of their portfolios. As NRECA notes, "Co-ops are making significant investments in renewable resource generation, using loans from the Rural Utilities Service and other sources. With solar becoming more cost-competitive, solar development is growing quickly: "with the addition of 144 MW of solar capacity by 2017, cooperatives will more than double existing solar capacity," which is currently 95 MW across 34 states.[692] Electric co-ops are poised to invest hundreds of millions of dollars in new projects. In addition, co-ops purchase renewable energy from large projects such as the 31 MW Cimarron Solar Facility in New Mexico and the 7.7 MW Azalea Solar Power Facility in Georgia."[693] Meanwhile, nearly 40 cooperatives have developed or are planning community solar programs, recognizing that solar diversifies the fuel portfolio, and helps to build new community partnerships, which is a key cooperative value.[694]

But development is not limited to solar or wind power. Powering of existing dams to provide hydroelectricity has received significant attention in recent years, and has the potential to add up to 12 GW of new capacity, concentrated at least partially in regions where renewable energy utilization is otherwise quite low (i.e., the South and Midwest).[695] These projects require an especially long-term investment, for which municipalities and cooperatives are well suited. For instance, AMP-Ohio, which represents 123 municipal utilities across six states, is currently developing five hydropower repowering projects in Ohio.[696]

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[691] Solar Electric Power Association, *Sterling Municipal Light: A Small Utility Goes Big on Solar* (Oct. 28, 2014), *available at* https://www.solarelectricpower.org/utility-solar-blog/2014/october/sterling-municipal-light-a-small-utility-goes-big-on-solar.aspx#.VHWarpPF8vY; Solar Electric Power Association, *Solar Power Stats*, http://www.solarelectricpower.org/media/169342/solar-rankings-infographic-2013.pdf (last visited Nov. 28, 2014).

[692] NRECA, *Cooperative Solar: Driven by Cooperative Principles*, http://www.nreca.coop/wp-content/plugins/nreca-interactive-maps/esri-solar-story-map/index.html (last visited Nov. 28, 2014).

[693] Press Release, NRECA, NRECA Unveils Interactive Website Trackign Cooperative Solar Development (Nov. 7, 2014), *available at* http://www.nreca.coop/nreca-unveils-interactive-website-tracking-cooperative-solar-development.

[694] *Id.*

[695] Hadjerioua et al, DOE, *An Assessment of Energy Potential at Non-Powered Dams in the United States* (Apr. 2012) ,available at http://www1.eere.energy.gov/water/pdfs/npd_report.pdf, at 22-24.

[696] Bishop, N., *Water Ways*, Int'l Water Power and Dam Construction (June 20, 2008) ,*available at* http://www.waterpowermagazine.com/features/featurewater-ways/.

NRECA has produced an interactive map detailing how hundreds of cooperatives are diversifying their portfolios using renewable energy.[697] According to NRECA, as of April 2014 95 percent of NRECA's distribution members (794 out of 838) offer renewable energy options to their 40 million customers.[698] These cooperatives collectively own and buy over 5.9 GW of renewable capacity, including 1.1 GW of owned capacity, and 4.8 GW procured under long-term power purchase agreements.[699]

b. Energy Efficiency

Public power utilities and cooperatives also have significant advantages over investor-owned utilities that should enable them to at least match, and possibly exceed, national energy efficiency gain averages. Cooperatives are well placed to embark on significant energy efficiency programs for many of the same reasons they can be leaders in incorporating renewable generation: they have access to federal funding and development support that can be harnessed to make them leaders in the efficiency space. For instance, in December 2013 the U.S. Department of Agriculture expanded its RUS, which (as explained above) provides funding, loan guarantees, and administrative support to rural electricity cooperatives, by adding an Energy Efficiency and Conservation Loan Program.[700] Under this program, the Department plans to provide up to $250 million in energy efficiency loans specifically to rural cooperatives in 2014 alone, with more expected in future years.[701] As with renewables, cooperatives can obtain additional funding from the National Rural Utilities Cooperative Finance Corporation, which raises funds from capital markets to supplement the loan programs offered by RUS.[702]

In addition to these federal initiatives, many cooperatives are part of broader self-coordinated energy efficiency efforts, most notably including that orchestrated by Touchstone Energy. Touchstone Energy, founded in 1998, is a massive alliance of almost 750 local cooperatives, and acts both as a unified advocate for cooperative utility interests externally,

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697 *See* NRECA, *Cooperatives & Renewable Energy*, http://www.nreca.coop/wp-content/plugins/nreca-interactive-maps/RenewableEnergy (last viewed Nov. 28, 2014).

698 *Id.*

699 *Id.*

700 U.S. Dept. of Agriculture, *Energy Efficiency and Conservation Loan Program*, 78 Fed. Reg. at 73,356 (Dec. 5, 2013).

701 Press Release, U.S. Dept. of Agriculture, Agriculture Secretary Vilsack Announces energy Efficiency Loan Program to Lower Costs for Consumers, Reduce Greenhouse Gas Emissions (Dec. 4, 2013), *available at* http://www.usda.gov/wps/portal/usda/usdahome?contentid=2013/12/0228.xml.

702 National Rural Utiltiies Cooperative Finance Corporation*, Life at CFC*, https://www.nrucfc.coop/content/cfc/careers_at_cfc/life_at_cfc.html (last visited Nov. 28, 2014); *see also* Press Release, NRECA, Statement on USDA's New Energy Efficiency Rule (Dec. 4, 2013), *available at* http://www.nreca.coop/statement-usdas-new-energy-efficiency-rule (supporting USDA's efforts in this area).

and as a facilitator of inter-cooperative cooperation and standards setting.[703] It has been a leader in developing energy efficiency standards for its cooperatives, through its "Together We Save" program. Started in 2009, and the first (and to-date the only) utility-driven national effort to improve energy efficiency, the program offers model efficiency standards, individual consulting, and other support for local cooperatives seeking to increase energy efficiency at homes, farms, commercial and industrial facilities, and public facilities (airports, jails, etc.).[704]

Municipal and public utilities do not always have the same access to rural development assistance that cooperatives have, but they have other key advantages that should enable them to achieve significant efficiency improvements more easily than investor-owned utilities. As with renewable energy, a substantial chunk of energy efficiency investments have long-term payback windows, and municipal utilities are well suited to make those investments with low-interest bond issuances. But beyond that, unlike generation projects, which are usually centralized (the rise of distributed generation notwithstanding) and easily orchestrated by a single entity, efficiency programs require small improvements by thousands, or even millions, of individual electricity consumers. Private and cooperative utilities can establish incentive programs to achieve these gains, but municipal utilities are often directly connected to, or at least affiliated with, their municipal governments. As a result, they are more likely than other owners of covered facilities to be able to directly implement local regulations and measures that can achieve substantial efficiency gains.

As with cooperatives, public utilities also have access to federal and peer assistance to help implement effective energy efficiency measures. Most notably, the Department of Energy and EPA are facilitating the State and Local Energy Efficiency Action Network ("SEE Action"), which is a stakeholder-driven initiative (with municipal utilities like the Los Angeles Department of Water and Power and Tacoma Power in its executive group along with state utility commissions and other efficiency experts) that provides state and local governments with tools and resources to assist in implementing energy efficiency measures.[705] SEE Action has established a goal of achieving all available "cost-effective" energy efficiency improvements by 2020.[706]

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[703] Touchstone Energy Cooperatives, *About Touchstone*, http://www.touchstoneenergy.com/content/about-touchstone-energy-cooperatives (last visited Nov. 28, 2014).

[704] Touchstone Energy Cooperatives, *Together We Save*, http://www.togetherwesave.com (last visited Nov. 28, 2014); *see also* Touchstone Energy Cooperatives Business Energy Advisor, *Sector Reports*, http://bea.touchstoneenergy.com/content/sector-reports-0 (last visited Nov. 28, 2014) (detailing efficiency improvement options in a variety of sectors).

[705] State & Local Energy Efficiency Action Network, *Home Page*, https://www4.eere.energy.gov/seeaction (last visited Nov. 28, 2014).

[706] *Id.*

ii. Energy Efficiency Success Stories

As a result of all of these programs, many cooperatives lead the nation in energy efficiency efforts. Part of this leadership has come, as might be predicted, from federal assistance programs. Just over a month ago, the U.S. Department of Agriculture announced that it had issued its first two loans under the Energy Efficiency and Conservation Loan Program. The Department will lend $4.6 million to the North Arkansas Electric Cooperative to fund installation of new geothermal and air pumps, efficient lighting, weatherization measures, and other efficiency improvements throughout the region. It will lend $6 million to North Carolina's Roanoke Electric Membership Corporation to finance improvements to HVAC systems, appliance replacements, and building improvements.[707] Separately, the Alaska Village Electric Cooperative received a $200,000 grant from the Department of Agriculture Rural development unit to conduct energy audits of 42 businesses in native communities and identify key efficiency improvement opportunities.[708]

Even without federally subsidized programs, however, cooperatives still have achieved significant energy efficiency gains in recent years. As of 2012, over 96 percent of cooperatives had energy efficiency programs in place, 70 percent offered financial incentives to promote additional efficiency, and 73 percent had made public plans to significantly expand their existing programs over the next several years.[709] As with renewable energy, NRECA has produced an interactive map detailing hundreds of programs run by cooperatives, noting additionally which ones are part of broader programs like the "Together We Save" program.[710] To give just one example, in Minnesota, Great River Energy in 2008 spent $20 million on conservation and demand response programs, including nearly $7 million spent on lighting and pump improvements and distributed solar generation, enabling it to reap 636 million kilowatt-hours of lifetime savings and to reduce summer peaks by nearly 13 percent.[711]

Similarly, there are several municipal agencies who have taken positions of leadership in the field in pushing for significant energy efficiency improvements. Austin Energy has been a leader for decades in improving energy efficiency; by its own calculations, the utility reduced demand by 700 MW between 1982 and 2007, and it has set a goal of saving an additional 800 MW of demand by 2020. To accomplish this, the utility spends upwards of $36 million, composing almost 3 percent of its total budget, capturing energy savings opportunities,

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[707] Johnson, J., *USDA Efficiency Program Kicks Off with 2 Co-ops*, Electric Co-op Today (Oct. 23, 2014), *available at* http://www.nreca.coop/usda-efficiency-program-kicks-off-with-2-co-ops/.
[708] Holly, D., *Alaska Co-op Promotes Business Energy Savings*, Electric Co-op Today (Aug. 29, 2014), available at http://www.ect.coop/efficiency-conservation/energy-efficiency/alaska-co-op-promotes-business-energy-savings/73095.
[709] NRECA, *Electric Cooperatives and Energy Efficiency: A Snapshot*, https://www.nreca.coop/wp-content/uploads/2013/07/ElectricCooperativesEnergyEfficiencySnapshot.pdf (last visited Nov. 28, 2014) [hereafter, "NERC Snapshot"].
[710] *See* NRECA, *Cooperatives & Energy Efficiency*, http://www.nreca.coop/wp-content/plugins/nreca-interactive-maps/EnergyEfficiency/ (last visited Nov. 28, 2014).
[711] NERC Snapshot, *supra* n. 709.

including by providing rebates that encourage individual consumers to weatherize their homes, upgrade lighting, and make other such improvements.[712] In California's Central Valley, the Sacramento Municipal Utility District is another example of a leading municipal utility in this area, obtaining large demand reductions with a similar portion of their budget; this effort notably included a program incentivizing developers to make new buildings up to 30 percent more efficient than would be required under local energy codes.[713] And again, these success stories are not limited to large municipalities: Holyoke Gas & Electric has one of the most generous efficiency programs in the country, offering zero-interest loans to both commercial and residential customers to make various energy efficiency improvements.[714]

We note additionally that both cooperatives and municipal utilities have been industry leaders in implementing demand response programs, both to further reduce electricity demand and to contribute to overall system reliability—cooperatives provide about 10 percent of electricity sales, but are responsible for almost 25 percent of peak load management capacity, and 21 percent of customers with demand response capabilities.[715] (See our reliability comments for more information on demand response programs.) Some of this response has been achieved through innovative market structures that may help guide efforts elsewhere: in North Dakota, Minnkota Power reduced peak power demand using a power price "traffic light" alerting members when prices change and inviting them to reduce power usage in response.[716] But municipalities have also had significant success simply by providing meaningful funding to these programs—Fort Collins Utilities, a Colorado municipal utility, has had huge success developing demand response services, reducing total use by 1.5 percent at a cost of $0.02/kwh saved (making it the utility's lowest-cost electricity resource), simply by increasing annual demand response funding to $5 million a year.[717]

B. Summary

As this section of our comments demonstrates, there is significant potential for municipal utilities and cooperatives to meet greenhouse gas emission reduction targets just as investor-owned utilities and independent power producers will be expected to do. In fact, in many ways cities and cooperatives are better set-up than investor-owned utilities to achieve

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[712] Freischlag, K., Southwest Energy Efficiency Project, *Municipal Utility Energy Efficiency Programs: Leading Lights* (Mar. 2011), *available at* http://swenergy.org/publications/documents/Municipal%20Utility%20Energy%20Efficiency%20Programs%20-%20Leading%20Lights.pdf, at 2.

[713] *Id.* at 4.

[714] Holyoke Gas & Electric, *Commercial Energy Conservation Program*, http://www.hged.com/customers/save-energy-money/for-business/commercial-energy-conservation/default.aspx (last visited Nov. 28, 2014); Holyoke Gas & Electric, *Residential Energy Conservation Program*, http://www.hged.com/customers/save-energy-money/for-home/residential-energy-conservation/default.aspx (last visited Nov. 28, 2014).

[715] NERC Snapshot, *supra* n. 709.

[716] *Id.*

[717] Freischlag, *supra* n. 712, at 1-2.

these reductions through expansive renewable energy and demand side management programs. EPA did not specifically address the question how to apply the CPP to these energy providers, and so we ask that EPA allow for further notice and comment on any specific proposals relating to them.

We support EPA addressing these issues in depth, however, because states often do not exercise the same level of jurisdiction over municipalities and cooperatives that they do over investor-owned utilities, making the state plan-driven process less optimal for sources operated by cooperatives and publicly-owned utilities. We also note that this potential complication provides additional support to our recommendation, shared elsewhere in these comments, that enforcement of the CPP fall entirely on sources (and by extension on all utilities, including municipalities and cooperatives), rather than on states, who have limited control over their own power infrastructure. We note that NRECA has asserted that the CPP "goes too far, too fast."[718] However, NRECA's stated concerns about reliability mirror those shared by other major grid operators, which we have rebutted elsewhere in our comments.

That said, cooperatives in particular serve some of the poorest and least connected parts of the United States, and so EPA should explore opportunities to enforce the CPP without unduly impacting poor communities.[719] The CPP offers a significant opportunity for community investment in energy efficiency and distributed renewable generation, programs which have the potential to create high-quality jobs, and EPA should work with RUS to ensure that guidance offered on these types of programs is appropriate for, and well-communicated to, cooperatives. In addition, EPA should consult with the Rural Utilities Service to understand whether the framework for RUS's existing financing tools could be improved in order to facilitate CPP compliance. For example, RUS may be able to streamline applications for compliance-related financing to ensure approval in time for Clean Power Plan measures, or seek further appropriations to make additional financing available. EPA should also consider other existing mechanisms that already encourage renewables and efficiency build-out, and explore how harnessing these various support networks can help municipalities and coops to reduce their greenhouse gas emissions with minimal disruption.

XIII. Other Issues

A. EPA Should Shorten and Accelerate the Rule's Compliance Schedule and Should Commit Now to An Eight-Year Review

While EPA's primary Clean Power Plan proposal would extend the compliance period until 2030, the agency has also solicited comment on an alternative compliance period ending in 2025, with interim goals applying between 2020 and 2024. We urge EPA to adopt the shorter

[718] Press Release, NRECA, NRECA Statement at EPA's DC Clean Power Plan Hearing (July 29, 2014), *available at* http://www.nreca.coop/nreca-statement-at-epas-dc-clean-power-plan-hearing.
[719] See our environmental justice comments for more information on impacts to poor and diverse communities.

time frame with two additional features. First, EPA should advance the compliance schedule to begin as early as January 2018, rather than 2020. Second, the agency should engage in a continuous internal review of the rule during the compliance period and should commit to issuing a revised set of emission guidelines that would take effect in 2026.

Under either the 2025 or 2030 formulation of the rule, states are expected to cut their CO_2 emissions according to the levels provided under Building Blocks 1 and 2 in the first year of compliance, while Building Blocks 3 and 4 require incremental cuts spaced out over the remainder of the compliance period. What this means is that the substantial majority of reductions occur early on in the compliance schedule, while later years contribute relatively little in the way of emission cuts. While we approve of the agency's decision to require steep cuts early on, we believe that RE and EE—which are phased in more slowly under Blocks 3 and 4—will provide much greater opportunities for emission reductions than the rule currently anticipates. Renewable technologies in particular are rapidly dropping in price, whereas fossil fuels will become increasing expensive between now and 2030. Between now and 2020, we expect the changing economics of the electricity sector to make RE investments significantly more attractive across the board, including in states that are currently resistant to these innovations.

EPA can capitalize on the changing landscape of energy markets by shortening and advancing the rule's compliance schedule while committing to issue updated performance standards that will take effect in 2026. The rule currently is scheduled to take effect in 2020, but there is no reason that the leading states cannot submit plans by 2016, with approval in 2017 and a phased-in compliance schedule beginning in 2018. An accelerated schedule will both reward states that have and plan to adopt the kinds of policies that will achieve significant CO_2 reductions while motivating the less-inclined states to draft an approvable plan, lest they be subject to an EPA-issued federal plan.

EPA should then be in a position to commence an internal review of the rule by 2020-21, with a proposed revision of the performance standards issuing in 2021-22 and a final rule scheduled for 2022-23. States would have up to two years to submit revised plans, allowing for a compliance period for the updated standards commencing in calendar year 2026. By adopting this accelerated schedule and committing to an 8-year review (similar to the 111(b) approach), the agency can ensure that the emission reductions required in the second half of the next decade are sufficiently stringent and that the rule remains maximally effective.

We also note here that we strongly oppose any effort by EPA to relax the stringency of the glide path or phase in emission reductions under Building Blocks 1 and 2, an issue raised in the agency's recent NODA. *See* 79 Fed. Reg. at 64,545-46. If EPA preserves the current rule schedule, states and utilities will have five years after EPA finalizes the Clean Power Plan and two to three years after state plan approval to prepare for implementation. Moreover, under the current proposal, the interim goal is based on an average across all years, rather than on performance in any specific year, and the final goal need only be attained at the end of the compliance period. As such, states are free to apportion their emission reductions across the period however they choose, so long as the interim and final goals are met. This measure of flexibility provides a sufficient buffer against stranded assets and other technical challenges toward achieving compliance, and no additional relaxation of the glide-path is necessary, irrespective of when the compliance period begins and ends. We therefore urge EPA not to accede to any requests that it establish a more lenient pathway toward compliance in the final rule.

B. Non-BSER Measures and the Symmetry Principle

EPA has expressed that it may allow states to use non-BSER measures for compliance purposes. If it does so, EPA must adhere to what we refer to as the "symmetry principle": the stringency of the state goals must reflect the full set of measures that can be used to comply.

In addition to the emission reduction measures included in EPA's four building blocks, the agency cites a number of other methods for cutting power plant emissions. These include fuel-switching or co-firing at individual units, retrofitting existing fossil units with carbon capture and storage ("CCS") technology, constructing new NGCC capacity to replace a portion of existing coal-fired generation, and implementing heat rate improvements at existing gas- and/or oil-fired EGUs. See 79 Fed. Reg. at 34,875-77. Although it has not included these measures as part of its BSER determination EPA has solicited comments on whether states should be permitted to implement these or other measures instead of, or in addition to, the emission reduction techniques in the building blocks in order to demonstrate compliance with their reduction targets. *See id.* at 34,923.

As we discuss in section V.A.2.f, we urge EPA to include in Block 1 heat rate improvements at gas- and oil-fired EGUs in addition to coal-fired EGUs. We also believe EPA should consider incorporating grid efficiency upgrades in the EE measures permitted under Block 4. Fuel switching and co-firing can reduce emissions at individual units, and EPA should include those measures in its BSER calculation for Block 1 if they will be allowed for compliance. However, EPA should neither include new NGCC capacity in computing state targets nor should it allow states to rely on new NGCC units for compliance. It may be appropriate to exclude certain measures that would reduce emissions from the BSER calculation based on a robust analysis of cost and energy requirements, while still allowing those measures to count for compliance if states or affected sources choose to invest in those measures. That is the exception, however. As a general matter, the symmetry principle should control: if a measure is available for compliance, it should be included in the BSER calculation.

C. New Source Review Issues

As EPA correctly observes in the proposed rule, measures that affected sources implement to comply with the rule are unlikely to trigger New Source Review ("NSR") permitting requirements. *See* 79 Fed. Reg. at 34,928. EPA requests comment on two issues concerning state plans' relationship with the Act's NSR provisions: (1) the level of analysis and plan requirements that may be needed to ensure that sources will not trigger NSR when complying with the state's section 111(d) plan, and (2) whether state plans could include provisions determining, as a matter of law, that affected sources' actions to comply with plan requirements would not subject those sources to NSR. 79 Fed. Reg. at 34,928-29. The most straightforward way for states to address these issues is to include in their plans source-specific limits on affected sources' emissions or operations that are sufficiently rigorous to ensure the sources will not generate enough emissions to trigger NSR. Consistent with EPA's NSR regulations, any such limits must be enforceable as a practical matter. *See* 40 C.F.R. § 51.166(b)(4). Therefore, among other things, adequate testing, monitoring, and record-keeping procedures would have to be included in the state plan to ensure affected sources remain below the NSR thresholds.

Beyond such source-specific restrictions in the state plan, however, states cannot lawfully or rationally include in their plans generic provisions that effectively exempt sources in advance from NSR. The Act does not authorize such exemptions, nor can EPA allow them, regardless of whether the plan's purpose is to reduce emissions. *See* 42 U.S.C. §§ 7475, 7479, 7502(c)(5). EPA attempted to create a similar exemption in its 1992 and 2002 NSR regulations, which provided that "environmentally beneficial" pollution control projects would not constitute a modification triggering NSR. *See* 40 C.F.R. §§ 52.21(b)(2)(iii)(h), 52.21(b)(32), 52.21(z) (2003). The D.C. Circuit invalidated the pollution control project exemption in *New York v. EPA*, 413 F.3d 3, 41-42 (D.C. Cir. 2005), holding that the CAA does not permit EPA to exclude a class of activities from being a "modification" that would trigger NSR. Therefore, EPA may not permit states to exempt affected sources' actions to implement the Clean Power Plan from triggering NSR.

Moreover, EPA fails to identify any way that states could reliably assure that a system providing flexible compliance options such as the Clean Power Plan would foreclose specific sources from taking actions that would trigger NSR. Even if states were able to definitively show through rigorous analysis that an affected source's implementation of section 111(d) plan provisions would not trigger NSR, including in the plan an exception from NSR as EPA suggests would create more problems than it would solve. For example, exempting affected sources' actions to comply with plan requirements from triggering NSR could lead to difficult-to-answer questions about whether particular physical changes made at the affected source were undertaken to comply with 111(d) plan requirements, or were made for another purpose. Finally, to the extent that an affected source triggers NSR due to an emissions increase that results from a physical change or change in method of operations, exempting that source would undermine the purposes of the NSR program and put neighboring communities at risk. Such sources should be required to comply with NSR requirements, including emission limits based on best available control technology ("BACT").

We would also suggest that there is no Federal or State interest in "ensuring" that the NSR provisions of the Clean Air Act are not triggered by sources. The NSR provisions of the Act wisely and appropriately require upgrading pollution controls at existing units if those units are modified in a way that increases annual emissions. We note that the only projects that are likely to increase annual emissions, and thereby trigger the obligation under NSR provisions to install modern controls, are those projects that reduce forced outages that are endemic in the aging U.S fleet. Many of these projects also extend the useful life of existing units. There is no valid public policy interest in artificially extending the "grandfathering" of existing units that was provided by Congress in 1970 under the expectation that existing units would soon retire and no longer emit at unnecessarily high levels.

Nothing in the Clean Air Act prevents owners of older, grandfathered units from upgrading and improving the performance of those units, provided the owners (1) install modern pollution controls or (2) accept enforceable permit conditions that limit annual emissions to levels emitted in recent years of operation. The particular path that operators of existing EGUs may take to comply with CAA Section 111(d) obligations and other requirements of Federal and State law is their decision – not a Federal or State decision. However, simply exempting sources from NSR provisions would encourage "life extension" programs at fossil fuel-fired EGUs that would undermine one of the fundamental structures of the Clean Air Act, the eventual end to grandfathered status where modifications increase annual emissions. It would also undermine the fundamental purpose of the Climate Action Plan – to transition the U.S. electric supply sector to lower carbon intensity technologies. The orderly retirement of existing units and transition to low carbon electricity generation would be severely disrupted by the NSR exemption that has been suggested.

D. EPA Has Correctly Based Its Emission Targets on Net Rather than Gross Generation

Every power plant uses a portion of the electricity it generates (which is called the auxiliary or parasitic load) to run internal processes, such as feedwater pumps, cooling fans, and pollution reduction systems. A unit's net generation subtracts the auxiliary load when determining how much electricity the unit generates, such that it only accounts for electricity actually delivered for sale to the grid. By contrast, gross generation standard does not factor out the auxiliary load, but simply calculates the total amount of electricity produced by the unit's generator. EPA has properly calculated all of the emission targets in the Clean Power Plan on a net output-based rather than gross output-based standard. By considering only net generation, EPA's plan encourages states to minimize the auxiliary load of their electric fleet and maximize internal efficiencies. This will both help curb power plant CO_2 emissions and reduce the cost of generating electricity for sale to the grid, which will, in term, help contain electricity costs to consumers. We therefore strongly support EPA's decision to use a net rather than gross output-based standard for its 111(d) rule and urge the agency to maintain the net-based standard in the final rule.[720]

[720] On the other hand, the agency's 111(b) rule follows a gross output-based standard. We opposed this decision in our comments to the agency and reiterate here our belief that all section 111 standards should be based on net generation. *See* Sierra Club et al, *supra* n. 115, at 106-114.

E. Social Cost of Carbon

1. EPA Has Properly Relied On the Federal Government's Estimates of the Social Cost of Carbon.

Calculating the social cost of carbon ("SCC")—the monetized damages associated with an increase in carbon emissions and the corresponding benefits that would result from curbing emissions—is a necessary step toward developing regulations that reduce CO_2 pollution and mitigating the many threats posed by climate change. SCC estimates allow EPA to incorporate the social benefits of reducing CO_2 emissions into its regulatory analyses and are critical to assessing the overall costs of the proposed standards.[721]

It is important to note that section 111 of the Clean Air Act does not require a traditional cost-benefit analysis, but merely a showing that an agency's determination of BSER does not impose costs that are exorbitant or too high for industry to bear. *See, e.g. Essex Chem Corp.,* 486 F.2d at 437; *Lignite Energy Council,* 198 F.3d at 930; *Portland Cement II,* 513 F.2d at 508. EPA may broadly consider costs, including the SCC, to make a reasoned determination that the benefits of the regulation justify its costs, but the law is clear: section 111 "grant[s] the agency a great degree of discretion in balancing" the different factors involved in a BSER determination, and "EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant." *Lignite Energy Council,* 198 F.3d at 933 (internal citations omitted). We therefore discuss the benefits of the proposed rule not to indicate that a cost-benefit analysis is necessary, but to help demonstrate that the projected costs of implementation are not unreasonably high and to underscore the strong public policy rationale supporting these proposed standards.

In analyzing the proposed rule's benefits, EPA properly relied on the federal government's most recent estimates of the social cost of carbon. Over the course of several years, the designated interagency working group ("IWG") has developed a series of values to represent the cost that each metric ton of CO_2 emissions will impose on society. The IWG utilized three cutting-edge integrated assessment models ("IAMs")—DICE, PAGE, and FUND—to formulate these values. The most recent four SSC estimates for 2020 are \$13, \$46, \$68, and \$137 (2011\$) per metric ton of CO_2, reflecting discount rates of 5 percent, 3 percent, 2.5 percent, and the 95th percentile of 3.0 percent values, respectively.[722] This range of estimates helps to represent the inherent uncertainty in projecting the social cost of carbon decades into the future.[723]

Climate change and its economic consequences are enormously complicated, and modeling these processes requires grappling with a large degree of uncertainty. Accordingly,

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[721] IWG, *supra* n. 725, at 2.
[722] *RIA* at 4-10. In the 2013 TSD, the IWG reports these values in \$2007 dollars, so they appear slightly lower in that document due to inflation between 2007 and 2011.
[723] *Id.* at 8-11.

some simplification of these processes is necessary in order to develop a useful framework for modeling the impacts of climate change and the costs associated with those impacts. As the IWG has acknowledged, any effort to quantify and monetize climate harms raises deep questions of science, economics, and ethics and should be viewed as provisional.[724] That being said, these three IAMs incorporate decades of peer-reviewed scientific research and a range of scenarios for emissions, population growth, and economic activities. Furthermore, these modeling systems have been and will continue to be updated to account for the latest advances and input from experts in the fields of environmental science and economics.[725] The latest SCC estimates from November 2013 relies on the most recent versions of each modeling system. Among other technical updates, each model for the first time now accounts for damages that will result from rising sea levels, which is the primary reason for the updated SCC values' increase over the 2010 estimates.[726] The IWG will continue to investigate potential improvements to the way in which economic damages associated with CO_2 emissions are quantified and will periodically refine the federal SCC estimates accordingly.[727]

Cumulatively, these models represent the best tools currently available for determining an appropriate social cost of carbon, and IWG's efforts pass legal muster from a standpoint of federal regulatory law and policy. Moreover, the IWG's most recently updated estimates utilized accepted science, economics, and technical modeling. EPA's reliance on those estimates in support of the proposed rule was therefore reasonable and justified.

2. The True Social Cost of Carbon Is Likely Much Higher Than The Federal Government's Estimates.

Sierra Club and other environmental organizations have proposed revisions to the IWG's approach that would more robustly reflect the full costs that CO_2 emissions impose on global society.[728] Specifically, we continue to advocate for changes to the damage function and discount rates utilized in the modeling programs. Climate change is not always a linear process, and once the planet crosses a certain temperature threshold, abrupt and irreversible changes are likely to occur, causing massive disruption to people and natural systems. The damage function used in the modeling platforms calculates the loss of gross domestic product ("GDP") as a quadratic function of increased global surface temperature but does not properly account for economic damages that are likely to intensify at a much faster rate once the global surface temperature increases past approximately 3 degrees Celsius above pre-industrial levels.[729]

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[724] IWG, *supra* n. 725, at 2.
[725] IWG, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12,866* (Feb. 2010), attached as **Ex. 72**, at 1-2, 4, 29.
[726] IWG, *supra* n. 725, at 6-8, 10.
[727] *Id.* at 4; IWG, *supra* n. 725, at 1-2, 4, 29.
[728] *See generally, e.g.*, Sierra Club, *Comments on the Interagency Working Group's (IWG) Technical Support Document: Social Cost of Carbon (SCC) for Regulatory Impact Analysis Under Executive Order 12866* (Docket Not.OMB-2013-0007-0083) (Feb. 25, 2014), attached as **Ex. 73** and incorporated by reference. herein.
[729] For a more detailed discussion of this issue, *see id.* at 7-9.

Additionally, selecting the appropriate discount rate is critically important, as climate change is a global phenomenon that occurs over centuries, and small adjustments to the discount rate make a large difference over such an extended time frame. We contend that the discount rates used in the modeling platforms minimize the social cost of carbon estimates, as they do not accord a sufficient measure of equity between current and future generations. Rather, they presume a constant measure of positive economic growth even though the models predict significant GDP losses due to climate change. Moreover, they do not accurately reflect the level of risk aversion that policymakers are likely to exhibit in the face of increasing harm from climate change. [730] For these reasons, the IWG's current approach to the SCC dramatically underestimates the true costs of carbon. By reevaluating and reformulating the damage function and discount rates, the IWG will generate a much more accurate SCC for federal regulators, including EPA, to use in their policymaking.

It is also important to recognize that many climate change impacts are difficult or impossible to quantify in a meaningful way, and it is critical that future estimates account for the non-monetizable costs of CO_2 emissions. For example, as noted earlier, the IPCC cites research indicating that 15 to 37 percent of plant and animal species worldwide may be committed to extinction by the mid-21st century if temperatures increase 1.6 to 1.8 degrees Celsius above late 20th century levels.[731] This would not only have dire economic consequences by drastically disrupting the food supply, but would also have immense non-monetizable consequences to our natural world and ecological heritage. A quantitative assessment of the social cost of carbon—even one that accounts for biodiversity loss—cannot capture the full extent of these dire impacts. Similarly, the permanent loss of coastal and island communities due to rising ocean levels would have social, cultural, and ethical ramifications that resonate far beyond a quantifiable dollar figure, as would many other consequences of climate change. [732]

EPA and the IWG acknowledge these and other limitations with the federal SCC analysis, including the "incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in extrapolation of damages to high temperatures, and assumptions regarding risk aversion."[733] EPA also notes in its RIA that the "SCC estimates are likely conservative," and the IPCC has similarly found it "very likely" that monetized estimates of climate harm such as the federal SCC "underestimate the damage costs because they cannot include many non-quantifiable impacts."[734] Therefore, comprehensive regulations limiting CO_2 emissions, such as the Clean Power Plan, will yield benefits that exceed the SCC's predictions and extend far beyond the economic realm. It is critical that EPA bear this in mind as develops its final emission guidelines.

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[730] *See id.* at 9-15 for further analysis of the discount rate.
[731] IPCC, *supra* n. 9, at 243.
[732] *See* Sierra Club, *supra* n. 728, at 3.
[733] *RIA* at ES-15.
[734] *Id.*

3. The Federal SCC Values Demonstrate That the Clean Power Plan's Benefits Far Exceed Its Costs.

Even the current (and overly conservative) SCC estimates indicate that the benefits of EPA's Clean Power Plan proposal are substantial and far exceed its costs.[735] Assuming a 3 percent discount rate, EPA estimates net benefits in 2020 to be $27 to $50 billion (2011$) under a state-based approach for the 2030 compliance timeframe.[736] By 2030, this range of benefits increases to $49 to $84 billion.[737] These estimates include the quantified benefits of reduce climate harm as well as the health co-benefits from reduced emissions of other harmful air pollutants, such as SO_2, NO_x and $PM_{2.5}$.[738] By contrast, EPA estimates that the rule's costs will range from roughly $5 and $9 million per year during the compliance period.[739] Even without taking into account important categories of impacts, such as methane emissions or ecosystems effects, it is clear that the estimated climate benefits and human health co-benefits far outweigh the compliance costs for all regulatory options and compliance approaches included in the proposal.[740]

In short, the IWG's most recent SCC estimates point to the proposed rule's substantial regulatory value, and EPA properly incorporated them into its costs analyses. The federal SCC values are derived from rigorous, well-tested modeling systems that reflect the cutting edge of environmental economic theory. Nevertheless, we also acknowledge the limitations of the methods used to calculate the current SCC values and will continue to push for adjustments to IWG's methodology to better reflect the true (monetizable and non-monetizable) costs that CO_2 emissions impose on global society.

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[735] *Id.* at 7-2.
[736] *Id.*
[737] *Id.*
[738] *Id.* at 8-2.
[739] *Id.* at 3-1
[740] *Id.* at 8-3.

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