RFF REPORT

Comments to the US Environmental Protection Agency on Its Proposed Clean Power Plan

Dallas Burtraw, Carolyn Fischer, Clayton Munnings, Karen Palmer, Anthony Paul, Nathan Richardson, Jhih-Shyang Shih, and Roberton C. Williams III

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US Environmental Protection Agency
EPA Docket Center (EPA/DC), Mailcode 28221T
Attention Docket ID No. OAR–2013-0602
1200 Pennsylvania Avenue, NW
Washington, DC 20460

On behalf of Resources for the Future (RFF), we are pleased to offer comments to the United States Environmental Protection Agency (EPA) on its Clean Power Plan (CPP) proposal, released June 2, 2014.

As you know, RFF is a nonprofit and nonpartisan organization that conducts independent research—rooted primarily in economics and other social sciences—on environmental, energy, and natural resource policy issues. RFF neither lobbies nor takes positions on specific regulatory proposals, although individual researchers are encouraged to express their unique opinions—which may differ from those of other RFF experts, officers, and directors. All RFF research is available online, for free.

For the past several decades, RFF experts have helped decisionmakers better understand climate policy challenges and assess the costs and benefits of possible solutions, such as a clean energy standard, Clean Air Act regulation, and various state-level programs, among others. As always, the goal at RFF is to identify the most effective ways—from an economic perspective—to meet environmental objectives through regulation, policy, or market mechanisms. To that end, researchers at RFF have been actively analyzing EPA's Clean Power Plan proposal.

Several RFF experts have provided their own comments on the issues below. Please feel free to contact them directly with questions.

In addition, we have attached the responses to date on RFF's Expert Forum on EPA's Clean Power Plan (Appendix A). This forum engaged experts from industry, academia, NGOs, and

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other places to comment on key issues in the plan. The views expressed by these experts do not represent RFF's views and do not represent formal comments to EPA. However, we hope they will be helpful in providing a diverse and broad view on the issues.

If you have any questions or would like additional information, please contact Ray Kopp at kopp@rff.org.

Sincerely,

Phil Sharp	Ray Kopp
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Resources for the Future	Resources for the Future

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How can coal power plants reduce emissions and be made more efficient—and at what cost (building block #1)?

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This comment is an updated version of what appeared originally as part of RFF's Expert Forum on EPA's Clean Power Plan on October 7, 2014. All other responses in the forum are attached in their entirety in Appendix A.

One of the ways to reduce emissions as part of EPA's proposed Clean Power Plan is to improve the operation of coal-fired power plants. EPA finds that the heat rate—the heat content of fuel input per unit of electricity output—at existing plants can be reduced by 6 percent on average across the fleet. This would correspond to an equivalent reduction in emissions rate. Is this goal attainable?

Empirical evidence from research at RFF[1] suggests the following:

1. EPA's goal is technically plausible.
2. The costs could be low, at least for modest heat rate improvements of 1 to 2 percent.
3. The cost of a 6 percent improvement in heat rate (while holding utilization constant) could be significant at many plants.
4. However, the opportunity to co-fire with biomass at coal plants could double the reduction in the emissions rate (which is closely related to heat rate) for coal plants at the same marginal cost.
5. The flexibility of this proposal to average across plants and to shift generation to more efficient plants means that greater opportunities may be available at lower cost, compared to when plants are examined on an individual basis.

My colleagues and I examined data on the performance of coal plants in 2008, sorting plants by boiler type and other characteristics. Our results indicate that the average heat rate would be reduced by 5.5 percent—without changing the utilization of individual plants—if each plant improved to match the operating performance of the best 10 percent in its group. This indicates that EPA's goal is technically plausible.

In its technical documents, EPA examines the operation of plants over many years and finds substantial variation in heat rate at individual plants on an hourly basis. This suggests that improvements are possible if that variation could be reduced. EPA suggests that 4 percent improvement could be achieved on average through changes in maintenance and operation at individual plants at low cost or no cost, and another 2 percent could be achieved through capital investments at individual plants.

We examined 25 years of operation of coal plants to see how their heat rates responded to changes in relative fuel prices while holding constant the utilization of the plants. Our findings support EPA's claim that costs are low, at least for modest heat rate improvements of 1 to 2 percent. Larger changes are outside the range of variation observed very frequently, and it is difficult to extrapolate, but clearly the marginal costs would increase with increasingly stringent improvements.

If poor heat rates waste fuel, why would such opportunities for heat rate improvements exist across the fleet? There are multiple possible explanations, at least in the short run. These include automatic fuel

[1] Linn, Joshua, Erin Mastrangelo, and Dallas Burtraw. 2014. Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act. *Journal of the Association of Environmental and Resource Economists* 1(1/2). DOI: 10.1086/676038. http://www.jstor.org/stable/10.1086/676038

adjustment clauses in some states that may reduce the incentive to save fuel costs, liquidity constraints in some systems that may make it difficult to fund investments, and the so-called new source review test—which is the threshold where investments to improve a plant's operation could enable its greater utilization and thereby increased emissions of other pollutants. This test could trigger a requirement for tens of millions of dollars in expenditures to improve controls for other pollutants, a cost that may deter investments to improve heat rates.

Nonetheless, opportunities to reduce costs should not go unrealized in the long run. While the results from Linn et al.[2] suggest the cost of a 6 percent improvement in heat rate (while holding utilization constant) could be significant at many plants, a central characteristic of the Clean Power Plan is that stringency is built on EPA's findings of what is technically possible. EPA does not require specific measures to be taken. That is, a heat improvement of 6 percent on average in the operation of the coal fleet does not require a 6 percent improvement at any given plant. One way this is relevant is that large capital investments, which EPA suggests could lead to a 2 percent improvement in heat rate on average across the fleet, may result in improvements of 10 percent at an individual plant. For example, investments such as major overhaul of a plant's turbine are expensive and would only be observed at some plants—but they would lead to substantial reductions in heat rate. The flexibility of this proposal to average across plants and to shift generation to more efficient plants means that greater opportunities may be available at lower cost, compared to when plants are examined on an individual basis.

An equivalent emissions rate reduction could be achieved if the co-firing of biomass with coal were given credit in the calculation of a demonstrated emissions rate. EPA has indicated the agency expects to recognize the benefits of combusting waste-derived and certain forest-derived industrial byproduct feedstocks. Recent modeling indicates that if biomass co-firing were credited, virtually 100 percent of the fuel used would be waste biomass from forest and mill residue, agricultural and municipal waste (see Appendix B accompanying these comments). This waste is distributed in varying availability around the country, but the ability to average over the fleet would enable emissions rate reductions to be twice that that would be achieved only from operational and capital changes at plants at the same or less cost.

The system-level costs of a flexible approach to achieve heat rate improvements, without crediting for biomass co-firing, have been estimated in a couple of papers that incorporate the engineering opportunities expected to be available at individual plants, with the opportunity to change operation of the system to achieve further improvements on average. These papers (Burtraw, Woerman, and Paul 2012[3]; Burtraw and Woerman 2013[4]) examined a set of investments that were less substantial than a major overhaul of the turbine, and identified that the marginal cost of emissions reductions achieved through an average heat rate improvement of 4 to 5 percent in the coal fleet would cost about $10 to $30 per ton of carbon dioxide reduced. This is somewhat greater than the cost suggested by EPA but still reasonable when measured against the social cost of carbon emissions, as estimated by the Interagency Working Group. These reductions are measured against a future baseline for 2020; measured against the heat rates in 2012, the reduction would be nearly another percent according to the modeling, approaching the 6 percent target identified in building block #1.

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[2] Linn, Joshua, Erin Mastrangelo, and Dallas Burtraw. 2014. Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act. *Journal of the Association of Environmental and Resource Economists* 1(1/2). DOI: 10.1086/676038. http://www.jstor.org/stable/10.1086/676038

[3] Burtraw, Dallas, Matt Woerman, and Anthony Paul. 2012. Retail Electricity Price Savings from Compliance Flexibility in GHG Standards for Stationary Sources. *Energy Policy* 42: 67–77. http://www.sciencedirect.com/science/article/pii/S030142151100913X

[4] Burtraw, Dallas, and Matt Woerman. 2013. Technology Flexibility and Stringency for Greenhouse Gas Regulations. RFF Discussion Paper 13-24. Washington, DC: Resources for the Future. http://www.rff.org/Publications/Pages/PublicationDetails.aspx?PublicationID=22235

In conclusion, the evidence suggests EPA's finding that a 6 percent reduction in heat rate from 2012 levels is technically plausible and economically reasonable—given that the agency adopts a flexible approach to achieve compliance. The magnitude of the overall reduction in emissions rates could be twice this magnitude if co-firing with biomass were credited under a flexible system that allowed averaging across the fleet. It is reasonable to expect that the fuel that would be used would all be waste biomass, not requiring the introduction of new dedicated energy crops.

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Is it possible for existing natural gas power plants to increase average utilization to 70 percent (building block #2) and, if so, at what cost?

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This comment appeared originally as part of RFF's Expert Forum on EPA's Clean Power Plan on September 17, 2014. All responses in the forum are attached in their entirety in Appendix A.

Recent history suggests a dramatic change in capacity factor is very possible, but prior experience does not provide evidence that it would be sufficient to achieve the building block target of 70 percent on average for all gas plants. This seems much more plausible for relatively newer plants. Of course, EPA's proposed Clean Power Plan does not require this outcome for all plants or for any specific plant; rather it has to be sufficiently plausible to serve as a justification for the stringency of the proposal. The actual outcome could involve other changes in the electricity system, including investment in new facilities.

The national average capacity factor (utilization) for natural gas combined cycle plants (NGCCs) increased from 40 percent to 51 percent from 2008 to 2012, falling somewhat in 2013, and it is widely believed that additional shifting from coal to gas represents the lowest-cost option for reducing emissions from the power sector. In some regions, the change has been even more dramatic. For example, generation from natural gas in Pennsylvania increased by 58 percent between 2010 and 2012. EPA's Clean Power Plan suggests that existing NGCC units could increase their capacity factors to 70 percent on average.

To determine whether this is plausible, one can look at recent performance. Capacity factors across the gas fleet show a pattern of variation by vintage. Capacity factors of the oldest plants are a lot lower than for all other plants and are fairly insensitive to relative fuel prices. The price of gas fell by half from 2008 to 2012 but, between those years, the median capacity factor of the oldest group only increased from 20 to 25 percent.

By comparison, between 2008 and 2012, the median capacity factor of the group of plants installed between 2001 and 2003 increased from about 32 to 46 percent. There is less heterogeneity among the newer plants, but few existing plants currently operate at 70 percent utilization. Econometric analysis in progress by my colleagues Joshua Linn and Lucija Muehlenbachs finds that the capacity factor of larger and newer gas plants responds more to gas prices than the capacity factor of smaller and older gas plants.

Another feature of natural gas generation is the variation in use by time of day. Gas turbines are expected to run during times of peak electricity demand, but NGCC units are expected to run more evenly on a daily basis. Nonetheless, over the past decade the capacity factor for NGCC units varies by a factor of two between times when it is least and most in use, suggesting considerable room for continued utilization over all hours.

The significance of these findings is two-fold. On the one hand, the fact that the newer part of the fleet is more responsive to changes in gas prices suggests that greater utilization is plausible on a fairly widespread basis, as EPA has asserted. On the other hand, gas plants that went online prior to the early 1990s now account for a much lower share of total generation than before. Because these plants do not tend to be responsive to changes in gas prices, the cost of increasing the utilization of these plants would be high—perhaps due to the characteristics of the plants, their location in the electricity system, and the availability of gas supply or proximity to low-cost coal units. In this vein, greatly expanding the utilization of gas units at older plants could be more costly than what is revealed by recent trends for newer plants.

EPA should consider carefully whether incentives should be given for construction of new facilities by including them in the calculation of the demonstrated emissions rates. Scenario modeling at RFF suggests that the expansion of natural gas use might be most likely to occur through investment in new units, especially if the emissions rate for new gas units is below the target emissions rate. EPA's Clean Power Plan is ambiguous to some degree about the treatment of new plants. However, in the preamble, it appears that the emissions rate calculation is to be based only on existing units. In this case, there would be no additional incentive for new gas.

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Who should translate the states' assigned rate-based goals into mass-based goals—the states or EPA—and how?

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This comment appeared originally as part of RFF's Expert Forum on EPA's Clean Power Plan on September 5, 2014. All responses in the forum are attached in their entirety in Appendix A.

EPA should translate its rate-based goals into mass-based goals. It has already described, in broad terms, methods for states to make the translation, but the incentive for states to inflate their mass goals when translating is unavoidable. A single standardized method for translation written by EPA would clear up confusion and remove the inevitability of goal inflation if states do the translations themselves.

The premise for the translation is made clear by EPA. "The conversion must represent the tons of CO_2 emissions that are projected to be emitted by affected EGUs, *in the absence of emission standards* contained in the plan, if the *affected EGUs [electric generating units]* were to perform at an average lb CO_2/MWh rate equal to the rate-based goal." (Federal Register, Vol. 79[117]; 34953)

I've added the italics to emphasize the crucial parts of the statement. "In the absence of emissions standards" implies that we need a business-as-usual (BAU) projection of generation by affected EGUs. EPA already has deployed Integrated Planning Model (IPM) version 5.13 to project a Base Case for the power sector through 2030. The confusion arises from whom are the affected EGUs? EPA's formulation of the rate-based goals partly resolves the confusion. It is located on page 18 of the Goal Computation Technical Support Document.[5]

rate goal [lbs/MWh] =
emissions from existing fossil [lbs] /
(generation from existing fossil +
generation from at-risk nuclear +
generation from projected renewables +
projected demand savings from energy efficiency) [MWh]

A little algebra translates a rate goal to a mass goal. The denominator in the formula is projected generation from affected EGUs under BAU conditions plus projected energy efficiency. The product of the rate goal and the denominator is the mass goal.

The rate goal comes from EPA, but generation by affected EGUs must be produced by a model. Different models produce different projections, so allowing states to choose a model effectively invites them to manipulate the stringency of the rule. If they choose a model that projects a high level of generation then emissions will be higher and costs lower than if they choose one that projects less generation. EPA can simultaneously obviate this potential for manipulation and the burden they place on themselves to accept or reject the models chosen by the states if they employ a model themselves to project generation and make the rate-to-mass conversion.

The unresolved issue is whether states will include new generators in their compliance plans. Particularly salient are new natural gas combined-cycle and nuclear generators. Their inclusion in compliance plans is

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[5] US Environmental Protection Agency (EPA). 2014. Goal Computation Technical Support Document. Docket ID No. EPA-HQ-OAR-2013-0602. Washington, DC: US EPA Office of Air and Radiation. http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-goal-computation.pdf

left open for comment by EPA. If they are included in compliance plans then they need to be included in the translation.

To include new generators in the translation EPA would add projected generation from those sources into generation from affected EGUs, which is multiplied by the rate goal to get the mass goal. That amounts to increasing the mass goal, but simultaneously covering more sources. The total emissions and cost consequences of including new generators are not known ex-ante. They depend upon whether states adopt rate or mass goals.

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Accounting for the role of energy storage in compliance with the Clean Power Plan

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The Environmental Protection Agency (EPA) has asked for comment on its proposed Clean Power Plan that would regulate greenhouse gas emissions from existing power plants under Section 111(d) of the Clean Air Act. EPA Administrator Gina McCarthy has stressed the flexibility of the rule as well as the ability for cost-effective and innovative solutions to lower emissions, grow the economy, and reduce health impacts from greenhouse gases. Flexibility is also a crucial attribute for efficient operation of the electricity system. A major technological development that promises to expand the flexibility of the electricity system is the introduction of energy storage technology, including electric vehicles. We are writing to urge the agency to consider carefully the incentives for the development of energy storage that are implicit in the Clean Power Plan.

We offer specific recommendations for the agency's consideration.

1. Support the development of state plans that anticipate a role for energy storage.
2. Develop evaluation criteria that help states demonstrate the role that storage will play in the accelerated introduction of non-emitting technologies.
3. Require states to conduct ongoing monitoring and evaluation of the role of energy storage in their electricity systems and introduce corrective measures where possible.
4. Consider how emissions reductions in other sectors (such as transportation) might be facilitated by the introduction of technologies, such as electric vehicles.
5. Consider the calculation of net emissions changes, including changes in other sectors, in state plans.
6. Assist states in accounting for the potential role of electric vehicles in the determination of activity levels that are used in the transition from rate- to mass-based standards.

Energy storage is expected to play a growing role in the future evolution of the electricity grid. The nation's economy requires a robust and resilient electricity delivery system. Energy storage can play a significant role in meeting this goal by improving the operating capabilities of the grid, lowering cost, and ensuring reliability while deferring and reducing infrastructure investments overall. It can be instrumental for emergency preparedness by providing backup as well as grid stabilization services.

EPA's Clean Power Plan is designed to encourage a transformation of the electricity system to reduce greenhouse gas and other pollutant emissions. There are attributes of energy storage technology that may enable it to contribute to this transformation. However, energy storage also may facilitate the expanded use of incumbent technology, undermining the environmental goals of the Clean Power Plan. Therefore, the plan should anticipate the kind of incentives provided for the development of storage.

Conventionally, to meet the electricity demand, electricity suppliers would depend on instantaneous combustion of fossil fuels or use of other resources to create electricity when needed. Beyond the storage of fuels for electricity generation at various times of day, energy storage technology has traditionally been limited to the use of hydroelectric resources. Increasingly, a variety of economic forces and concerns over the environmental impacts of fossil fuel combustion are driving a shift toward greater use of renewable energy sources. Unlike fossil fuels, the temporal profiles of many renewable energy resources are often uncontrollable and the resources are available only intermittently. This poses a barrier to the introduction of renewable energy sources into the electricity system. Energy storage offers a potentially potent technology to accelerate the introduction of renewable technology by enabling the system to respond to intermittent supply.

If associated with renewable energy technology, the ability to store energy allows the electricity system to maximize the potential contribution of renewable energy output and synchronize the delivery of clean, emissions-free energy with the time when levels of electricity demand are greatest. Storage devices are already enabling wind farms in Texas and solar arrays in California to capture production in excess of contemporaneous demand and to deliver energy services when they are most highly valued. When there is an abundance of intermittent renewable energy, the available capacity to store excess renewable output provides an option to overcome the grid stability issues posed by the intermittency of renewable generation

Energy storage also could be used to support expanded use of fossil energy resources. Energy storage technologies can allow fossil fuel power plants to operate at peak efficiency. This could have associated environmental benefits, for example, if storage is used to avoid the need for conventional fossil-fired generation to respond to small changes and power fluctuations due to instantaneous variation in electricity demand or the intermittency of renewable generation.

However, energy storage may allow the greater utilization of low variable cost, baseload fossil-fired generation, which typically is relatively high emitting generation. Where there is excess supply of baseload fossil generation over some hours of the year, storage would enable that supply to be brought into or kept in service, and thereby spawn negative environmental outcomes. Further, this could lead to a reduction in the average system cost, thereby enabling an expansion in the demand for energy services, amplifying this outcome.

Under the Clean Power Plan, states will be required to develop plans that demonstrate that the state's affected entities will achieve the state's emissions performance level. Energy storage may play a role in that demonstration. In order to facilitate the transformation in the electricity system envisioned in the Clean Power Plan, EPA should give careful consideration and credit for energy storage where states include storage as a technology to help achieve compliance. State plans that provide incentives for the expansion of storage should be considered favorably. However, as indicated, storage could enable positive or negative environmental outcomes. The nature of the storage technology and how it is located and integrated in the system will provide evidence about the type of services it provides. Therefore the identification of milestones and monitoring and reporting should be implemented if storage is given a role in state plans. Where storage goals are not achieved or where storage does not reinforce the attainment of desired environmental outcomes, corrective measures should be implemented.

One potentially important point related to the role for storage is the way states choose to implement the Clean Power Plan. Under the plan, states are given the option to convert from an emissions rate standard to a mass standard, introducing effectively an emissions budget. This choice could have an indirect, but potentially significant, negative effect on the introduction of electric vehicles, which are inherently energy storage devices.

EPA is seeking comment on how states might convert their rate-based targets to mass-based emissions budgets. Technical guidance from EPA suggests that a forecast of activity levels (electricity demand) be used for that conversion. Once a forecast is adopted, any incremental use of electricity that might be enabled due to energy storage technology would face an economic penalty imposed by a mass-based emissions budget. Specifically, the expanded use of electric vehicles would lead to an increase in demand for electricity generation. If this is not anticipated in the conversion to a mass-based standard, such a

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standard could introduce an unanticipated cost on electric vehicles due to the increased cost of environmental compliance that comes with increased electricity demand. Ideally, if there were a concomitant increase in renewable technology to meet the demand of electric vehicles, the problem would be solved. However, in the near term, when electric vehicle technology and the infrastructure that will be necessary to support its widespread adoption are still in development, the constraint on emissions in the electricity sector could pose a cost disadvantage that might hobble the emerging industry. In addition, under either a rate-based or a mass-based system, due to the sector-based nature of the Clean Power Plan, the emissions reductions that might be achieved in the transportation sector would not be accounted for as an advantage of electric vehicle use.

In summary, how energy storage will be used in the future will be influenced strongly by the requirements and implementation of the Clean Power Plan. In general, storage can enable a more efficient balance of supply and demand and smooth out the peaks and valleys that currently challenge grid operators. By regulating electricity generation, storage can mitigate peaks in electricity price and lower the average electricity price. It can empower a more responsive and reliable grid–power system. It can also be used to mitigate the environmental and public health impacts of pollutant emissions profiles. Most importantly, energy storage, including the inherent storage function of electric vehicles, can greatly expand the role for renewable energy technology to meet the nation's electricity demands. However, without investment in renewable energy, energy storage could have negative environmental and health impacts by enabling greater use of fossil fuel generation. Consideration of these potentially beneficial and potentially adverse effects should be given by states and EPA in the development of state plans.

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Should EPA allow states to use a carbon tax to comply with the Clean Power Plan, and if so, how could the carbon reduction effects of the tax be demonstrated?

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This comment appeared originally as part of RFF's Expert Forum on EPA's Clean Power Plan on November 11, 2014. All responses in the forum are attached in their entirety in Appendix A.

EPA should provide states with the option of using a carbon tax to comply with the Clean Power Plan, but it needs to be careful about how that option is implemented. Allowing a carbon tax fits well with the general approach of giving states a variety of compliance options; each state can pick the approach that works best for its individual needs. And carbon taxes have several important advantages over other compliance options. But the translation from emissions rate–based goals to tax rates is important and needs to be structured to limit states' incentives to pass other policies that undermine the effectiveness of the carbon tax.

Economists have long recognized the close similarities between a carbon tax and a cap-and-trade system—both put a price on carbon while offering flexibility in how to reduce emissions. EPA's Clean Power Plan allows cap and trade as a compliance option, so it is natural to allow carbon taxes as well.

Moreover, a carbon tax has a number of substantial advantages. It provides a stable and predictable carbon price, which reduces uncertainty, making decisions about emissions-reducing investments simpler. That stable price also avoids any potential for market manipulation. Carbon taxes are also easier to administer than an emissions trading system and they could accomplish the added benefit of providing revenue for state budgets. Coordinating carbon tax rates across states is also simpler than setting up a multi-state trading system. Of course, carbon taxes have disadvantages too, and won't be right for every state—but the advantages are sufficient to justify making the option available.

However, EPA needs to be careful about how that option is implemented. A key question is how to translate emissions rate–based state goals into a tax rate. In most respects, this is relatively straightforward. It requires careful modeling to estimate what tax rate is equivalent to any given emissions rate, but the same is true for converting between rate-based and mass-based goals. The models won't always be right, of course, but they don't need to be; as long as they're correct on average (that is, unbiased), the carbon tax will have the same long-run effect on emissions as the equivalent rate-based approach. To guarantee unbiased modeling, EPA will either need to do that modeling itself or impose clear standards for how it needs to be done—but again, the same issue arises for converting to mass-based goals.

An important difference, though, is that a state that doesn't want to regulate carbon could take actions to undermine the effectiveness of a carbon tax—something that would be far more difficult under a cap-and-trade or traditional regulatory system. For example, suppose such a state chose to impose a carbon tax, but then used the tax revenue to subsidize fossil fuels (or a less-obvious policy with a similar effect), thus undoing the effect of the carbon tax. Economists refer to this as "fiscal cushioning." To prevent this, modeling to determine the tax-rate target will need to take into account any other state policies that have a substantial effect on carbon emissions—and might need to be updated if those other policies change.

Combining coal and gas into a single source category to reduce barriers to emissions trading

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Earlier this year, I submitted comments regarding EPA's proposed new source performance standards for greenhouse gas emissions from the electric power sector (Docket Number EPA-HQ-OAR-2013-0495). In these comments, which are excerpted below and attached as Appendix C, I argued that EPA should combine coal and gas electric generating units (EGUs) into a single source category for purposes of those proposed standards.

The primary justification for doing so was to reduce or eliminate legal barriers to emissions trading between sources in the two categories. Such trading was not proposed in the context of new-source standards, but is crucial to the success of existing-source standards, as recognized by building block 2 of EPA's current proposal. EPA's approach to source category definitions remains unclear in both the new- and existing-source proposals, with the agency "co-proposing" merged and split categories.

I urge EPA to use its broad legal authority under §111(b) to revise source category definitions and merge all EGUs subject to new and existing-source greenhouse gas performance standards into a single source category, and to do so in consistent fashion across the two rulemakings. Only EPA has authority to revise source category definitions—states implementing existing source standards cannot avoid the legal risks associated with trading across source categories.

Key points from the RFF issue brief:
Preserving Flexibility: Comments on the US Environmental Protection Agency's Carbon Existing Source Performance Standards[6]

- The US Environmental Protection Agency's decision to separate coal and gas power plants into different regulatory categories for its proposed New Source Performance Standards (NSPS) has little effect on those standards, but has important implications for upcoming existing-source standards (ESPS).
- The approach—split or combined categories—that the agency uses for its NSPS will almost certainly persist for ESPS.
- Other research indicates that switching from coal to gas generation is the largest and lowest-cost emissions reduction opportunity in the power sector.
- Combined categories are therefore crucial to the cost- and environmental effectiveness of ESPS. Trading between coal and gas that could incentivize this fuel switching is almost certainly legal if categories are combined, and almost certainly illegal if they are not.
- Combining coal and gas into a single category, as the agency did in its first NSPS proposal in 2012, would not reduce EPA's freedom to set standards, increase the rule's complexity, or add any significant legal risk.
- EPA should therefore combine coal and gas into a single source category in its final NSPS rulemaking.

[6] Richardson, Nathan. 2014. Preserving Flexibility: Comments on the US Environmental Protection Agency's Carbon Existing Source Performance Standards. RFF Issue brief 14-05. Washington, DC: Resources for the Future. http://www.rff.org/Publications/Pages/PublicationDetails.aspx?PublicationID=22369.

Comments on the role of end-use energy efficiency in EPA's Clean Power Plan

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End use energy efficiency plays multiple roles in EPA's Clean Power Plan as both the basis for the fourth building block of the BSER and as a potential component of a state's plan for compliance with its emissions rate standard. This comment addresses both roles.

Energy Efficiency in Building Block 4

The purpose of EPA's building block 4 is to define the electricity generation savings that states could achieve through energy efficiency programs and incorporate those potential savings into the emissions rate target calculation as a non-emitting energy resource similar to wind or solar power. The higher the energy savings potential, the tighter the state's emissions rate obligation under the Clean Power Plan policy, all else equal.

EPA bases its calculations on existing state policies: 24 states have adopted Energy Efficiency Resource Standards (EERS) that target a specific minimum ratio of efficiency program–related energy savings to total electricity consumption. Twelve of those states have EERS policies that require or soon will require a 1.5 percent incremental reduction in total statewide electricity consumption each year and that is the target that EPA adopts in its proposed Building Block 4. For states that are net importers of electricity, savings targets are adjusted downward by the fraction of electricity consumed in the state that is generated within the state for purposes of augmenting the denominator in the emissions rate target; states that are net power exporters can claim the full amount of energy consumption savings in their target calculation. States that have no or limited experience with EERS policies or efficiency programs more generally are given time to ramp up to the ultimate 1.5 percent annual energy savings goal in calculating the building block four contribution to their state target.

The approach that EPA takes raises a couple of questions about the cost-effectiveness of this particular building block.

First, states with ambitious existing energy efficiency programs tend to have a larger obligation than states where energy efficiency policies are less advanced. The effect of such differentiation across states on cost-effectiveness from a national perspective is an open question. One might expect there to be more low-cost opportunities for saving energy in the inexperienced states where energy-using equipment and building stocks are presumably less efficient than in the more experienced states. But it could also be the case that more experience with running energy efficiency programs results in learning by doing and greater future energy savings at lower cost. Or both factors could be at play simultaneously with the ultimate answer depending on the balance between the two.

Second, state-level targets under building block 4 are not differentiated based on the potential for associated carbon reductions. Indeed, states with some of the highest building block 4 requirements, including Maine, California, and Connecticut, have some of the lowest historic CO_2 emissions rates. In contrast, some high emitting states, including Wyoming and West Virginia, have some of the lowest efficiency potentials. (This latter observation is not surprising as high emissions rates tend to be correlated with low electricity prices and thus weak economic incentives to encourage energy savings through investments in efficiency, setting aside environmental arguments for such investments.) Across the 50 states, there is a small negative correlation between efficiency potential and average CO_2 emissions rates in 2012. This lack of correlation raises a question of whether a more targeted approach would improve both the effectiveness and cost-effectiveness of this building block.

Energy Efficiency and State Compliance Plans

Consistent with the construction of building block 4, states are allowed to include energy efficiency programs in their plans for complying with the EPA Clean Power Plan guidelines. Because, unlike generation or CO_2 emissions, energy savings are impossible to meter or measure with a device—and so one of the most important issues in this context is evaluation, measurement, and verification (EM&V) of energy savings that result from efforts to promote energy efficiency. EPA has indicated in section VIII.F.4 of the proposed rule that it intends to develop guidance for EM&V of demand-side energy efficiency programs and measures incorporated in state plans.

The role of EM&V in verifying ultimate compliance depends on whether a state chooses to convert its emissions rate target (tons CO_2 per MWh of electricity generation) to a mass budget (tons CO_2). If a state adopts a mass-based target, CO_2 emissions from covered generators can be measured directly and evaluating compliance with the rule is straightforward and quite separate from evaluating the savings from efficiency programs that may be adopted as a "complementary" policy (identified as such because it contributes to reducing the demand for emissions allowances.[7]) If a state opts instead to stick with EPA's emissions *rate* target, then its compliance is assessed by the level of its adjusted CO_2 emissions rate target, which roughly corresponds to CO_2 emissions divided by the sum of generation by existing fossil, at risk and new nuclear, non-hydro renewables, and energy savings from energy efficiency programs. Under this formulation of the standard, savings have a direct impact on a state's compliance; EM&V of those savings is arguably more important.

The first thing states have to do is submit a compliance plan. If that plan implements an emissions-rate target and relies on energy efficiency programs to reduce emissions, the plan needs to both identify expected energy savings and convert those savings into emissions reductions. EPA has developed tools for doing this conversion that states may choose to employ. For ultimate compliance purposes (after the fact), it is the measurement of energy savings that is more important; the emissions component (the numerator) of the actual emissions rate is observable, but energy savings, which are part of the denominator, are not. The greater the savings that are claimed from energy efficiency, the less work a state has to do to address CO_2 emissions directly. A robust method for evaluating savings will reduce the likelihood that phantom energy savings play a role in compliance.

Thus, states that choose to use energy efficiency for compliance need to develop and provide EPA with a plan for evaluating energy savings that result from the policy. A substantial challenge for implementation of an emissions rate target under the Clean Power Plan is that state approaches to EM&V differ; in fact they may differ among utilities within a state. Although there is disagreement about whether these practices are rigorous, anecdotally one finds a widespread viewpoint among utilities and states that run these programs that their EM&V are of high quality. Issues of EM&V quality aside, these differences in approach across entities pose a challenge for states that engage in interstate emissions rate averaging or credit trading. Differences in EM&V practices for energy efficiency set the stage for litigation among the many parties that would have standing if credits flow across states. Parties in one state may feel unfairly disadvantaged if another state uses an inferior, or in any case different, approach to measuring the contribution of programmatic energy efficiency. Agencies and stakeholders in the states have invested substantial efforts to develop their individual approaches to EM&V, but the difference in those approaches is a potential hazard for the Clean Power Plan. Hence, EPA may need to impose strong

[7] Note that in a strict economics terminology sense, such a policy would be a substitute for an emissions cap and not a complement as it reduces demand for emissions allowances instead of raising it (Brennan 2012).

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guidance on EM&V practices. Otherwise, the difference in EM&V practices may provide an incentive to convert to a mass-based approach to avoid this legal risk.

In the technical support document for state plans, EPA describes the state-of-the-art with respect to EM&V of energy efficiency programs and suggests a number of approaches that states might adopt.

EPA's discussion of EM&V focuses on traditional engineering-based methods. These calculations are sometimes (but not always) adjusted to reflect the fact that some of the consumers who participate in an efficiency program may have made the investments anyway. When they are made, adjustments are based on surveys that ask customers whether they would have invested without the program, a method of questionable reliability. The engineering approaches also may fail to account for the interactions between efficiency enhancements related to one end use and energy consumption for another end use. (For example, replacing incandescent lights with cooler compact fluorescent lights or LED lamps could increase demand for energy for heating in the winter and reduce demand for energy for cooling in the summer.) They also fail to account for the so-called rebound effect, an increase in usage that may occur when efficiency improves. And the engineering approach is not well suited to policies that work through behavioral "nudges," information provision, and other non-technology based approaches.

Going forward, EPA should encourage states to incorporate more robust evaluation methods into efficiency program designs if these programs are to play a role in their state plans under the Clean Power Plan. Such methods include more use of randomized control trials or quasi-experimental methods as described in and recommended by the SEE Action report, titled *Evaluation, Measurement, and Verification (EM&V) of Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations*.[8] While this report is focused on evaluation of behavioral programs, all efficiency programs have a behavioral aspect to them and current evaluation approaches do not tend to address it very well. Empirical approaches use actual customer-level energy consumption data, comparing energy consumption before and after a policy takes effect for those affected by the policy and also a control group. The empirical approach also eliminates the need for a separate net-to-gross calculation and it automatically accounts for impacts of the efficiency policy across different energy end uses. The approach can be used for nudges, information provision, and similar policies. This econometrics approach is often used in the scholarly economics literature, but typically has not found its way into mainstream energy efficiency EM&V.

Development of compliance plans for the Clean Power Plan provides an opportunity for states and utilities to experiment with these more robust evaluation methods. Given the decade long compliance period that starts in 2020, a little more than 5 years from now, there is time for utilities and states to experiment with new evaluation methods. As these experiments unfold, we can start to build a base of knowledge that will enable better forecasts of future energy savings and energy efficiency potential, better targeting of energy efficiency resources, and ultimately more cost-effective policies for saving energy and reducing carbon emissions.

This type of empirical analysis can be challenging to do because identifying a relevant control group can be a challenge and access to customer level data is hard to come by. However, neither challenge is insurmountable.

[8] State and Local Energy Efficiency Action Network. 2012. *Evaluation, Measurement, and Verification (EM&V) of Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations*, report of the Customer Information and Behavior Working Group and Evaluation, Measurement, and Verification Working Group, May.

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One way to solve the first challenge is to randomly assign customers to the energy efficiency intervention. This is the approach that is taken in the Home Energy Report[9] program (operated by OPower). Under this program, electric utilities sign up to have OPower send randomly selected customers reports on their home energy use and how it compares with that of other similar households. When energy consumption before and after receiving a report (for households that receive the report) is compared to the change in energy consumption for households in the control group, studies by Allcott[10] and Ayres et al.[11], find that simply providing the reports produces a roughly one to two percent reduction in energy use. Randomized control trials are typically used to analyze the efficacy of new drugs, but they have also been used extensively for policy evaluation in the areas of education and poverty alleviation and others have advocated for greater use of this experimental approach for energy efficiency program evaluation[12].

When random assignment is impossible, another approach would be to provide a randomly selected group of customers extra encouragement to participate in an energy efficiency program and then make similar comparisons in energy use before and after the program takes effect between affected and encouraged customers and others.

A third approach would be to build in eligibility requirements for program participation (limited time offers, limited program budget, size thresholds for eligibility) that provide a quasi-experimental dimension and facilitate the creation of a good control group. With sufficient customer-level data, such as that used by Lucas Davis, Alan Fuchs and Paul Gertler[13] in their study of the Mexican Cash for Coolers program, customers participating in an efficiency program can be matched with closely associated control households for clean identification of the policy's effect.

The second challenge of obtaining access to customer-level energy bill data is a longstanding one. It reflects utility and customer concerns about customer privacy that have increased with the widespread introduction of smart meters which collect a large amount of data on real time energy use. However, this concern could be addressed by regulators requiring utilities to make data available to evaluators and researchers under strict non-disclosure agreements and privacy protections. Economics researchers who are experts in using these methods have experience with such agreements and have procedures for protecting data confidentiality. Adhering to these practices and procedures is in the researchers' interests because they are always looking to the next research project and getting access to the next data set will require good stewardship of the current one.

The types of evaluations discussed here would provide a cleaner and more robust picture of the net effects of efficiency policies and programs on overall customer energy use in homes and commercial buildings than we currently have. Impacts measured using these approaches provide a better basis for assessing the CO_2 emissions reductions that actually result from efficiency interventions and that might be expected in the future. Using state of the art approaches to evaluating efficiency policies is an essential ingredient to finding the most effective and cost effective approaches to reducing energy consumption and CO_2 emissions.

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[9] http://opower.com/platform/computer-science

[10] Allcott, Hunt. 2011. Social Norms and Energy Conservation. *Journal of Public Economics* 95: 1082–1095.

[11] Ayres, Ian, Sophie Raseman and Alice Shih. 2013. Evidence from Two Large Field Experiments that Peer Comparison Feedback Can Reduce Residential Energy Usage. *Journal of Law, Economics and Organization.*

[12] Vine, Edward, Michael Sullivan, Loren Lutzenhiser, Carl Blumstein and Bill Miller. 2014. Experimentation and the evaluation of energy efficiency programs. *Energy Efficiency*.

[13] Lucas, Davis, Alan Fuchs and Paul Gertler. 2014. Cash for Coolers: Evaluating a Large-Scale Appliance Replacement Program in Mexico. *American Economic Journal: Policy* 6(4): 207–238.

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Addressing the Possibility of Emissions Leakage in the Clean Power Plan

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The term "leakage" describes the movement of economic activity, electricity generation or emissions across jurisdictional borders in response to a change in prices or incentives that accompany the regulation of carbon dioxide (CO_2) emissions. Even if there were no change in emissions, a shift in economic activity could have undesirable consequences from the perspective of at least one of the affected jurisdictions. However, the central issue with respect to implementation of the Clean Power Plan and the one that we focus on is the effect on emissions.

Leakage may occur because of the interaction between a state that uses a mass-based standard and one that uses a rate-based standard. If emissions in one jurisdiction are capped, but not capped in the neighboring jurisdiction, then incentives exist for a shift in the operation of existing generation resources and investment in new resources to the jurisdiction that does not cap emissions. As a consequence, total emissions of CO_2 would be expected to increase, along with emissions of co-pollutants including sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Similarly, if two jurisdictions have different emissions rate standards, incentives may exist to shift generation and investment to the jurisdiction with a less stringent standard. The shift may lead to the utilization of different fuels and technologies, leading to an increase in emissions of CO_2 and changes in the location and magnitude of SO_2 and NO_x.

We have conducted detailed modeling to simulate the operation of the electricity system and investment and retirement of generation capacity over a 25 year horizon, using the Haiku electricity market model, developed and maintained by Resources for the Future. We have explored a large number of potential emissions rate trading programs with states coordinating in various regional configurations, we have examined the translation of emissions rate standards into emission cap and trade programs, and we have examined the relation between emissions rate and cap and trade programs and emissions rate targets of varying stringencies in neighboring jurisdictions.

We find opportunities for potentially significant emissions leakage. However, we also find factors and policy options that serve to mitigate or entirely eliminate leakage. These comments summarize our findings and provide guidance to EPA in development of a final rule. First we present recommendations. Second we offer background on the origin of concern about emissions leakage and assessments of the potential magnitude of leakage. An important observation is that in some cases the expectation of potential leakage based solely on differences in emissions rate standards might be exaggerated. We describe some key results from recent research that support these recommendations.

Recommendations

1. <u>State compliance plans should address how their compliance activities affect and interact with neighboring states.</u> One bell-weather interaction among states is the expected change in the net electricity imports to a state. Simulation modeling can provide quantitative insights into this measure. Modeling would involve explicit assumptions about the scope and structure of compliance activities in neighboring states. A group of states may cooperatively share this information to provide a basis for evaluation. In the absence of such information, there are a limited number of obvious scenarios that go far towards spanning the possible choices that neighboring states might pursue and these could be addressed in the state plan. For instance, neighboring states might:

- Comply with assigned emissions rate targets
- Participate in a regional emissions rate averaging program involving neighbors within the relevant power market
- Convert assigned emission rate targets into state-specific emissions caps
- Convert assigned emission rate targets to caps and join a regional cap-and-trade program.

If a quantitative evaluation is not practical, a qualitative and analytical evaluation might be sufficient. The evaluation should consider the incentives and expected outcomes of its own chosen compliance activity in the context of its neighbors announced plans, or in a set of contexts as described above.

2. <u>State plans should address how their activities affect the attainment of National Ambient Air Quality Standards in neighboring states.</u> Section 111 of the Clean Air Act directs EPA and states to take into account the environmental outcomes of their compliance activities. The Clean Air Act's good neighbor provision provides a specific basis for taking the effect of emissions on one's neighbors into account in a planning process.

3. <u>EPA should consider requiring additional compliance obligations of states where there may occur substantial changes in inter-state electricity transmissions due to compliance activities.</u> Three possible approaches include:
    - If a state increases its net electricity exports by more than 10 percent from a base year period the emissions rate standard that should apply to the associated incremental increase in electricity generation should be <u>the more stringent of the state's standard or the average standard in the state's power region</u>.
    - States might be required to hold <u>electricity transfer credits for electricity imports</u> or exports that are greater than those observed in a base year period.
    - State's might be required to <u>adjust the emissions rate calculation that is applied within their states compliance plan to provide incentives for greater utilization of low or non-emitting resources</u> so that there is no increase in total emissions.

4. <u>In order to minimize emissions leakage, EPA should further evaluate and potentially adjust the emissions rate targets assigned to states according to their relative production incentives.</u> The production incentive implicit is implicit in the emissions rate target. As described below, this incentive is a function of the target and the equilibrium price of emissions credits (the marginal cost per ton of emissions reductions). EPA modeling can identify the equilibrium value of emissions credits in each state. To mitigate leakage the state standards could be calibrated to achieve greater conformity in the production incentive within a region or across the nation.

5. <u>In states that use emissions caps for compliance the state plans should be required to assess the possibility for leakage in a regional context. States should evaluate and consider the use of output based allocation to the extent necessary to mitigate leakage.</u> States should consider the effect with respect to both the utilization of existing resources and investment. States that translate their emissions rate standards to emissions caps have the possibility of reintroducing a production incentive analogous to that which occurs under an emissions rate standard through the use of updating output based allocation of emissions allowances. Our research finds this is a potent

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solution to the leakage problem when capped states border with states that have emissions rate standards. The eligible sources could include all resources or only new generating units or it can be limited to low and non-emitting generation technologies including end use energy efficiency.

Background

There are two differences between an emissions rate standard and the generic approach to emissions cap and trade. One is that an emissions rate standard does not limit total emissions. The second is that an emissions rate standard introduces an incentive for production that is usually not an element of cap and trade. The production incentive is incumbent in the rate-based standard because the standard defines the emissions rate at which emissions can occur without an additional regulatory cost. The firm earns emissions credits per unit of production (tons per MWh) at the rate described in the standard. A higher standard implies a greater number of emissions per MWh can occur without an additional regulatory cost; a lower standard implies a smaller number. If a facility's emissions rate is greater than the standard, the facility has a net obligation or liability for the *difference* between its observed performance and the standard. If the facility's emissions rate is less than the standard, the facility has a net credit. In contrast, in a generic cap and trade program the regulated entity has to obtain emissions allowances sufficient to cover *all* of its emissions; hence there is no analogous production incentive.

The possibility for production incentives to differ among jurisdictions can result from different emissions rate standards. Differences in emissions rate standards may provide advantage or disadvantage to electricity generation in one state relative to another state in the same electricity market. That difference could lead to a geographic shift in the location of generation resulting in leakage and a possible increase in emissions of CO_2, SO_2 and $NO_{x.}$

The extreme case might be a generic emissions cap and trade program that does not have a production incentive. In effect, the emissions rate standard in this case is zero; a facility must account for all of its emissions, for example, if emissions allowances are distributed through an auction then facilities must purchase their allowances. Even if a cap and trade program distributes emissions allowances for free, as was the practice under the Title IV Acid Rain Program, there typically does not exist a production incentive because the volume of allowances distributed to facilities did not depend on its generation activity.

The consideration of two cases is helpful for analyzing the scope of potential leakage due to different compliance activities in neighboring states. One is the difference in emissions rate standards among states, and the second is the interaction of emissions rate standards and emissions cap and trade programs in neighboring states.

Differences in Emissions Rate Standards with Electricity Markets

We indicated above that differences in an emissions rate standard may provide relative advantages or disadvantages. One might anticipate that a region with a higher emissions rate standard would provide a greater production incentive than a region with a lower standard. In the context of the Clean Power Plan and regional electricity markets, we continue to expect this to be true but the advantage is not as great as one would anticipate from a direct comparison of emissions rate standards.

Units with an emissions rate below the standard receive a net positive incentive per unit of electricity generation, but the economic value of the production incentive is the *product* of a quantity and a price. The quantity measure is the difference in emissions rate from the standard, and the price is the value of emissions credits in the relevant market.

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Because a lower emissions rate standard is a more stringent standard, it may be associated with a higher price reflecting the marginal cost of emissions rate reductions. In contrast a higher standard can be viewed as less stringent and would be expected to have a lower price. This relationship will tend to make the difference in the economic value of the production incentive less than is apparent when looking at the difference in emissions rate standards outside of market equilibrium.

For example, consider the case of a facility with an emissions rate that is below the standard, so the net production subsidy is positive. The net production incentive (PI) per megawatt-hour of electricity generation is $PI = (q_s - q_f) * p$, where q_s is the emissions rate standard (tons/MWh), q_f is the emissions rate of the regulated facility, and p is the equilibrium price of transferable emissions rate credits ($/ton). For a given composition of generation resources, a more stringent standard would lower q_s and reduce the value of the first term $(q_s - q_f)$. This should lead to a higher marginal cost of emissions reductions in the region and therefore a higher equilibrium price (p). Consequently, the sign of the change in the net production subsidy for a change in the level of the standard is ambiguous, it could be positive or negative, but it is predictably less in percentage terms than the change in the standard.

We conducted simulation modeling that included a characteristic representation of states, with compliance at a regional level. We find that typically the change in PI for a change in q_s is positive. However, the percentage change in PI is less than the percentage change in q_s. In effect, the equilibrium outcome in a flexible compliance market nested within a regional electricity market mitigates somewhat the difference in emissions rate standards. The incentive for leakage that is introduced by a difference in rates is less than would be apparent from consideration of the emission rate standard differences without consideration of how those differences are propagated into a production subsidy in an equilibrium context.

In the example illustrated in Table 1, we show results from a solution to the Haiku model where we approximately matched the six regions identified in EPA's modeling. Each region has a weighted average emissions rate based on the targets assigned to the states in each region. There is joint compliance within each region, but not between regions.

The New England region in Table 1 is an outlier because its standard is below that which would be obtained by a new natural gas combined cycle facility. Nonetheless the region illustrates that the standard and credit price interact to create a production incentive. Leaving this region aside, the region with the highest rate standard (Midwest) is the one with the greatest production incentive but the difference between it and the next region (Mid-Atlantic) is mitigated by the credit price. Conversely, the region with the lowest standard (Southwest Central) does not have the least production incentive (which occurs in the West). The change in interregional net exports generally goes along with the expectation that regions with greater rate standards have an incentive to expand generation, which is aligned only approximately with the difference in the production incentive because the change in net exports also depends on the geographic relationship of the regions and the availability of transmission capability and generation capacity in the region. It does not follow the credit price by itself. With the exception of the New England, the distribution of the production incentive appears tighter than the distribution of rate standards.

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Regions	Rate Standard (lbs/MWh)	Credit Price ($/ton)	Production Incentive ($/MWh)	Change in Net Exports from Reference Case (TWh)
New England	726	65.2	23.7	-7
Mid-Atlantic	1345	24.9	16.7	+41
Midwest	1540	23.4	18.0	+30
Southeast	1095	25.8	14.2	-14
Southwest Central	881	33.5	14.7	-46
West	952	28.2	13.4	-6
Nation	**1137**	**28.6**	**16.3**	**-2**

Table 1: The equilibrium value of the production incentive under an emissions rate standard

In consideration of the process that EPA employed to develop emissions rate standards on a state-by-state basis, it makes intuitive sense that the difference in the production incentive among states is smaller than the difference in the emissions rate standards. The standards are determined on the basis of available resources in each state and region. States with a higher standard have higher-emitting resources among their incumbent generation fleet. Although it is not necessarily the case, these states might be expected to have relatively greater options to utilize and develop lower-emitting generation and energy efficiency than states where those resources are more developed already. Intuition suggests that states with higher emissions rate standards might have lower marginal abatement costs, which would be reflected in lower equilibrium prices for tradable credits. Table 1 indicates this is also what we observe in simulation modeling.

One implication is that looking at just the differences in emissions rate standards is suggestive of differences in a net production subsidy and consequently of leakage of emissions, but it is likely to exaggerate the effects that actually emerge in an equilibrium context. Other factors that also will mitigate the amount of leakage that will actually emerge include limitations on transmission capability between states and regions (which is represented in our modeling), and local congestion in transmission and distribution systems that require utilization of specific resources because of their location in the electricity grid (which is not represented in our modeling). Failing to account for these factors will lead to exaggerated estimates of the potential for emissions leakage.

Aligning the Marginal Production Incentive Across Regions to Minimize Leakage

The goal of minimizing leakage in order to ensure the desired emissions outcome of the Clean Power Plan comes into conflict with the goal of minimizing the cost of a given level of emissions reductions. If an emissions rate standard is used, a uniform national emissions rate standard with a single national credit price and single production incentive is expected to achieve the greatest emissions reductions at least cost. However, this could be expected to result in substantial shifts of generation and differences in total costs across regions. In contrast, the Clean Power Plan instead identifies demonstrated technical opportunities to improve efficiency and reduce emissions on a state basis and uses this information to identify state-specific emissions rate standards. The difference in standards introduces the possibility for unintended shifts in generation and increases in emissions. However, the proposed Clean Power Plan does not anticipate these shifts and consequently the emissions reduction goals may not be achieved and emissions leakage may result. Moreover, this leakage undermines the implementation of demonstrated technological opportunities identified in the Clean Power Plan.

EPA could preserve the technical basis for state-specific emissions rate standards and improve on the attainment of demonstrated technical opportunities by accounting for the market equilibrium context in which these technologies operate. This would be done by adjusting standards to more closely equate equilibrium production incentives. As noted previously, the production incentive is a function of the standard and the credit price. A uniform credit price would effectively introduce an efficient outcome with the greatest emissions reductions at least overall cost and the same marginal cost of emissions reductions in all regions, but it would lead to different emissions rate outcomes in different regions and leakage.[14] The emissions rate standards could be adjusted to more closely align the production incentives, accounting for credit prices that vary by region, to lessen the amount of emissions and generation leakage that would occur. The outcome would be less efficient than if a uniform credit price were in place, but it would balance the different technical opportunities that exist with the goal to minimize shifts in generation and leakage across regions.

Interaction of Emissions Caps and Emissions Rate Standards within Electricity Markets

An emissions cap typically does not include a production incentive unless one is built into the program by design. One way this can be accomplished is through the allocation of emissions allowances on the basis of economic activity, which in the context of the Clean Power Plan is electricity generation. To provide a production incentive, the measure of activity should be the current or a recent period, which is why this approach is described as output based allocation with updating.

We have conducted simulation modeling of a variety of configurations of potential cap and trade programs with neighboring emissions rate programs. We find the possibility for leakage is significant. For example, in one scenario using an older version of the model we imagined compliance with the Clean Power Plan in which the entire nation had a uniform emissions rate trading program that allowed averaging of emissions rates across the remaining states. We use the term "uniform" to describe an emissions rate that was calculated as the weighted average of rates assigned to individual states.

We compared this scenario to one in which the nation was divided into four regions. States in three regions, (northeast, upper Midwest and California) had translated their emissions rate standards to caps and formed cap and trade programs. There was no trading between these programs, only within them. Emissions allowance value was returned to ratepayers through the local distribution companies in these simulations, thereby offsetting the increase in retail prices that would be expected. The rest of the nation was characterized by a uniform emissions rate trading program for the states in that region. We found that by translating emissions rates to caps in the three capped regions, electricity generation and emissions shifted to the rest of the nation, and *one-eighth* (12.5 percent) of the emissions reductions that were achieved under the national emissions rate trading program were eroded.

We contrasted this approach with one where the three cap-and-trade regions directed the value of emissions allowances to a production incentive implemented with updating output based allocation for all fossil units. The remedy was 100 percent effective. The production incentive in the capped regions offset the incentive to increase generation in the rate-based regions, eliminating leakage. Although there were slight shifts in generation that occurred between this model and the one with a national uniform emissions rate standard, total CO_2 emissions were nearly identical.

We replicated this experiment in an updated version of the model with the six regions listed in Table 1, organized to approximate regions in EPA's modeling of the Clean Power Plan. We first solved the model

[14] Burtraw, Dallas, and Matt Woerman. 2013. Technology Flexibility and Stringency for Greenhouse Gas Regulations. RFF Discussion Paper 13-24. Washington, DC: Resources for the Future. http://www.rff.org/Publications/Pages/PublicationDetails.aspx?PublicationID=22235

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with six independent emissions rate trading programs, achieving emissions reductions that were proximate to that predicted by EPA. We solved it a second time after converting two regions, the upper Midwest and the northeast, into cap and trade programs with the caps determined by the emissions observed in the first model. Allocation of emissions allowances was to ratepayers through local distribution companies. We found the second model with two capped regions eroded *one twelfth* (8 percent) of the emissions reductions that were achieved in the first model with the six regions using independent emissions rate trading. The erosion occurred because of leakage of electricity generation from the capped regions to the rate-based regions, with an associated increase in emissions.

We again contrasted this approach with one where the two cap-and-trade regions directed the value of emissions allowances to updating output based allocation for all covered units.[15] Again, the remedy was nearly perfect in returning emissions to the level anticipated in the Clean Power Plan when modeled with regional emissions rate trading.

Some states may prefer to direct allowance value to energy efficiency rather than to promote electricity generation. The Clean Power Plan treats energy efficiency as a non-emitting resource and making energy efficiency eligible for allocation of allowance value under cap and trade should be effective and administratively easy to accomplish. This approach is already observed in the northeast Regional Greenhouse Gas Initiative cap and trade program. We expect a production incentive for energy efficiency would complement favorably the production incentive for generation that we described in our modeling.

It is noteworthy to consider an extreme example. If there were only one type of technology and an emissions cap was introduced that reduced emissions, if this cap was binding, the only way it could be achieved would be through a proportional reduction in generation from these facilities. This might result in expanded investment in non-emitting resources in the region or it might result in increased import of power from neighboring states. In the latter case one could expect the leakage in generation would lead to an increase in emissions if fossil units were used to provide that increment in generation.

If output based allocation were used in a state that had a single type of generation technology and the allocation was applied only to that technology but not to non-emitting resources, the consequence would be to drive up allowance prices with no change in the generation mix. The emissions cap would determine the amount of generation coming from the homogeneous generation resources.[16] However, one of the ways that output based allocation can be effective is by directing the production subsidy to the promotion of greater use of and investment in low or non-emitting resources within the regulated region.[17] The difference between the demand for electricity services and generation from the emitting technology could come from non-emitting sources and energy conservation.

A useful modification to output based allocation might be to strategically limit the resources that are deemed eligible. If generation from fossil resources is largely determined by the emissions cap, then there is no need to give a production incentive to those resources. The more important focus could be on the incentive provided to maintain generation in the state (or capped region) coming from lower emitting resources, or non-emitting resources. Limiting the production subsidy that is provided by limiting the qualifying technologies would preserve some emissions allowance value for other purposes.

[15] Including existing fossil, all non-hydro renewables, new nuclear, and 5.8 percent existing nuclear

[16] Bushnell, James and Yihsu Chen. 2012. Allocation and leakage in regional cap-and-trade markets for CO_2, *Resource and Energy Economics*, 234:647-668; Rosendahl, K.E. and H. Storrøsten. 2011. Emissions trading with updated allocation: Effects on entry/exit and distribution. *Environmental and Resource Economics*, 49:243-261.

[17] Burtraw, Dallas, Karen Palmer, and Danny Kahn. 2005. Allocation of CO_2 Emissions Allowances in the Regional Greenhouse Gas Cap-and-Trade Program. RFF Discussion Paper 05-25. Washington DC: Resources for the Future. http://www.rff.org/Publications/Pages/PublicationDetails.aspx?PublicationID=21866

Comments on Allowance Trading between States with Mass- and Rate-Based Policies

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The proposed Clean Power Plan calculates rate-based carbon emissions targets for each state, denoted in pounds of carbon dioxide per megawatt-hour. In writing a plan to demonstrate their state's equivalence to these targets, regulators face at least two fundamental questions if they decide to employ the use of tradable emissions rights markets within their state. The first choice is whether to use a rate-based program, which fixes a carbon intensity standard (potentially equal to the rate-based target set out in the proposed Clean Power Plan) or a mass-based program—which fixes total emissions by allocating a limited number of allowances. The second choice is whether to enable allowance trading between the regulator's state and other states; that is, whether to allow interstate linkage of allowances. Although these two options give states more flexibility in complying with the Clean Power Plan, at least one combination of these options may prove problematic: enabling linkage between a state with a rate-based program and a state with a mass-based program. In this scenario, research suggests that overall carbon emissions are likely to increase relative to a scenario without linkage. This potential outcome seems at odds with the overall objective of the proposed Clean Power Plan and therefore deserves careful consideration.

In an academic article in the journal *Climate Policy*, Fischer[18] clearly describes the conditions under which the linkage between a mass and rate based program might increase overall carbon emissions. Fischer considers a partial equilibrium model of two sectors, each with a representative firm. Sector A choose a mass-based program and sector B chooses a rate-based program, where a firm that produces with a carbon intensity below a given standard creates tradable permits and a firm that produces with a carbon intensity above a certain standard must retire tradable permits. The author makes two key assumptions: that both sectors act as price takers in allowance and product markets, and that the cross-price elasticity of the two products equals zero—effectively meaning that the product markets between the two sectors operate independently. Under these conditions, the author finds that "…allowing unfettered trade between rate-based and [mass-based] programs always raises combined emissions—regardless of the direction of trade…" (Fischer 2003, p S91).

The anticipated rise in overall emissions originates from the nature of linkage and the design of rate-based programs. Linkage between the programs creates gains from trade for both programs, as inefficiencies between the two markets dissipate and those market's allowance prices align. In a mass-based program, these gains from trade do not affect emissions because allowance levels remain static, by definition. In a rate-based program, however, Fischer (2003) argues that gains from trade always act to depress product prices which, in turn, ends up increasing production. This increase in production leads to additional emissions and, consequently, a higher number of allowances are issued—given that rate-based programs issue a variable supply of allowances depending on firm's performance.

In electricity markets, these problems are compounded when differently regulated states also trade electricity on the grid.[19] Even without allowance trade, electricity trade allows production to shift toward generation sources in states that effectively subsidize production with a rate-based allocation. With less generation and more imports in the capped state, local emissions would fall below the cap if the allowance price remained the same. As a consequence, the allowance price falls in the capped sector,

[18] Fischer, Carolyn. 2003. Combining Rate-Based and Cap-and-Trade Emissions Policies. *Climate Policy* 3S2: S89-S103.
[19] See also work by Meredith Fowlie, e.g., https://energyathaas.wordpress.com/2014/11/10/cross-state-power-flows-complicate-the-clean-power-plan/.

causing it to shift away from clean toward more dirty generation. Total emissions remain the same in the capped state, but production is smaller and dirtier. Meanwhile, expanded production in the rate-based state necessarily means total allocations and therefore emissions rise. Allowing additional flexibility mechanisms of allowance trade further exacerbate this shift in production and expansion of emissions.[20]

Insofar as states propose to link mass and rate based programs, there are some measures available for ensuring that overall emissions do not increase due to linkage (several of which are outlined in Fischer 2003).

1. Require states with rate-based programs to convert to mass-based standards prior to trading.
    - This option encourages states to move toward more efficient emissions trading policies and addresses the emissions pressures created both by electricity and allowance trade. On the other hand, it may discourage some states from engaging in allowance trade, which avoids some unwarranted trade but also foregoes some legitimate gains from trade.

2. Require states to tighten their standards prior to allowance trade.
    - This option addresses the overall goal of keeping emissions reductions real, but does not address the incentives to shift production toward rate-based states. This effect remains whether the absolute cap or the performance standards are tightened. The requirement may also deter some states from engaging in trade.

3. Encourage states with mass-based programs to allocate allowances based on performance benchmarks (output-based allocation).
    - This option has the potential to address the problems of production shifting both due to electricity and allowance trade. However, in the long run it pushes the entire system toward allowance allocation mechanisms that distort electricity prices downward, suppress incentives for conservation and energy efficiency, and still create state-specific electricity subsidies (to the extent that performance benchmarks differ). Furthermore, this option asks states with existing mass-based programs to forego valuable auction revenue that has been used to fund critical public expenditures and energy efficiency programs.

4. Encourage states with mass-based standards to implement border adjustments.
    - This option would counter the competitive advantage of rate-based states by imposing a charge on imported electricity equal to the allowance price times the performance benchmark awarded in the exporting state. It has the advantage of dealing with carbon leakage, both associated with electricity and allowance trade, while retaining the ability of mass-based states to use emissions auction revenues for their preferred purposes. There is some precedent for this action in California's emissions trading program, which includes border adjustments, but with some design differences. Some of the complications are similar, including the determination of the state of origin, when electricity is imported from states with different emissions benchmarks.

5. Apply an exchange rate to trades between mass-based and rate-based states
    - This option differs from border adjustment since it imposes a kind of tax on allowance trade, rather than electricity trade. The exchange rate essentially discourages trade unless it is justified by significant abatement cost differences. It is less strict than a ban on cross-regime trading, but introduces its own distortions. Recent research on exchange rates

[20] Fischer, Carolyn. Forthcoming. Trade Between Mass- and Rate-Based Regulatory Regimes: Why Electricity Trade is Bad for Emissions, and Flexibility Mechanisms Are Worse. Washington, DC: Resources for the Future.

shows that they can also have uncertain impact on emissions, depending on the direction of trade flows.[21]

A combination of options 1) and 4) would promote, over time, a transition toward mass-based trading nationwide, arguably the most cost-effective solution. Border adjustments would discourage leakage in the short run and further encourage states to adopt mass-based standards to access the gains available through allowance trade.

In conclusion, we recommend that the Environmental Protection Agency carefully consider the options outlined here to help eliminate or limit the expansion of emissions that results from linkage between mass and rate based programs. The EPA may choose to detail prerequisites or simply to provide guidance to states, in order to encourage best practices.

Further analysis is needed in two areas: 1) the legal feasibility of different measures to counter leakage, and 2) quantitative analysis of the economic and emissions tradeoffs. The economic theory is quite clear that unfettered trade between states that use such disparate approaches to allowance markets will likely increase overall emissions, but additional research is required to understand the magnitude of those effects. In any case, increasing emissions seems at odds with the overall goals of the Clean Power Plan, and cost-effective solutions should be found.

[21] Burtraw, Dallas, Karen Palmer, Clayton Munnings, Paige Weber and Matt Woerman. 2013. Linking by Degrees: Incremental Alignment of Cap-and-Trade Markets. RFF Discussion Paper 13-04. Washington, DC: Resources for the Future.

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Could an alternative compliance payment help states comply with EPA's Clean Power Plan and, if so, how might it be designed and implemented?

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This comment appeared originally as part of RFF's Expert Forum on EPA's Clean Power Plan on November 21, 2014. All responses in the forum are attached in their entirety in Appendix A.

EPA's Clean Power Plan offers substantial flexibility to states and energy providers to achieve environmental goals; however, this flexibility may not be adequate to address the special situations and concerns of every entity. EPA should therefore consider defining an alternative process involving a compliance payment with revenues targeted to specific uses.

Special circumstances may severely raise costs or even pose obstacles to compliance. For example, some states face a front-loaded compliance obligation that implies exceptional rates of emissions reductions by the year 2020. As another example, some plants have recently constructed post-combustion pollution controls that have remaining un-depreciated accounting and economic lives of a decade or more; rapid reduction in the utilization of these plants could impose arguably unfair economic costs. A third example is that many small systems lack a diversity of fuels and technologies, making compliance difficult.

The proposed Clean Power Plan would address these challenges by enabling flexible compliance through emissions rate averaging or emissions trading over multiple units and potentially across states, which can reduce overall costs. However, compliance could involve the purchase of credits from parties outside one's system or state, effectively stripping the state of financial capital that could be used instead to achieve a long-run system transformation. Some entities or states may welcome alternative ways to comply.

EPA should consider broadening the policy goal to more explicitly allow for a fee-based approach. There are multiple ways that revenue might be used, and the level of the fee might be adjusted accordingly. Revenues returned to ratepayers as part of the electricity tariff would lower electricity prices. If the fee took the form of a tax with revenues directed to the state government, electricity prices would rise, yielding a reduction in electricity consumption, and perhaps enabling a lower fee. If the revenues were used for immediate investment in energy efficiency or other technology, or held in an escrow account to accumulate capital for a future investment, then ratepayers would see electricity prices rise and in addition they would begin paying immediately for the investments that would ultimately occur. Consequently, the payment might be lowest in this last case. In each case, however, compliance with the goals of the Clean Power Plan should be built into the plan for using an alternative compliance payment.

Because other comments have addressed a role for an emissions fee with revenues going to customers (see Kathleen Barrón's response to this question in Appendix A) and government, we will elaborate on the alternative with revenues directed to investment.

Revenues dedicated to energy efficiency can be spent promptly and would be expected to yield near-term results, but investments in a technological transformation to low- and non-emitting sources might require years to accumulate sufficient capital and complete projects. States offering a capital investment plan might be given additional intertemporal flexibility, with an accompanying obligation to achieve equal or greater cumulative emissions reductions. In sum, the investment approach does the following:

- Avoids having to meet standards precisely in the near term;
- Introduces a payment set by EPA for excess emissions (or emissions rates) above the standard;
- May direct revenue from the payments to accumulate in an escrow fund;
- Provides an incentive for compliance entities to expedite investments to reduce emissions, avoid the payment, and lower ratepayer costs; and
- Can be designed to accelerate investment in innovative technologies, improve environmental outcomes, and lower costs to producers and consumers.

In effect, the payment is an environmental bond. It would be denominated in dollars per unit of emissions for emissions in excess of a state's target, and it seems important that EPA would identify the payment amount. The amount could be based on system modeling and investment planning to identify the fee that would yield the requisite long-run environmental outcome. As an alternative to a planning process, EPA might allow states to impose a fee calibrated to the estimated social cost of carbon dioxide emissions as identified by the Interagency Working Group. Alternatively, EPA may allow states to impose a fee equal to the marginal cost of compliance expected to emerge in regional trading or averaging programs that others are joining for compliance. The distinction is the revenues collected would remain within the state.

Scholarly research suggests that an alternative payment mechanism linked to investment can be designed to meet and exceed environmental goals and produce more rapid investment in innovative technologies, and improve environmental outcomes at a lower cost than would an inflexible technology mandate (see Patino Echeverri et al. 2012[22], also published in the *Journal of Regulatory Economics*). And reasoning suggests the approach could yield similar investment outcomes in the context of the Clean Power Plan. The basic approach of an alternative payment mechanism is simple. The transparency of this approach may be an appealing attribute to some parties who otherwise view the challenges of the Clean Power Plan as complicated and confusing. The state's obligation in developing its plan would be to describe how the revenues would be used. Such an alternative payment mechanism would provide assurance to ratepayers that their resources remain available within their own system or state.

[22] Patino Echeverri, Dalia, Dallas Burtraw, and Karen L. Palmer. 2012. Flexible Mandates for Investment in New Technology. RFF Discussion Paper 12-14. Washington, DC: Resources for the Future. http://www.rff.org/Publications/Pages/PublicationDetails.aspx?PublicationID=21833

APPENDIX A

RFF's Expert Forum on EPA's Clean Power Plan

www.rff.org/CPPforum

EPA is seeking input on a number of unresolved issues in the proposal through its formal comment process. Many of these topics are complex and multifaceted, requiring informed feedback from numerous stakeholders. To shed light on some of these issues, RFF has posed a series of questions and asked a diverse group of experts to share their contrasting and constructive views so that those providing feedback to EPA can use this information as a resource.

Question Topics

1. What is the definition of the "best system of emission reduction"?

The proposed Clean Power Plan originates from the US Environmental Protection Agency's (EPA) authority under Section 111(d) of the Clean Air Act to require states to submit plans that establish and implement a standard of performance achievable through "application of the best system of emission reduction." EPA chose to interpret the word "system" to encompass: (1) emissions rate reductions at coal plants, (2) shifting generation from coal to natural gas, (3) increasing generation from renewables, and (4) improving end use energy efficiency. A central issue in the environmental effectiveness and legal defensibility of the Clean Power Plan is whether this definition of "system" is within EPA's statutory authority. EPA views the system as the network infrastructure that delivers electricity services to consumers, but others might hold that a system includes only technical operation of emitting plants. What guidance can experts give to EPA on this issue?

Posted September 5, 2014.

Question 1: Response by Nathan Richardson
Associate Professor, University of South Carolina School of Law
Visiting Fellow, Resources for the Future

EPA has sought input on its proposed approach to identifying the best system of reduction. There's a common but important misunderstanding about "best system." The language appears in the section of the act that defines performance standards, which are the tools the agency aims to use to regulate power sector emissions. Many people take this placement to mean that such standards let EPA and the states determine what the "best system" is and then direct emitters to apply that system. But that's not right. The statute says that standards "reflect" the best system, not that they *are* the best system. In other words, regulators get to make their best guess at what emitters could do to cut their emissions (considering costs and other factors), but they don't get to tell them what to do in practice. This is what makes performance standards different from command-and-control regulation. The standards are goals—real and legally enforceable ones—but not mandates about what about what actions emitters will take to achieve the goals.

A corollary of this is that "best system," in my view, not only doesn't give regulators any authority to require emitters to take specific actions, it doesn't even really give them any guidance as to what kinds of emissions-cutting actions they can assume emitters will take (and, therefore, what the components of the "best system" actually are). For example, can regulators consider whether emitters can trade amongst themselves or whether they can work with customers to reduce demand—each of which might reduce the costs of emissions cuts? Despite the broad appeal of the words "best system", I don't think they answer that question. Guidance has to come from elsewhere—other parts of the statute that have actual, substantive weight to them. Unfortunately, Section 111 has nothing like that. I believe this is due to the technology-driven roots of the section; it was long assumed (and for a time explicitly stated) that standards would reflect the best *technology* available to emitters. Some argue that this interpretation should still hold and that, therefore, only demonstrated technological upgrades at the plant should be considered in setting the standard. I think that view is too narrow for a variety of reasons.

EPA's view is to take guidance from the rest of Section 111, which says that states (under EPA guidance) must set performance standards "for" specified categories of sources. EPA interprets standards "for" sources to mean standards that assume (though, again, do not require) sources to take any action that would reduce their emissions. Under EPA's interpretation, all four of its building blocks can be considered in setting standards since each reduces emissions from fossil power plants. Other measures that would help cut atmospheric carbon but would *not* cut fossil power emissions, like paying other sectors to reduce their emissions, or paying to plant trees, are out of bounds. I think that's important, because it means that EPA's broad interpretation isn't unlimited. Given the lack of guidance in the statute and deference shown to the agency's interpretation of statutory ambiguity, I think EPA is likely to survive challenge, with two caveats.

One caveat is that EPA's proposal undermines its own interpretation by grouping coal and gas plants into separate categories. Its second building block explicitly assumes generation will shift from coal to gas. Doing so does cut overall emissions from fossil power, but not those from gas—gas emissions go up. The other four building blocks may have similar effects, especially to the extent that states allow trading. In other words, standards ostensibly "for" the gas category actually *increase* gas emissions. EPA can solve this problem simply by combining all fossil power into one legal category, as it already assumes for purposes of setting targets in the proposal. The agency has cryptically "co-proposed" such a merger of categories, but the traditional split categories remain the primary approach, for reasons that are unclear. The agency has extremely broad powers to define and redefine categories of sources. The fix here is easy—joining all fossil power in the same category—but the agency actually needs to do it or risk unnecessary legal vulnerability.

The other caveat is the view expressed by some judges, including those on the Supreme Court, that they will be less deferential to agency interpretations when those interpretations are based on sparse statutory text and assume broad powers for the agency. Think of this as the *UARG* exception to *Chevron* deference, which I elaborate on in a blog post.[23] This is a risk for the agency, but it may be overblown. Opponents of broad EPA powers would surely prefer to have better arguments than a claimed special exception to *Chevron*.

On balance, I think EPA's view on the "best system of emission reduction" and its four building blocks should survive.

[23] Richardson, Nathan. 2014. Quick Thoughts on UARG v. EPA. June 23. http://common-resources.org/2014/quick-thoughts-on-uarg-v-epa/

Question 1: Response by Jeffrey Holmstead
Partner, Bracewell & Giuliani

EPA's proposal stretches the term "standard of performance" far beyond the breaking point. Under the Clean Air Act, a "standard of performance" is a requirement (usually an allowable emission rate) that applies to an individual facility and is based on the "best system of emission reduction" that will ensure a "continuous emission reduction" from that type of facility. This is clear from the language of the act and almost 40 years of regulatory history. Even now, EPA agrees with this reading of the statute when it comes to new power plants. But when it comes to existing power plants, this term is somehow transformed into a requirement that applies to the state as a whole—a statewide allowable emission rate that varies dramatically from state to state based on EPA's view of how the entire "electricity system" in each state, including both supply and demand, should be changed over the next 15 years. It is highly unlikely that EPA's rather breathtaking new interpretation of a 40-year-old statutory provision will stand up in court.

Section 111 has been in place since 1977 and is quite straightforward. Before issuing any regulation under Section 111, EPA must first identify specific types of facilities (known as "sources") that will be regulated. Then, under Section 111(b), EPA establishes a "standard of performance" that applies to any new source of that type. Over the last 37 years, EPA has set dozens of these standards for different pollutants from many types of sources. In every case, the standard of performance is a requirement (usually an allowable emissions rate) that each "new source" must meet.

Section 111(d) provides that, under certain circumstances, EPA may require states to set a "standard of performance" for "any existing source … to which a section 111(b) standard of performance would apply if such existing source were a new source." It also states, however, that EPA "shall permit the State in applying a standard of performance to any particular source ... to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." Thus, EPA sets a standard of performance for any "new source" in the country, and individual states set a standard of performance for "any existing source" within their boundaries.

The statute certainly contemplates that a standard of performance must be met by each and every regulated source—new or existing. EPA agrees with this reading when it comes to new sources—even for carbon emissions from new power plants. But when it comes to carbon emissions from existing power plants, EPA claims that a "standard of performance" is something altogether different. Thus, instead of requiring states to establish a standard that applies to individual power plants, EPA is now proposing to require each state to meet a statewide emissions rate that is based on, among other things, (1) emissions that, in EPA's view, can be "avoided" by programs designed to reduce the demand for electricity; (2) the amount of business that should be shifted from coal-fired plants to gas-fired plants; and (3) requirements that each state should adopt to compel the construction and use of wind and solar plants. This legally binding standard varies substantially from state to state depending on EPA's view of how each state should change its current electricity system.

EPA justifies this approach based on a statutory provision that defines 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 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."

EPA focuses on the word "system," which is certainly a broad term. And the statute does define a standard of performance, in part, as "the degree of emission limitation achievable through the application of the best system of emissions reduction." The statute also provides that this system must ensure a "continuous emission reduction" from a source being regulated. But the key legal question in this case is *not* what a "system" may be. The statute says that a standard of performance must be based on "*the application* of the best system of emission reduction." In this case, the question is "the application of the system to *what*?" EPA says, "to anything that produces or uses electricity." But the answer, according to the statute and almost 40 years of regulatory history, is "the type of facility being regulated." In the context of Section 111(d), this means to "any existing source," as long as it ensures a "continuous emission reduction" from that source and that, "in applying a standard of performance to any particular source," the state is able to "take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."

For further information, read my July 30 testimony to the US House Committee on Science, Space and Technology.[24]

Question 1: Response by David Doniger, Policy Director, Climate & Clean Air Program and Benjamin Longstreth, Senior Attorney; Natural Resources Defense Council

EPA has a solid legal basis for using a system-based approach when it promulgates the emissions guideline that will govern carbon pollution standards for existing power plants. Under the Clean Air Act, EPA must determine the emissions limit that reflects the emissions reductions achievable using the "best system of emission reduction." 42 USC Section 7411(a)(1). Fossil fuel power plants are part of an interconnected electricity system that matches supply and demand. As many states and utilities have demonstrated, carbon pollution can be reduced by increasing the efficiency of fossil fuel power plants, meeting demand with other lower-emitting sources, and reducing demand through energy efficiency. The "best system of emission reduction" properly takes advantage of all three techniques. Indeed, this is not the first time EPA has looked "beyond the fenceline" under Section 111(d). EPA's 1995 standard for existing municipal waste combustors[25] adopted such a system by allowing nitrogen oxide emissions credit trading between individual combustors. And in 2005, EPA adopted a cap-and-trade system for power plants' mercury emissions under Section 111(d).[26] (That approach failed because power plant emissions of mercury, a hazardous air pollutant, are properly subject to control under Section 112.)

The language of Section 111 supports a system-based approach for at least three reasons. First, the phrase "best system of emission reduction" plainly points toward a broad approach to cutting emissions. According to the American Heritage College Dictionary, a "system" is a "group of interacting, interrelated, or interdependent elements forming a complex whole." A "system" of emissions reduction for the power sector can certainly encompass all the techniques available at reasonable cost for reducing carbon pollution at power plants, not just end-of-pipe controls.

Second, in 1990, Congress removed terms that might have limited the range of options available to EPA. Under the 1977 amendments, standards for new sources were required to reflect "*technological* systems of emission reduction" and standards for existing sources were required to reflect the "best system of *continuous* emission reduction." In 1990, Congress amended this language to remove both the "technological" and "continuous" requirements, returning to language originally adopted in 1970. The effect of these amendments was to expand the range of compliance options EPA may consider in determining the "best system of emission reduction."

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[24] Jeffrey R. Holmstead. 2014. Testimony before the US House Committee on Science, Space, and Technology. July 30. http://docs.house.gov/meetings/SY/SY00/20140730/102574/HHRG-113-SY00-Wstate-HolmsteadJ-20140730.pdf

[25] 60 FR 65415, Dec. 19, 1995, as amended at 62 FR 45119, 45125, Aug. 25, 1997. http://www.gpo.gov/fdsys/granule/CFR-1998-title40-vol6/CFR-1998-title40-vol6-sec60-33b

[26] 70 FR 28606. https://federalregister.gov/a/05-8447.

Third, additional support for a system-based approach is found in Section 111(d)'s reference to adoption of a "procedure similar to that provided by section [110]" of the Clean Air Act. 42 USC Section 7411(d). Section 110 allows for use of system-based measures including "economic incentives such as fees, marketable permits, and auctions of emissions rights." 42 USC Section 7410(a)(2)(A). Through this reference to section 110, Congress indicated that these system-based measures may also be used under Section 111(d). Accordingly, EPA may include them when it establishes power plant carbon emissions guidelines.

Given the integrated nature of the power system, it is arguable that EPA's determination of the "best" system of emissions reductions *must* include the full suite of demonstrated and available measures to reduce emissions at fossil-fuel power plants. Greater reliance on lower and non-emitting energy sources and reduction of demand through energy efficiency programs are well-demonstrated methods of reducing emissions at fossil fuel fired power plants. It is reasonable for EPA to rely on a well-grounded forecast of the supply of additional renewables and energy efficiency, just as in other cases where EPA has relied on well-grounded forecasts of the supply of low-sulfur coal or end-of-pipe pollution control equipment. Accordingly, it is not merely *permissible* for EPA to rely on such system-wide pollution reduction methods. Rather, a rule that ignored these available reduction methods could not be defended as the "*best* system of emission reduction."

For more, see papers by Nordhaus and Gutherz, [27] Konschnik and Peskoe,[28] Ceronsky and Carbonell,[29] and Doniger.[30]

2. **Who should translate the states' assigned rate-based goals into mass-based goals—the states or EPA—and how?**
   EPA's Clean Power Plan assigns each state an emissions rate goal, in pounds of carbon dioxide (CO_2) per megawatt hour (MWh), but also gives states an option to translate this goal into a mass-based goal, in pounds of CO_2. Ten states already have carbon trading programs with mass-based caps, and advocates of this approach argue it would have advantages. However, the methodology for translation remains a source of confusion. EPA could eliminate this confusion by presumptively translating the goals into mass-based goals or, instead, providing further guidance to states on how to translate their rate-based goals to ensure consistency in methods, assumptions, and outcomes. Who should translate EPA's assigned rate-based goals into mass-based goals, and how?

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[27] Nordhaus, Robert R., and Ilan W. Gutherz. 2014. Regulation of CO2 from Existing Power Plants under §111(d) of the Clean Air Act: Program Design and Statutory Authority. *Environmental Law Reporter* 44: 10366. http://www.eli.org/sites/default/files/docs/article_2014_04_44.10366.pdf.

[28] Konschnik, Kate, and Ari Peskoe. 2014. The Case for End-Use Energy Efficiency Programs in the Section 111(d) Rule for Existing Power Plants. Cambridge, MA: Harvard Law School. http://blogs.law.harvard.edu/environmentallawprogram/files/2013/03/The-Role-of-Energy-Efficiency-in-the-111d-Rule.pdf

[29] Ceronsky, Megan, and Tomás Carbonell. 2014. Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants. Washington, DC: Environmental Defense Fund. http://www.edf.org/sites/default/files/section-111-d-of-the-clean-air-act_the-legal-foundation-for-strong-flexible-cost-effective-carbon-pollution-standards-for-existing-power-plants.pdf.

[30] Doniger, David D. 2013. 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 13-10-D. Washington, DC: Natural Resources Defense Council. http://www.nrdc.org/air/pollution-standards/files/system-based-pollution-standards-IB.pdf

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Posted September 5, 2014.

Question 2: Response by Anthony Paul
Center Fellow, Center for Climate and Electricity Policy, Resources for the Future

See page 8.

Question 2: Response by Jennifer Macedonia
Senior Advisor, Bipartisan Policy Center

The translation of a rate-based state goal into a mass-based state goal is intended to produce an equivalent value. However, depending on which assumptions and methodology are applied, a variety of outcomes is possible. These potential differences impact the stringency of what is required within each state to implement Section 111(d). If the stringency can vary based on available methodological choices, is there truly an "equivalent" value?

Although conceptually simple—Emission Rate (lbs/MWh) * Generation (MWh) = Mass Emissions (tons)—there are at least three thorny aspects to the translation from rate to mass in practice.

3. Future generation is unknown. Like equating speed and distance when time is undefined, converting an emissions rate to an equivalent mass of emissions for a future year is challenging because the amount of future electricity generation is unknown.
4. Measures that will be enforceable under the state plan are to be excluded from the projection scenario. EPA proposes the use of a projected scenario to convert from rate- to mass-based goals and proposes that any programs that will be enforceable under the state plan should be excluded from the scenario. This sets up a decisionmaking loop, where the goal conversion is dependent on decisions to be made in developing a state plan to implement the goal.
5. The state goal is not an emissions rate. The conversion is further complicated because the state goal is not in the form of a simple emissions rate. In setting up a mechanism to credit what is, in essence, a mass-based quantity (the CO_2 emissions avoided through various actions that offset generation and emissions from affected fossil-fired generators), EPA created a new metric for state goals.[31] This quasi-emissions rate includes adjustments to account for CO_2 avoidance from renewable energy, a portion of nuclear energy, and end-use energy efficiency measures.

The quasi-emissions rate means it is not mathematically correct to simply multiply the rate times generation to get mass emissions, as suggested in the equation above. This adds another twist to an already challenging problem of determining the appropriate generation for converting the rate-based goal to a mass-based goal.

Such uncertainty has the potential to create confusion, lead to delays, and produce inequalities across states. Given the tight timing, the importance of state-specific analysis to develop an implementation plan that meets state objectives, and the time required for potential collaboration with stakeholders, legislatures, and other states, it would be detrimental to find out years into that effort that EPA did not find the translation to a mass-based goal approvable.

States and stakeholders would benefit from upfront clarity regarding an acceptable methodology and assumptions, as well as an opportunity to comment on the proposed conversion in a transparent way and before all of the detailed work is done to analyze, negotiate, and develop a plan. Thus, it would be beneficial for EPA to clarify both (a) the proposed methodology for converting from rate- to mass-based

[31] See discussion here: http://bipartisanpolicy.org/blog/unpacking-epa-proposed-clean-power-plan/.

goals and (b) the result of applying the methodology to calculate mass-based state goals, subject to a public notice and comment period.

Question 2: Response by David Littell
Commissioner, Maine Public Utilities Commission
Former Chairman, Regional Greenhouse Gas Initiative

When EPA released the proposed Clean Power Plan in June, states were assigned emissions rate goals (CO_2 per MWh) for reducing carbon emissions from existing power sources. EPA also provided states with the option to translate these emissions rates into mass emissions targets (CO_2 tons). Moreover, EPA recognized the effectiveness of market-based regional mass emissions programs like the Regional Greenhouse Gas Initiative (RGGI).

Market-based greenhouse gas reduction programs have proven to be one of the best and most cost-effective methods to reduce carbon emissions. The RGGI states have experienced a 40 percent reduction in power sector CO_2 emissions since 2005, due to a combination of factors, including market forces, RGGI and other state clean energy programs, and multi-pollutant control programs. These emissions reductions have been realized even as the regional economy has grown.

Multi-state programs with mass-based compliance more closely align with the regional nature of the electricity grid and foster regional cooperation to deploy the least-cost solution to comply. The RGGI states have witnessed how our regional structure has allowed for efficiencies that would have been otherwise constrained by state borders.

Programs like RGGI enable compliance through market mechanisms that allow market participants to seek out the least expensive emissions reductions across the region. By expanding the geographic scope of compliance, obligated entities are able to take advantage of a portfolio of assets to comply at the lowest costs. Multi-state approaches increase market liquidity and help mitigate risk by spreading risk across more entities and a larger region. All of this supports cost-effective compliance.

A regional program, specifically a mass-based approach, provides for a simple, transparent, and verifiable compliance mechanism. The RGGI states are often asked if managing and accounting for a regional mass budget program is difficult. Our answer is no, as we have developed systems to effectively track emissions, allowance distribution, and compliance at both the state and regional level. Without a mass cap, it is more complex to document and verify emissions reductions attributable to programs that support renewable energy and energy efficiency. With a mass emission budget, emissions are limited by allowances distributed. The emissions reduction benefits of multiple policies are captured by the emissions budget. The regional mass-cap serves as a transparent, simple, and effective compliance tracker.

Although EPA recognizes the benefits of market-based mass emissions programs, there are many questions that it will need to address to support the use of mass emissions targets for 111(d) compliance. While some anticipated that EPA would release a mathematical calculation for translating the rate targets to mass emissions targets, EPA instead released several technical support documents, including one that discusses potential analytic approaches for translating from the rate-based emissions goal to a mass-based goal,[32] and projecting the emissions performance that would be achieved through state plans.

[32] US Environmental Protection Agency (EPA). 2014. Clean Power Plan Proposed Rule: Projecting EGU CO_2 Emission Performance in State Plans. Technical Support Document. Washington, DC: US EPA http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-projecting-egu-CO2-emission-performance.

The modeling described by EPA in the technical support document requires a state to develop assumptions and projections for electricity, load growth, cost and performance of electric generating technologies, and transmission capability and expansion. Electricity system modeling is regularly done but is no small task and states would not only be developing assumptions for their state, but also other states in their region or power pool. While the state-specific burden is lessened for states developing multi-state plans, assumptions still be need to be made for neighboring states to those in the multi-state plan. How much will these assumptions vary in different state modeling and how could these differences impact the mass emissions translation across states? One thinks EPA will want some consistency in modeling approaches, resource and load, and new transmission build assumptions.

The modeling process includes a reference case, alternatively called a baseline case, and a mass-based emissions policy scenario where the mass emissions target is generated by applying the rate-based goals. There is also a state policy plan case. Clarity on which current state policies and plans are included in the reference case versus the state plan case is necessary; I would argue EPA must provide that clarity in a way that does not penalize early movers. If an early mover's energy efficiency, carbon reduction, and renewable energy programs are incorporated into the reference case, it follows that all on-the-books programs are taken as part of the baseline introducing a serious first-mover penalty.

Another area for clarification is the calculation of a regional target from individual state rate targets. If modeling is necessary to determine the emissions targets, do states model the individual state rate targets, or model a regional target to determine the mass emissions? Should the regional target be weighted by each state's contribution to fossil fuel generation (111[d] affected generation) or total generation? Should this be based on past generation (e.g., 2012 generation), or projected future generation (e.g., 2030 generation)?

And what about 111(b) new sources and the translation to mass emissions? Where do they fit into the translation to mass if the EPA state rates targets are for 111(d)-affected sources? Presumably, new sources are excluded unless a state opts to include them, in which case, presumably, the new sources would be counted in the rate and mass calculations for those 111(b) sources a state opts into its 111(d) program.

While these questions need to be addressed, EPA should be commended for developing a rule that raises these issues and recognizes the diversity of state energy policies to achieve real and cost-effective carbon reductions.

Question 2: Response by Tom Lawler
Washington, DC Representative, International Emissions Trading Association (IETA)

Fundamentally, IETA supports market solutions as the best means to drive emission reductions at the lowest cost to the economy. We believe enabling states to convert the proposal's rate-based goal to mass-based goals is a necessity if states are going to be able to harness many of the flexibilities the proposal contemplates. Currently, the most effective programs being implemented by states are the cap-and-trade programs of California and RGGI, as well as the utility planning approaches utilized by Colorado and Minnesota. Having a mass-based goal is an important starting point for other states to be able to contemplate whether these types of approaches would be the best method for complying with the Clean Power Plan.

However, as the proposal's technical support document recognizes, there is not a simple method for making the conversion. A state must undergo a very complex and expensive modeling exercise to determine the mass-based equivalent to the proposal's goals.

Unfortunately, because of the amount of effort and resources a state would have to expend to simply determine whether a mass-based goal would be a workable approach, we are concerned that states will forego that option. Additionally, it is our belief that the lack of mass-based equivalent goals is a major barrier to regional cooperation. Due to the state-specific nature of the proposed goals, it is very difficult for states to discuss a regional approach without having a means to make an "apples to apples" comparison of their states' reduction requirements.

The agency should assist states with translating the plan's rate-based goal to a mass-based goal by providing a presumptive translation for all states or simply providing standardized guidance on the analytical tools and assumptions needed for making the conversion.

Simply put, we believe this information is needed, and we have written EPA requesting that the agency provide presumptive mass-based standards for each state. We believe this information will inform many states' and businesses' comments on the rule, and it should be provided while they have an opportunity to respond during the formal commenting process.

We recognize that developing this conversion requires several specific assumptions to be made as part of the modeling process. This is why the information should be provided while the comment period is still open, and why the goals should be "presumptive." If a state would like to challenge any or all of the assumptions that drive the outcome of the conversion, the state should be able to run their own numbers and justify why the assumptions should be different. The point is to start the conversation for states and regions to utilize all of the cost-saving, flexible options a mass-based standard can offer.

3. Is it possible for existing natural gas power plants to increase average utilization to 70 percent (building block #2) and, if so, at what cost?

EPA's Clean Power Plan includes four building blocks that the agency used to assign each state an emissions rate target. Building block #2 assumes that states can increase the average utilization of existing natural gas power plants to 70 percent, substantially higher than current rates. Do such opportunities exist, and at what cost? Would an increase in the utilization of existing gas facilities render them unavailable to balance the intermittent supply from renewable energy generation?

Posted September 17, 2014.

Question 3: Response by Dallas Burtraw
Darius Gaskins Senior Fellow, Resources for the Future

See page 6.

Question 3: Response by Robert Hilton
Vice President, Power Technologies for Government Affairs, Alstom Power Inc.

If you address this from the technical perspective, there is no question that the natural gas combined cycles (NGCC) that EPA focuses on are fully capable achieving and maintaining a 70 percent capacity factor. The gas turbines were designed for this level of operation, as base loaded, and the heat recovery steam generators would operate much better with less maintenance if operated as base loaded rather than cycling. There is ample support and service available to bring less efficient machines into competitive operation and to maintain the existing fleet at best operating condition.

However, the real issue lies in different sectors of the market. As noted by EPA, NGCCs currently average approximately 46 percent capacity factor in the most recently available data. The primary reasons for this level of operation are as follows:

1. Economic or merit order dispatch: Even with today's historically moderate to low natural gas pricing, not all NGCCs can compete in all markets based on bidding into competitive markets. EPA proposes that states will fix this situation by forcibly adjusting dispatch order.
2. Over-capacity in certain regions of the Federal Energy Regulatory Commission, particularly regulated states: In many regions, there still exists excess capacity, largely owing to the fact that electricity demand has not fully recovered to pre-recession levels. With much of the NGCC capacity comprised of independent power producers or merchant plants, we see preferential dispatch for the regulated resources, thus leaving merchant plants as peak suppliers.
3. Available fuel resources: Distribution infrastructure for natural gas still remains problematic in certain regions, so supplying NGCCs with adequate gas year round will cause some NGCCs to run on liquid fuels or shut down, reducing capacity factors.
4. Consideration of plant locations and grid requirements for geographical area power demand: A few units may be located in areas where the demand is insufficient to reach these proposed capacity factors.

Coal plants have traditionally provided the base load with capacity factors of 65 to 73 percent, but presumably in EPA's scenario this will be significantly reduced. Nuclear will remain in the 90 percent level for those units that are maintained in the fleet. For natural gas to assume the base load required to meet EPA's scenario, the four issues will need to be addressed with careful modeling and planning. Assuming states follow EPA's suggestion of tilting the market to an environmental dispatch, it would seem likely this will cause some increase in the price of electricity.

Finally, this further raises the issue of providing backup for renewable power intermittency. It would seem most likely this will be covered by simple cycle units that can quickly enter the market and, unless they exceed 219,000 megawatt hours of operation, will remain exempt from regulation. This may put further strain on the natural gas delivery system. Otherwise, it will be logical that backup power will come from a portion of the existing coal fleet that has been reduced in capacity factor in favor of NGCCs. However, with careful modeling and planning, even at a 70 percent capacity factor, there can be adequate head room for NGCCs to still provide significant backup to renewables, depending on demand.

Question 3: Response by Steve Corneli
Senior Vice President, Policy and Strategy, NRG Energy

The most noteworthy aspect of EPA's building block #2 may well be not what it is, but when it is applied. It is clear from the arithmetic in EPA's technical support documents that EPA assumes full redispatch to the maximum assumed level in 2020 and each year thereafter, and that the proposed rule's interim goals are in fact derived by averaging together the annual targets based on this assumption (see Appendix 1 of EPA's goal computation technical support document[33]). This, together with the proposed rule's requirement that the interim goal be met on average in the first 10 years, would require most of the redispatch-related emissions reductions to be achieved in 2020.

Such "overnight." large scale redispatch raises a number of daunting problems in the real world, which are inadequately addressed in EPA's analyses. In states with a large number of existing combined cycle units and existing coal plants, such a sudden major redispatch has the potential to create resource

[33] US Environmental Protection Agency (EPA). 2014. Goal Computation Technical Support Document. Docket ID No. EPA-HQ-OAR-2013-0602. Washington, DC: US EPA Office of Air and Radiation. http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-goal-computation.pdf.

adequacy challenges by stranding assets needed for reliability, increasing consumer costs, and, in all likelihood, leading to unnecessarily large amounts of new natural gas power plant investment and the long term lock-in of their CO_2 emissions.

Consider, for example, a hypothetical state that has approximately one-third of its power supply from coal plants and one-half of its power supply from combined cycle plants. Under typical recent capacity factors for combined cycle gas (44 percent) and coal plants (65 percent), building block #2 reductions would require coal plants in the state, on average, to reduce their generation output by 60 percent. Adding in the other building blocks will require additional generation reductions from coal plants, in some cases to 80 percent or more. Reducing coal plant generation output from existing plants by such large amounts overnight raises two immediate problems:

1. The potential to render many baseload plants—which are only economic to operate at relatively high levels of output—unable to recover their fixed operations and maintenance costs, leading to immediate economic mothballing or retirement.
2. 2. State policies that inadvertently drive even more plants into economic retirement. For example, a uniform carbon price that would be sufficient to achieve the redispatch of 60 percent or 80 percent of a state's coal plant output would likely severely challenge the economics of all of its coal plants.

Going back to our hypothetical example, the sudden retirement of most or all coal plants in a state where they make up one-third of the supply stack clearly will threaten resource adequacy (unless the state enjoys a 33 percent or greater reserve margin) and risk a major resource adequacy crisis in states with much smaller reserve margins. Such a crisis would almost certainly be met by deployment of new natural gas plants—whose dispatchable capacity counts toward reserve requirements and whose CO_2 emissions simply don't count under the proposed rule.

By contrast, a more gradual phase-in of building block #2 over time would avoid this reliability-driven rush to new gas-fired generation. Such a phase-in should also allow a more thoughtful transition to increasingly competitive renewables and other clean energy resources, less emergency-inspired new gas plants, and lower CO_2 emissions from the power sector as a whole at a lower cost.

4. **Did EPA appropriately construct building block #4 regarding options for states to improve energy efficiency?**

   Expanding utility and state efforts to promote greater efficiency in electricity use (the fourth building block in EPA's proposed Clean Power Plan) will reduce demand on power plants, thereby reducing emissions and saving money for electricity consumers. To set the state-specific goals for emissions rate reductions laid out in EPA's proposal, the agency determined that each state can eventually achieve a 1.5 percent savings in energy consumption per year based on energy efficiency resource standard goals that have been adopted or recently achieved in selected states. Did EPA appropriately construct building block #4?

   Posted September 23, 2014.

Question 4. Response by Steven Nadel
Executive Director, American Council for an Energy-Efficient Economy (ACEEE)

EPA took a major step in explicitly embracing inclusion of energy efficiency in the Clean Power Plan (CPP). The agency determined that each state should be able to gradually ramp-up its energy efficiency programs in order to eventually reduce electricity use by 1.5 percent per year. This level of savings is readily achievable, as six states have already achieved or exceeded this level of savings (Arizona, Hawaii, Massachusetts, Michigan, Rhode Island, and Vermont). Additional states are on-record as planning to ramp-up to this level of savings, including Maine, Maryland, Minnesota, New York, and Washington. (Information on state accomplishments and plans will be detailed in ACEEE's *2014 State Energy Efficiency Scorecard*, to be released in October). These levels of annual savings are also supported by several "bottom up" studies of energy efficiency potential that go beyond today's standard energy efficiency programs and also include new efficiency measures and program approaches.

In our opinion, this building block was constructed in a reasonable way, although we will be suggesting some refinements and improvements in our formal comments to EPA. These refinements and improvements include the following:

1. Explicitly adding efficiency opportunities from updated state building codes and from expanded use of combined heat and power systems to each state's target. ACEEE estimated state-specific savings available from these two measures in an April 2014 report.[34]
2. Increasing the rate by which states ramp-up to the 1.5 percent level, from the 0.2 percent per year proposed by EPA to 0.25 percent per year as achieved recently by such states as Arizona and Michigan.
3. Giving states full credit for the energy savings they achieve. In the current EPA proposal, states that import power (such as Maryland) receive only partial credit. Also, the formula by which energy efficiency savings are credited to emissions rate improvements needs to be refined as the current formula makes some math mistakes and does not give full credit for the efficiency savings; we will be suggesting corrections so efficiency savings are fully credited.
4. Clarifying a number of details on how building block #4 will be implemented; in particular, including good but reasonable procedures for evaluating and documenting energy efficiency savings.
5. Correcting the economic analysis to use recent actual costs of energy efficiency programs plus moderate escalation rates. The current EPA economic analysis is overly conservative as it applies multiple escalation rates, resulting in average costs more than double those reflected today (recent actual costs having averaged 2.8 cents per kWh savings as documented in a March 2014 ACEEE report[35]).

With these refinements, ACEEE estimates that nationwide energy efficiency savings and emissions reductions would about double relative to what EPA estimates in its Clean Power Plan proposal. Furthermore, states will be free to include even more energy efficiency in their compliance plans. ACEEE's April 2014 report estimates that many states can use energy efficiency to achieve all of the emissions reductions called for in the draft Clean Power Plan.

Question 4: Response by Bruce Braine
Vice President, American Electric Power

Building block #4, energy efficiency (EE), plays an important role in EPA's development of state-by-state CO_2 reduction requirements. However, EPA has identified no authority for regulating customer end-uses of electricity. Energy policies that include EE programs and goals are traditional areas of regulation reserved for states under the Tenth Amendment, and included in integrated planning processes in states with vertically integrated utilities. Thus, the use of building block #4 in setting the Section 111(d) proposed standards is not appropriate.

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[34] Hayes, Sara, et al. 2014. Change Is in the Air: How Sates Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution. Research Report E1401. American Council for an Energy-Efficient Economy. http://aceee.org/research-report/e1401

[35] Molina, Maggie. 2014. The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. Research Report U1402. American Council for an Energy-Efficient Economy. http://aceee.org/research-report/u1402

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In addition, EPA has not appropriately constructed building block #4 and has substantially overstated the amount of EE that could be achieved by states in the future in setting the 111(d) CO_2 standards. EPA projected increasing levels of EE based on its evaluation of "best practices" among the states, ultimately developing specific goals that increase each state's EE measures by approximately 1.5 percent of sales of electricity each year. The proposed EE targets are detailed extensively in EPA's Greenhouse Gas Abatement Technical Support Documents.[36] Much of the data and methods were developed by EE advocacy organizations. The metrics adopted by EPA largely incorporate these findings, and differ substantially from the engineering-based analyses that have been conducted on the topic. One study conducted by Lawrence Berkeley National Laboratory reported potential estimates for EE savings from 0.5 percent (low case) to 1.1 percent (high case). Several other individual studies and meta-analyses of EE potential, conducted mostly by EE advocacy organizations or consultants to EPA, as well as EPA's own analysis are nearly all "top-down, policy-based approach" studies. Only one study analyzed by EPA used a "conventional bottom-up engineering approach." This study by the Electric Power Research Institute (EPRI) is contained in a report that was released in 2009 with an update in 2014. Notably, EPRI's estimate for average annual achievable potential based upon its engineering approach was 0.5 percent to 0.6 percent per year. Ultimately, EPA chose to use 1.5 percent as the "best practice level."

Additionally, EPA uses EIA Form 861 data as the baseline level of the amount of EE achievements by utility demand-side management programs. EPA acknowledges the consistency and quality issues with this data resulting from the self-reported sourcing and differing methodologies in estimating these data. EPA does not fundamentally address this issue.

While EPA did use state-specific data from Form 861 for establishing starting points for EE levels, it applies "national" estimates of EE potential to this data and applied an EE growth rate historically only experienced in other best-practice states. The applicability of both these metrics has some fundamental flaws, based on the variability of state-specific factors, such as:

1. *Relative industrial, commercial, and residential consumption*
   Some states have higher manufacturing and industrial consumption than others (such as the Northeast) with higher levels of service-economy industries. States with larger commercial and industrial usage increases the base substantially (greater overall consumption levels due to more energy-intensive loads), which then increases the absolute EE goal levels as well. Also, states that currently allow industrial customers to opt out of utility programs may have to re-visit these determinations and encounter resistance from these customers.
   Implementing utility-sponsored EE at manufacturing and industrial facilities is more challenging and costly. Many such customers have already implemented economically justified EE improvements for cost-competitiveness reasons because they often have better access to capital, at lower rates, and are generally better informed of the options.
2. *Lighting standards*
   Utility-sponsored EE programs have traditionally relied heavily upon lighting programs for the vast majority of their savings (generally, compact fluorescent lamp programs for residential customers and T-8 lighting retrofit programs for commercial customers).
   With adoption of new lighting standards from the Energy Independence and Security Act (EISA), this broad, inexpensive EE resource will largely fade quickly. Statements made regarding EE achieved "historically," due largely to lighting programs, ignore the impact of EISA lighting standards and other code changes that limit future EE potential. In fact, there is no empirical

[36] US Environmental Protection Agency (EPA). 2014. GHG Abatement Measures Technical Support Document. Docket ID No. EPA-HQ-OAR-2013-0602. Washington, DC: US EPA Office of Air and Radiation. http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

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evidence of any future utility-sponsored EE programs achieving levels even approaching those achieved through lighting programs of the past.

3. *Other EE options*
   Other options need to be relied upon to achieve incremental improvements going forward. Utilities will need to mostly default to thermal efficiency measures, such as heating, ventilation and air conditioning (HVAC) upgrades and weatherization measures, which typically have a higher cost to achieve.
4. *Customer economic challenges*
   EE improvements are also expensive for customers, often requiring significant capital investment. This is problematic. Customers usually avoid such large expenditures until a precipitating event occurs (HVAC failure, for example). And with current economic conditions, this is even the more challenging. Longer-term, we anticipate continued difficulty in motivating customers to pay premiums for such EE improvements due to significant portions of our service territory being economically disadvantaged. (For example, households served by our subsidiaries in Texas have household incomes 25 percent below the US national average.)

Question 4: Response by Karen Palmer
Research Director and Senior Fellow, Resources for the Future

The purpose of EPA's building block #4 is to define the electricity generation savings that states could achieve through energy efficiency programs and incorporate those potential savings into the emissions rate target calculation as a non-emitting energy resource, similar to wind or solar power. The higher the energy savings potential, the tighter the state's emissions rate obligation under the Clean Power Plan policy, all else equal.

EPA bases its calculations on existing state policies: 24 states have adopted Energy Efficiency Resource Standards (EERS) that target a specific minimum ratio of energy savings resulting from efficiency programs to total electricity consumption. Twelve of those states have EERS policies that require, or soon will require, a 1.5 percent incremental reduction in total statewide electricity consumption each year—and that is the target that EPA adopts in building block #4. For states that are net importers of electricity, savings targets are adjusted downward by the fraction of electricity consumed that is generated within the state; states that are net power exporters can claim the full amount of energy consumption savings in their target calculation. States that have no or limited experience with EERS policies or efficiency programs more generally are given time to ramp-up to the ultimate 1.5 percent annual energy savings goal.

Setting aside the uncertainty surrounding estimates of energy savings resulting from existing energy efficiency programs (and thus from state EERS policies), the approach that EPA takes raises a couple of questions about the cost-effectiveness of this particular building block. First, states with ambitious existing energy efficiency programs tend to have a larger obligation than states where energy efficiency policies are less advanced. How these differences will impact cost-effectiveness at the national level is an open question. One might expect there to be more low-cost opportunities for saving energy in the inexperienced states where energy-using equipment and buildings are presumably less efficient than in the more experienced states. But it could also be the case that more experience with running energy efficiency programs results in learning by doing—and greater future energy savings at a lower cost. Or both factors could be at play simultaneously with the ultimate answer depending on the balance between the two.

Second, state targets under building block #4 are not differentiated based on the potential for associated carbon reductions. Indeed, states with some of the highest building block #4 requirements, including Maine, California, and Connecticut, have some of the lowest historic CO_2 emissions rates. In contrast, some high emitting states, including Wyoming and West Virginia, have some of the lowest efficiency potentials. (This latter observation is not surprising as high emissions rates tend to be correlated with low electricity prices and thus weak economic incentives to encourage energy savings through investments in efficiency, setting aside environmental arguments for such investments). Across the 50 states there is a small negative correlation between efficiency potential and average CO_2 emissions rates in 2012. This lack of correlation raises the question of whether a more targeted approach would improve both the effectiveness and cost-effectiveness of this building block.

Another important question is how best to measure and verify energy savings, if states choose to incorporate energy efficiency into their state compliance plans. As I discuss in a blog post,[37] current methods of efficiency evaluation, measurement, and verification are often lacking in the rigor necessary to provide a clean and unbiased estimate of energy savings. Going forward, states need to find ways to incorporate more robust evaluation methods into efficiency program designs if these programs are to play a role in their state plans under the Clean Power Plan. Such methods include more use of randomized control trials or quasi-experimental methods, as described in and recommended in the joint State and Local Energy Efficiency Action Network report[38] on evaluation of behavioral energy efficiency programs, issued jointly by EPA and the Department of Energy. All efficiency programs have a behavioral aspect to them that current approaches to evaluation tend not to address very well.

The development of compliance plans for the Clean Power Plan provides an opportunity for states and utilities to gain experience with these more robust evaluation methods. Given the decade-long compliance period that starts in 2020, a full six years from now, there is time for utilities and states to experiment with new evaluation methods. As these experiments unfold, EPA, utilities, and the states can start to build a base of knowledge that will enable better forecasts of future energy savings and energy efficiency potential, better targeting of energy efficiency resources, and, ultimately, more cost-effective policies for saving energy and reducing carbon emissions.

5. **Does EPA make appropriate assumptions regarding the deployment of renewable energy in its proposed Clean Power Plan (building block #3)?**
   One way for states to reduce their carbon emissions is to expand their renewable and low-carbon power generating capacity; this is building block #3 in EPA's proposed Clean Power Plan. EPA assumes that each state can increase its renewable energy generation to achieve a "best practices" scenario—a level it says is "reasonable and consistent" with existing policies that have already been implemented by a majority of states. This assumption directly influences the stringency of each state's carbon emissions target. Does EPA make appropriate assumptions regarding the deployment of renewable energy in its proposed Clean Power Plan?
   Posted October 2, 2014.

Question 5: Response by Megan Ceronsky
Director of Regulatory Policy & Senior Attorney, Climate & Air Program, Environmental Defense Fund

The proposed Clean Power Plan identifies the "best system of emission reduction" to address carbon pollution from power plants as comprised of four building blocks: (1) efficiency improvements at coal-fired power plants; (2) shifts in utilization away from higher-emitting fossil plants towards lower-emitting

[37] Palmer, Karen. 2014. Energy Efficiency in 111(d): Evaluating Energy Savings for Carbon Reduction. June 23. http://common-resources.org/2014/energy-efficiency-in-111d-evaluating-energy-savings-for-carbon-reduction.
[38] State and Local Energy Efficiency Action Network. 2012. Evaluation, Measurement, and Verification (EM&V) of Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations. Prepared by A. Todd, E. Stuart, S. Schiller, and C. Goldman, Lawrence Berkeley National Laboratory. http://behavioranalytics.lbl.gov.

fossil plants; (3) deployment of zero-carbon generation sources such as wind and solar; and (4) harvesting demand-side energy efficiency improvement opportunities. This system best satisfies the statutory command of the Clean Air Act, which directs EPA to identify the system that maximizes emissions reductions, considering cost and impacts on energy and other health and environmental outcomes. This system also reflects what is happening across the country (and indeed, around the world) to reduce carbon pollution—states and companies are using the interconnected electric system as a whole to cut carbon pollution, deploying zero- and low-emitting generation and reducing reliance on high-emitting generation, and doing so flexibly to ensure that reliability is maintained and emissions reductions are achieved cost-effectively. Fifteen states wrote to EPA Administrator Gina McCarthy as the Clean Power Plan was being developed to describe the success they have had in deploying this system, cutting carbon pollution from power plants by 20 percent between 2005 and 2011, with some states achieving reductions of over 40 percent during that period.

Renewable energy is our future. More than 60,000 megawatts of wind energy capacity have been installed in 39 states and an additional 12,000 megawatts are under construction. Wind power capacity in the United States has increased nine times over since 2005, supporting over 80,000 jobs and driving a new manufacturing sector with over 550 facilities across the country. Solar generating capacity is also rising rapidly—increasing by 418 percent between 2010 and 2014. PG&E has connected more than 100,000 customers with solar panels to the grid, saving the average residential customer with solar panels $130 a month. Costs of renewable generation have been falling rapidly, and power companies such as Xcel, DTE, MidAmerican, Georgia Power, and Austin Energy have announced renewable energy purchases that are outcompeting fossil-fueled alternatives and that will lower customer bills by saving fuel costs.

The Clean Power Plan's assessment of the potential for renewable energy to reduce carbon pollution bases state targets on an average of existing renewable energy policies in different regions of the country. By taking this approach—effectively looking backward—the proposal fails to reflect the dynamism in renewable energy deployment that is happening across America, and fails to satisfy Section 111's technology-forcing framework. The proposed alternative approach, which would consider the technical and economic potential to harvest renewable energy in each state, has the potential to better reflect the country's vast renewable energy resources. The analysis underlying the alternative approach needs to be updated to reflect current technologies (such as taller wind turbines and distributed generation) and current costs (which are falling rapidly). An up-to-date analysis of the technical and economic potential for renewable energy to cut carbon pollution will provide a strong legal and technical foundation for the Clean Power Plan, and help facilitate our transition to the clean energy–fueled economy of the future.

Question 5: Response by Jeremy Richardson
Senior Energy Analyst, Union of Concerned Scientists

For establishing the emissions reduction potential from the renewable energy building block, EPA relied on existing state-level renewable electricity standard (RES) policies as a benchmark. They split the country into six regions and established a regional target for renewable energy by averaging the existing state RES requirements within each region. EPA then calculated a growth rate for each region needed to meet that level, and applied the growth rate to each state's renewable generation in 2012.

The resulting level of renewable energy generation that EPA estimates states could feasibly achieve is quite modest: roughly 524 million MWh in 2029, or approximately 12 percent of the total US power mix. That's only marginally more ambitious than what the US Energy Information Administration (EIA) projects for renewable energy generation under its business-as-usual (e.g. no new policies) case: 444 million MWh. Half of the states do not even reach their region's renewable target in EPA's proposed plan. Worse, in 2020, EPA's renewables targets are less than what EIA says will be achieved under business as usual. Seven states exceeded EPA's 2030 targets with existing generation—in 2013.We view EPA's methodology in determining the potential for building block #3 as more of an "average system of emissions reductions" rather than the best system.

We note that there are at least six ways that EPA could strengthen the renewables building block:

- *Factor in renewable energy growth between 2012 and 2017.*
  EPA assumes that states begin increasing renewable energy in 2017, but beginning at 2012 levels. This is an overly conservative method that excludes incremental renewables added in 2013, and projects planned for 2014 to 2016. It's important to capture the tremendous growth of renewables in recent years as costs decline. From 2009 to 2013, wind capacity increased by 75 percent and solar capacity by 473 percent. Average costs of wind power dropped more than 60 percent since 2008; solar photovoltaic systems costs fell by about 40 percent from 2008 to 2012, and another 15 percent in 2013.
- *Incorporate full renewable portfolio standard (RPS) compliance into state targets.*
  EPA's methodology results in 17 states with lower renewable targets than the level that the Lawrence Berkeley National Lab projects they will reach by meeting existing RPS mandates.
- *Remove (or relax) artificial limits on growth rates.*
  EPA assumes that state renewable generation levels off after reaching regional targets.
- *Set growth rates to what leading states are achieving.*
  Instead of basing growth rates on policy mandates, EPA could instead estimate potential by looking at what states are already achieving.
- *Improve cost assumptions for renewable energy in integrated planning model (IPM) frameworks.*
  In the alternative method for determining renewables targets, EPA limited the targets by the economic potential determined by IPM modeling. However, the assumed cost assumptions for renewable technologies are higher than recent real-world experience.
- *Include distributed solar, offshore wind, and low-carbon biomass in setting state targets.*
  In its technical and economic alternative approach for determining renewables targets, EPA did not include several technologies that are either already growing rapidly (distributed solar) or are of particular interest to certain regions (such as offshore wind for the East Coast and biomass for the Southeast).

Despite the potential for improvement, the important message here is that EPA's framework provides an opportunity for states to include renewables in their compliance plans. States are free to go beyond the levels of renewables that EPA estimated in order to meet their emissions rate reduction target—and they should, because this is a cost-effective option nationwide.

Question 5: Response by Ray Williams
Director, Long-Term Energy Policy, Energy Procurement Department, Pacific Gas & Electric

Simply stated, the reasonableness of the assumption underlying the renewables building block depends on: 1) the renewables market potential in each region; and 2) the ability of the state and the key participants in each state to realize this potential in a reasonable period of time.

Information needed to address the first issue includes the following:

- The availability of zero-carbon resource potential defined as renewables in a distinct region;
- The portion of zero-carbon resources defined as renewables that are included in setting the goal for each state;
- The portion of zero carbon resources defined as renewables that can be used for compliance (for example, biomass may be an issue); and
- The ability to convert this resource potential to electricity at a reasonable cost.

Information needed to address the second issue includes the following:

- The ability to build any new transmission to bring these qualifying renewables to market—in a timely way and at reasonable cost;
- The need for and ability to integrate this generally intermittent generation into a reliable electric system, particularly as the renewables percentage increases;
- The speed with which the state, the state's suppliers (primarily merchants and utilities), and the state's purchasers (primarily utilities) institute a procurement process that meets the requirements of this building block;
- The relative consistency between the definition of qualifying renewables for states that have a renewable portfolio standard and the definition of renewable energy for this building block, and the ability to reconcile the two; and
- The need for enabling state legislation, and to work out whether this building block is enforceable at the federal or state level.

I would suggest that, to the extent that EPA has not researched these kinds of questions in setting the renewable energy building block and determining what can be used for compliance, there may remain an opportunity to improve the construction of this building block.

6. How can coal power plants reduce emissions and be made more efficient—and at what cost (building block #1)?

The emissions rate targets assigned to states are built on four building blocks that EPA says represent best practice in reducing emissions throughout the electricity system. Building block #1 focuses on measures to make coal plants more efficient. EPA seeks comment on its proposed finding that the average heat rate for coal power plants (the heat content of fuel input per unit of electricity output) could be improved by 6 percent on average across the fleet. Do such opportunities exist, and at what cost? Would they lead to emissions reductions?

Posted October 7, 2014.

Question 6: Response by Dallas Burtraw
Darius Gaskins Senior Fellow, Resources for the Future

See page 3.

Question 6: Response by Anthony Licata
Partner, Licata Energy

EPA's proposal for building block #1 of the Clean Power Plant Rule (CPP) is based on improvements in the heat rate at existing coal-fired power plants. EPA concluded that up to a 6 percent heat rate improvement could be obtained at an average cost of $100 per kW. EPA stated that 4 percent of the heat rate improvement, on average, was achievable through no- or low-cost options it refers to as "best practices" and the remaining 2 percent improvement was achievable with some capital expenditure.

EPA projects 88,000 megawatts of installed coal capacity will be removed from service by 2020, largely from smaller, older, and less-efficient plants. Opportunities for the greatest heat rate improvements would come from these same less-efficient plants, a number of which may be able to achieve a 3 to 6 percent heat rate improvement, even with cost being considered. Most of the remaining plants are "flagship" units—larger capacity and supercritical plants—already have upgrades that may limit heat rate improvements to about 1 percent, meaning that other remaining plants may have to achieve upgrades greater than 10 percent, which is not practical.

There are concerns about EPA's analysis. EPA's conclusion that a 4 percent improvement using "best practices" is possible at no or low cost was based upon an analysis of more than 800 units, using what EPA describes as statistical process control methods. For each unit, the gross heat rate in a given hour over an 11-year period was compared against hourly ambient temperature data and hourly average load as a percent of maximum load. EPA calls this latter variable a "capacity factor", although others consider a capacity factor as averaged over a much longer time. The degree to which the heat rate for the unit is consistent or inconsistent over the 11-year period for any given temperature and hourly average load is, according to EPA, a measure of how well or how poorly the facility is being controlled. A well-controlled unit should, EPA argues, have a very consistent heat rate under a given ambient temperature and average hourly load. To the extent that there is scatter in gross heat rate data for any given hourly load or temperature condition over this 11 year period, EPA considers that a sign that more consistent process control can improve heat rate. It appears that EPA meant that plants could be better controlled with neural networks. Many plants already have a neural network control system. An upgrade to a plant without such a system may see a heat rate improvement of 0.75 to 1.5 percent.

However, the statistical approach EPA used did not consider any technical aspects of the facility, or if any characteristics changed over the 11-year period, including a change in operating mode (switching from base load to cycling), whether the facility conducted a retrofit (installing low nitrous oxides burners, selective catalytic reduction installations, scrubbers, new burner or furnace management systems), or if the facility changed coals or any other characteristics of the fuel. EPA also did not compare units against one another or do any sort of subcategorization. Unfortunately, because there are many more factors that impact heat rate that are beyond the operator's control than just ambient temperature and average hourly load, and because EPA did not factor changes to the plant over that 11-year period, EPA's statistical approach likely mistook the effects of these other parameters and changes to the plant as indicators of poor process control.

Moreover, most power plants are already equipped with statistical process control systems that monitor thousands of plant parameters and are designed to optimize operation of the plant. EPA's analysis that only looked at two parameters is much less reliable than the advanced process optimizers that are already installed at the plants.

Finally, there are few technological opportunities to achieve heat rate improvements at low or no cost. Other than tuning combustion systems and patching leaks in ductwork, low or no cost technologies would provide minimal heat rate improvements. All other technologies that would improve heat rate require capital investment. A paper published in July 2013 by members of the American Society of Mechanical Engineers finds that a 500 megawatt wall-fired coal boiler could achieve a 0.34 percent improvement in boiler efficiency by upgrading its fuel delivery system at a cost of nearly $14 million. A major steam turbine upgrade and rebuild can cost $30 million to $40 million. There appears to be significant cost of heat rate improvements that EPA did not consider in its evaluations of no- or low-cost options.

7. **Should EPA credit early action taken by states to reduce carbon emissions? If so, how?**
   A key question when developing any new climate policy is how to treat existing policies that already reduce emissions. In EPA's Clean Power Plan, the agency proposes that actions taken by states since June 2, 2014 could count toward compliance efforts—which are slated to be measured from 2020. However, some feel that EPA is penalizing early adopters by not recognizing actions taken before this date. If EPA counted all actions taken by states before 2020 toward compliance, early adopters would likely be more fully rewarded; but such an approach might also award credit to actions that would have happened regardless of the Clean Power Plan and consequently decrease the emissions reductions achieved under the plan. Should EPA credit early action taken by states? If so, how?
   Posted October 24, 2014.

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Question 7: Response by Frank Prager
Vice President, Policy and Strategy, Xcel Energy

Since 2005, Xcel Energy and the states in which we operate have made clean energy leadership among the highest of our energy priorities. Working in concert with our customers, state policymakers, and the environmental community, our company has transformed its electric system. Xcel Energy is a renewable energy leader and has been the nation's number one utility wind provider for a decade. We have some of the nation's leading customer energy efficiency programs. We have implemented innovative coal plant modernization and retirement initiatives that have dramatically reduced our system emissions.

The clean energy programs developed in Minnesota, Colorado, and the other states we operate in should serve as models for carbon abatement strategies across the nation. In fact, these programs are exactly the kinds of initiatives that the proposed Clean Power Plan is designed to encourage. They have already resulted in dramatic reductions in greenhouse gas emissions within our system. Xcel Energy has already reduced its carbon dioxide emissions by 19 percent from 2005 levels and will achieve a reduction of at least 31 percent by 2020, 10 years earlier than the administration's 2030 target.

Although we are proud that our clean energy leadership has achieved so much while maintaining reasonably priced power, these initiatives have not been free. Our customers are funding billions of dollars of investments to make them a reality.

Unfortunately, the Clean Power Plan virtually ignores these investments. It would provide very little credit to existing state clean energy programs. The proposal would give an easier compliance path to states that resisted clean energy in the past. Even worse, the Clean Power Plan actually punishes states that are clean energy leaders.

For example, building blocks 1 and 4 of the proposed rule discount the fact that the cheapest coal plant and customer efficiency projects and programs have already been completed in leading states. Building block 2 requires greater emissions reductions in states such as Minnesota that, prior to 2012, replaced aging coal plants with natural gas combined cycle units. Block 2 also punishes states that balance their intermittent renewable energy with natural gas plants. Finally, block 3 requires greater emissions reductions in states and regions that have moved forward with renewables under progressive renewable standards. In other words, the proposed rule takes clean energy leadership for granted.

Unquestionably, the proposed Clean Power Plan would establish more aggressive targets in states that committed early to clean energy leadership. This is bad policy on every level:

- It tells states that they are better off fighting EPA rather than leading the way to cleaner energy.
- It tells companies that the value of a proactive clean energy strategy may be swept away by future regulation.
- It tells customers that they will pay twice if they commit early to clean energy leadership.
- It tells the public that the most beneficial emissions reductions—those that have already occurred—are environmentally irrelevant.

Over the last decade, our states committed to clean energy on the promise that leadership would give them a head start under federal climate policy. There is still time to make this promise a reality. We believe that a few simple changes to the Clean Power Plan will credit early emissions reductions without significantly altering the structure or environmental benefits of the rule. Xcel Energy will continue to work with EPA to ensure that the nation's climate policy recognizes the value of clean energy leadership.

Question 7: Response by Megan Ceronsky
Director of Regulatory Policy & Senior Attorney, Climate & Air Program, Environmental Defense Fund

Under the Clean Power Plan, the United States will finally have Clean Air Act standards to address carbon pollution from existing power plants. During the long wait for these standards, a diverse group of states and companies have acted, leading the way in reducing carbon pollution. They have done so by deploying renewable energy, harvesting demand-side energy efficiency, and by shifting utilization away from high-emitting and toward lower-emitting power plants.

State and private sector leadership in addressing pollution is something that should be recognized and supported. Action at the federal level to address climate-destabilizing pollution is lagging perilously far behind the scope and pace of action that scientists tell us is necessary to mitigate harmful climate impacts and reduce the risk of catastrophic climate change. For these reasons, we have long supported the recognition of early action in the context of the Clean Power Plan. Yet the question of how to do so is complex.

Under Section 111(d), EPA identifies the "best system of emission reduction" available to address dangerous air pollution from stationary sources, and sets emissions performance targets achievable using that best system. This framework—like other frameworks under the Clean Air Act—looks at existing pollution problems and how they can be addressed going forward. It does not provide for an assessment of past emissions reductions by those sources (or that state).

Of course, under the Clean Power Plan, states and companies that have already transitioned toward lower-carbon and zero-carbon energy and energy efficiency are closer to the full deployment of the best system of emissions reduction than others—and EPA should consider clarifying that states that go beyond their targets under the Clean Power Plan would receive credit for those actions under future updating of the carbon pollution standards for power plants.

The years between 2012 and 2020 present a distinct quandary. EPA uses 2012 data on power sector infrastructure in assessing the potential for emissions reductions to be secured under the best system during the 2020 to 2029 compliance period. Crediting emissions reductions secured between 2012 and 2020 would encourage states and companies to act earlier, moving emissions reductions forward in time. All else being equal, earlier action to reduce emissions is certainly better than later action. But the potential to reduce carbon pollution during 2012 to 2020 was not taken into account in setting the state targets. As such, giving compliance credit to those actions taken during this time that would have happened regardless of the Clean Power Plan—take, for example, renewable energy deployed under a renewable energy standard in a state strongly committed to clean energy—would create a bank of compliance credits. Those banked credits would be used by that state during the compliance period in the place of other, beyond business-as-usual actions to reduce emissions—and the overall emissions reductions achieved by the Clean Power Plan would be reduced by the same amount.

There are, of course, highly compelling reasons to begin to take action now to reduce carbon pollution. States and companies can take advantage of the five years between the finalization of the standards and the beginning of the compliance period to gradually build out renewable generation and build up energy efficiency programs so that these resources are ready to deliver carbon reductions. The reductions in co-pollutants that will result will help states deliver cleaner air for their citizens and meet other clean air standards. Companies can develop business models built on a foundation of clean energy and efficiency, and investments in cleaner energy and efficiency will create jobs. Improvements in energy efficiency will cut utility bills for homes and businesses, and spending those savings in their communities will stimulate the local economy. These are simply common sense actions, with tremendous co-benefits—and the existence of an initial compliance date for the long-awaited carbon pollution standards does not alter that common sense.

Question 7: Response by G. Vinson Hellwig
Senior Policy Advisor, Michigan Department of Environmental Quality

The proposed Clean Power Plan currently states: "Emission impacts of existing programs, requirements, and measures that occur during a plan performance period may be recognized in meeting or projecting CO_2 [carbon dioxide] emission performance by affected EGUs according to § 60.5740(a)(3) and (4), as long as they meet the following requirements: *Actions taken pursuant to an existing state program, requirement, or measure, such as compliance with a regulatory obligation or initiation of an action related to a program or measure, must occur after June 18, 2014."*

Michigan interprets the proposed rule as not allowing emissions reductions from measures designed to reduce energy waste installed before June 18, 2014 to count toward achievement of the interim and final goals, even though these measures provide pollution reductions in later years. Michigan does not agree with this proposed cutoff date and instead recommends adopting EPA's proposed option of recognizing emissions reductions that existing state requirements, programs, and measures have achieved starting from the end of 2005. Otherwise, states that have proactively invested in measures to prevent pollution would be economically disadvantaged compared to neighboring states that have not made these investments. These measures are typically paid for through the electric service. States that have not made this program choice have touted lower electric rates as an economic incentive tool. For this reason, Michigan is urging EPA to credit the avoided CO_2 emissions resulting from measures installed before 2012 in a state's plan. At a minimum, EPA should allow the pollution reductions from all measures installed after January 1, 2012 to count toward Clean Power Plan compliance.

The agency should also be aware that only counting emissions reductions from 2020 to 2029 creates a perverse incentive for states and utilities to defer implementation of programs that reduce energy waste, and thus prevent pollution of many kinds, until 2017 or later. In Michigan, for example, Public Act 295 of 2008 set requirements for increased renewable energy and for programs that incentivized energy waste reduction—and implementation continued despite the deep economic crisis and rising energy costs in the state during the intervening years. If the federal Clean Power Plan disallows counting of such measures toward the state's goal— or worse, would disallow credit for pollution reductions achieved by such measures until 2017 or later—EPA is actually creating an incentive to repeal Michigan's (and other states') laws that currently reduce all pollutants. Moreover, it is clear that many states do not have mandatory energy efficiency requirements in place, and as drafted, the rule would further discourage their adoption prior to 2020. This will likely result in more CO_2 (as well as increases in other pollutants, including mercury, acid rain precursors, and particulate matter) being emitted into the atmosphere than might occur under a final rule that encouraged early investment in pollution prevention.

EPA states that concerns over the "acceptable" lifetime of various measures led to the decision to propose not crediting earlier reductions. Although it can be argued that some waste reduction measures have a shelf life, these should not be difficult to establish, as "payback" figures are abundant in available information and other parts of the federal government have expertise setting depreciation schedules that assume reasonable lives of a variety of assets. Additionally, the "shelf life" of measures such as added insulation and replacement windows is so long that there should be no concern. In most cases, the emissions reductions will not be "lost," but continue to provide quantifiable pollution reductions for years to come.

Given the facts that (a) energy waste reduction and pollution prevention measures continue to positively impact our air quality now and in the future, (b) investments were made by Michigan and other states with required programs, and (c) the rule as drafted creates a competitive disadvantage for states that have implemented those measures, credit for early action should be provided for in the final EPA regulation.

8. Should EPA allow states to use a carbon tax to comply with the Clean Power Plan and, if so, how could a state demonstrate the associated carbon emissions reductions?

EPA's proposed Clean Power Plan sets carbon emissions targets for each state, denoted in pounds of carbon dioxide per megawatt-hour of electricity, but does not explicitly mention a carbon tax as an option for states to achieve their targets. Some argue that a carbon tax represents a simple and effective way to reduce emissions. A state that wishes to use a carbon tax to comply with the Clean Power Plan would likely have to convince EPA that this approach would allow the state to achieve its emissions target. Should EPA allow states to use a carbon tax to comply with the Clean Power Plan and, if so, how could a state demonstrate the associated carbon emissions reductions?

Posted November 11, 2014.

Question 8: Response by Michael Wara, Associate Professor and Justin M. Roach, Jr. Faculty Scholar, Stanford Law School; and Adele Morris, Fellow and Policy Director for the Climate and Energy Economics Projects, The Brookings Institution

A carbon tax is a simple, effective, and efficient means for reducing greenhouse gas emissions. Despite the proposed Clean Power Plan's flexibility, it does not acknowledge or explicitly allow for the use by states of carbon excise taxes. As we explain in our comments to the agency,[39] we believe EPA should revise its proposal to be consistent with a state carbon tax as a primary means of achieving the emissions guidelines. A carbon tax as a state implementation strategy makes environmental, economic, and administrative sense because it does the following:

- Discourages each fuel's use in exact proportion to its damage to the climate.
- Incentivizes changes at power plants (for example, more efficient boilers and lower-carbon fuels) and greater energy efficiency by consumers.
- Is market-based, flexible, compatible with existing fuel mixes, and accommodates the "remaining useful life" of equipment.
- Encourages abatement in ways EPA and states can't predict; for example, by helping drive a market for new technologies.
- Is easy to implement: some states already have excise taxes on fuels, and they already monitor greenhouse emissions from regulated sources.
- Gives states the choice of how to use new revenue—they could use it to lower inefficient taxes, potentially providing pro-growth state tax reform along with environmental benefits; or to offset some of a carbon tax's impacts on low-income residents.

Just as for other compliance strategies, a state can demonstrate through economic modeling that its carbon tax program is likely to achieve the emissions standard set by EPA. In fact, compliance using a carbon tax will most likely be easier to demonstrate than for many of the policies EPA suggests in developing its proposed emissions guidelines. And just as for other approaches, if the carbon tax for some reason failed to produce the forecast emissions rates, a state can increase the stringency of its policies, for example, by increasing the tax trajectory.

[39] Wara, Michael, Adele C. Morris, and Marta R. Darby. 2014. How the EPA Should Modify Its Proposed 111(d) Regulations to Allow States to Comply by Taxing Pollution. Climate and Energy Economics Discussion Paper. Washington, DC: The Brookings Institution.
http://www.brookings.edu/~/media/research/files/papers/2014/10/28commentsonepa111dtaxingpollutionmorris.pdf

A carbon tax is a simple approach to using market forces to reduce emissions. In contrast to cap-and-trade, under a tax approach states would not have to allocate allowances, administer auctions, create an allowance registry, monitor trades and positions, or enforce a price floor. A carbon tax can also be implemented by a single state agency, rather than a complex amalgam of air, energy, and other regulatory bodies, as envisioned in the EPA proposal. To ensure compliance with a rate-based standard, all a state needs to do is monitor fossil fuel use and collect the money. In addition, states can easily expand their tax base when and if EPA regulates additional source categories under section 111(d).

Consistent with the language of the Clean Air Act, with EPA's public commitments and with Supreme Court precedent,[40] states should be free to comply with section 111(d) rules using policies of their own choosing, so long as the policies achieve the goals set by EPA. Taxing carbon is an effective, simple, pragmatic, and cost-effective approach to reducing CO_2 emissions. EPA should allow states to use carbon taxes as a compliance strategy. We explain in our comments to EPA that although the EPA proposal as written will allow states that wish to adopt a carbon excise tax to do so, it inadvertently precludes the simplest option of imposing the tax liability on electric generating units themselves. Instead, the proposal's expanded definition of "emission standard" would require states to place the statutory incidence of the tax only on entities upstream or downstream from regulated sources.

EPA could remove this barrier in two ways:

1. EPA could change the section 111(d) implementing regulations to clarify that any measure that is enforceable and reduces emissions qualifies as an "emission standard." Current regulations allow only for rate based standards, allowance systems, or equipment specifications; or
2. EPA could revise the expanded definition of "emission standard" in the proposed rule to include reductions in emissions caused by regulation of any affected entity, including electricity generating units themselves. The current proposal somewhat paradoxically credits any effective policy that applies to entities other than power plants but only a limited set of options that apply directly to the plants themselves.

These changes are straightforward, but the first is more broadly applicable. It would apply not only to power plants and carbon dioxide but also to other source categories and pollutants, thus assuring states that the flexibility EPA is offering for power plants will extend to other source categories in future emissions guidelines. EPA has said that it wants to give states maximum flexibility in meeting targets in the Clean Power Plan. We suggest simple ways for EPA to provide states full flexibility, including the option of using a carbon tax to achieve required reductions if their local circumstances and politics support that approach.

Question 8: Response by Peter Barnes
Entrepreneur and Author of With Liberty and Dividends for All

EPA should allow states to achieve their carbon intensity targets through an upstream cap-and-permit system, with all first sellers of carbon or carbon-based electricity required to buy permits, all permits auctioned and all auction revenue used for per capita dividends to the state's legal residents (people, including children, who are legal US residents, have Social Security accounts, and have lived in the state for a year or more). The states ideally could coordinate their systems with other states in their region, as in the northeast Regional Greenhouse Gas Initiative.

[40] See http://www.brookings.edu/research/papers/2014/05/22-state-tax-regulating-greenhouse-gas-clean-air-act-morris.

Each year the number of permits would decline until the state's or region's target is met. Only actual fossil fuel or electricity sellers could acquire permits (that is, no traders or speculators), and no offsets or other forms of leakage would be allowed. The efficacy of such a cap on first sellers lies in the fact that, if carbon doesn't come into a region, it can't go out. EPA would be able to track the effect of the cap by the number of permits sold.

Distribution of the dividends should not be made by utilities as a credit against energy bills, as is currently the practice in California. While a utility credit system is better than no rebates at all, a direct payment system would be much better. For example, equal dividends could be wired electronically to every resident's bank account or debit card. This could be done through the Social Security Administration or a state agency using the Internet and/or banks to enroll eligible recipients. This is the approach that Alaska has successfully used to distribute its Permanent Fund dividends.

The reason for distributing dividends via direct payment rather than via utilities is that credits against utility bills mask the higher cost of energy and thus reduce the signal to conserve. Utility credits also allocate payments per meter rather than per capita, and don't effectively remind state residents that they are receiving dividends that will rise along with energy prices. Such public awareness is essential for maintaining political support for phasing out carbon over the decades it will take to do so.

An upstream cap-and-permit system as described above is preferable to a carbon tax or fee without an upstream cap—even if the fee is accompanied by dividends—because it sets the quantity of carbon that can be burned rather than the price. There is no way to know in advance the effect of a carbon price on the quantity of carbon burned; innumerable other variables are involved. On the other hand, with a leak-proof upstream cap, it is possible to foresee and control the future quantities of carbon burned, regardless of rises and dips in carbon prices.

And, an upstream carbon cap would not be difficult to administer. It would apply not to emitters but to suppliers—the same companies a carbon tax would apply to, the difference being that the prices paid by the companies would be set by auctions rather than government. California and the Regional Greenhouse Gas Initiative have shown that such auctions can be conducted fairly and efficiently. If some predictability in prices is desired, a floor price on permits could be included.

As for the argument that permit revenue could be more effectively spent by state governments on conservation programs than by individuals who receive dividends, the fact is that it is the cap itself that reduces emissions, not the spending of revenue on particular programs. Such spending may shift reductions under the cap from one sector of the economy to another, but they are unlikely to increase reductions above the level set by the cap.

Question 8: Response by Roberton Williams III
Senior Fellow and Director of Academic Programs, Resources for the Future

See page 13.

9. **Could an alternative compliance payment help states comply with EPA's Clean Power Plan and, if so, how might it be designed and implemented?**
   Under EPA's Clean Power Plan, states will need to make long-term planning decisions even though significant uncertainties exist about the costs of complying with the rule. Could an alternative compliance payment (ACP), which might allow an electricity producer to pay an emissions charge in lieu of complying with a particular policy, aid in planning and allow states to better manage electricity prices and electricity system reliability? How might an ACP be designed and implemented

so that its use ensures compliance with the Clean Power Plan?
Posted November 21, 2014.

Question 9: Response by Dallas Burtraw, Darius Gaskins Senior Fellow, Resources for the Future and Karen Palmer, Research Director and Senior Fellow, Resources for the Future

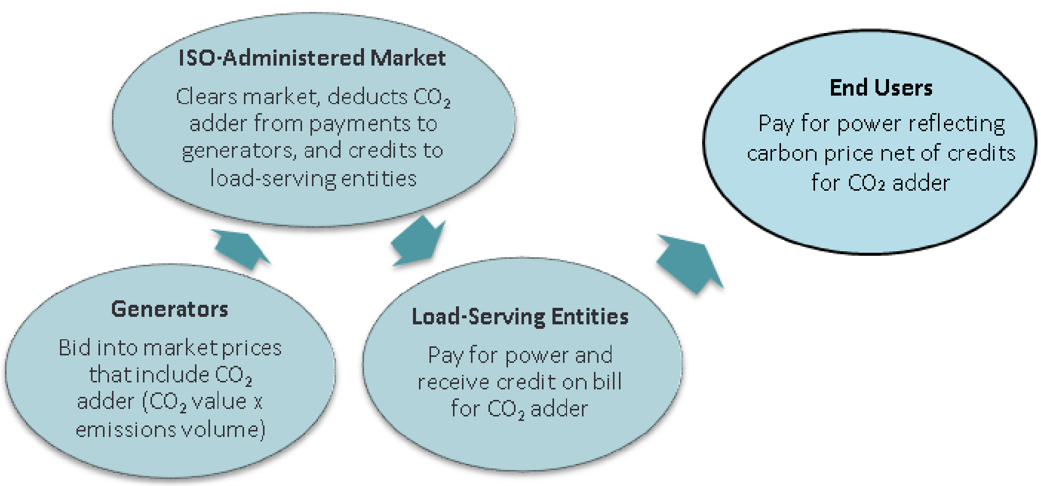
See page 29.

Question 9: Response by Kathleen Barrón
Senior Vice President of Federal Regulatory Affairs and Wholesale Market Policy, Exelon Corporation

Yes! One version of the alternative compliance payment concept would be to use existing centralized dispatch programs—such as those in use by regional transmission organizations (RTOs) —to co-optimize reliability and greenhouse gas reductions by requiring fossil generators to include a cost per ton of carbon in their electricity bids. EPA could facilitate this approach by including in the final rule a carbon price that, if imposed by a state on its generators during the compliance period, would satisfy EPA that the state would achieve sufficient reductions during that period. In return, the state would receive a "safe harbor" from compliance with its emissions rate or emissions cap for the period during which the carbon price was imposed on the state's generators. Any state that opted into the safe harbor RTO dispatch approach would be both allowed and required to focus on crafting a long-term glide path to achieve EPA's final emissions goals by 2030.

The Mechanics

In states with organized markets that opt in, the RTOs would dispatch the system as depicted in the figure below.



The independent system operation (ISO) would return the greenhouse gas fees collected to load-serving entities in the corresponding state, according to the number of megawatt-hours served. The state would direct its load-serving entities how to use the greenhouse gas fees, whether for mitigating customer bill impacts or for other state policy objectives, such as funding energy efficiency or demand response programs.

The same principles behind the RTO dispatch concept could be applied outside organized markets. Vertically integrated utilities similarly determine least-cost dispatch among the owned or purchased generation sources available to serve that utility's native load, and customers pay rates based on the average fuel cost of the units dispatched plus fixed costs/return. To qualify for this safe harbor, a single utility dispatching multiple generation sources could agree to reflect a CO_2 adder in the dispatch cost of its fossil generation, much like the RTO would. The utility would then determine least-cost dispatch, including the CO_2 adder and customers would pay rates based on the increased average fuel cost associated with the units dispatched, again along with fixed costs/return.

Benefits of This Approach

- Provides states and customers with a viable voluntary approach to compliance
- Resolves, in part, the compliance questions surrounding the reasonableness and viability of EPA's building blocks by providing another pathway to compliance during the safe harbor period
- Ensures effective deployment of capital in coal units by allowing existing units with limited remaining operational lives to be fully utilized without additional costly retrofits
- Provides appropriate price signals to maintain and expand clean energy and natural gas utilization
- Guarantees electric reliability at both the state and regional level by linking greenhouse gas abatement to reliability dispatch
- Achieves significant greenhouse gas reductions at lowest cost
- Collected fees can be utilized to significantly offset customer costs or to achieve other public policy objectives at the states' discretion
- Allows states to achieve the benefits of coordinated regional action without negotiating comprehensive interstate compliance agreements—a complex process that might take years to complete
- Provides states and industry with longer compliance runway, allowing for improved planning and regulatory certainty

Question 9: Response by Robert A. Wyman, Jr.
Partner, Latham & Watkins LLP

Both states and sources will need compliance flexibility to minimize costs, assure reliability and avoid stranding assets. The National Climate Coalition (NCC) originally proposed two types of compliance options for electric generating units (EGUs), expecting EPA's proposal to be source- based consistent with prior section 111 rulemakings. The first recommended option would be traditional emissions trading of "emission reduction credits" from EGU over-performance, similar to lead credit trading under EPA's lead phasedown program, and of "system offsets" from surplus energy sector reductions achieved outside the EGU fence line. This degree of flexibility is needed because many EGUs will not be able to make even the required heat rate improvements, while the other building blocks are by definition beyond the control of individual EGUs.

The second recommended EGU compliance option is the alternative compliance payment (ACP). A source would use an ACP as a compliance alternative when on-site limitations or regulatory risks (e.g., the risks of triggering New Source Review) prevent on-site modifications and the costs of the credits and system offsets are higher than anticipated. The state would collect ACP payments and apply the funds toward any other building block (i.e., building blocks 2, 3, or 4) or other qualified energy sector opportunity. This would provide states with valuable energy sector financing, while providing sources compliance assurance at reasonable cost.

There is Clean Air Act precedent for such a cost mitigation instrument. The ceiling-price ACP concept was first conceived during the 1990 Amendments stakeholder discussions and formally articulated in President Clinton's July 1997 memorandum to EPA (62 Fed. Reg. 38421, 38429, July 18, 1997[42]) when EPA revised the National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. Recognizing that the revised standards could impose an unanticipated level of cost on regulated sources, the memorandum recommended an ACP option for sources facing control costs at or above a cost-effectiveness threshold to fund reductions from other sources and to stimulate new technologies. EPA has approved ACP programs under Clean Air Act Section 110 (see, e.g., SCAQMD Rule 1121, "Control of Nitrogen Oxides from Residential Type, Natural Gas-Fired Water Heaters").

As part of its final Clean Power Plan rulemaking, EPA should confirm the availability of the ACP option. Consistent with previous ACP applications, EPA also should confirm that the near-term price for a building block 1 ACP should reflect the upper bound of EPA's anticipated building block 1 cost (e.g., $6 to $12 per ton of greenhouse gas emissions reduction) because the ACP would serve as an alternative to building block 1–related reductions. As the building block 1 obligations are expected to occur in the early years of the program, the ACP price for that component of the program should not be expected to interfere with the potentially more costly measures contained in some of the other building blocks, the implementation of which is likely to occur over a longer period of time.

Given the stringency of building blocks 2 through 4 and EPA's interim and final goals, these ACP concepts should be expanded to cover the entire compliance burden facing EGUs. In addition to confirming state primacy in glide-path planning and timing, EPA should outline the conditions under which a state may use both banking and borrowing of reductions, as well as other mechanisms, such as market- and integrated resource planning–based development of clean replacement power, interstate trading, and multi-state energy planning. These tools will protect against the reliability, price, and market distortions that are likely to result from excessive compliance costs, while also enabling states to optimize energy planning and ensure that near-term commitments don't compete with longer-term, lower-carbon strategies through the unintended lock-in of more carbon intensive investments.

[42] See http://www.gpo.gov/fdsys/pkg/FR-1997-07-18/pdf/97-19201.pdf.

Appendix B

May 7, 2012

The Role of Biomass and Natural Gas Co-Firing in GHG Performance Standards

By Matt Woerman, Dallas Burtraw, and Anthony Paul[1]

1. Overview

One way to reduce carbon dioxide emissions rates (CO_2/MWh) from existing coal-fired power plants is to cofire with biomass or natural gas. This paper explores the consequences of giving credit to cofiring with either or both those fuels in order to comply with an emissions rate performance standard. We describe how this technology is represented in the Haiku electricity market model of the electricity sector and consider the sensitivity of the model to opportunities for cofiring. To investigate this issue we solve the model over a 25 year horizon under a small set of representative policy scenarios.

In brief we find the following:

- Cofiring with either biomass or natural gas reduces credit prices by about half.
- Cofiring with either biomass or natural gas reduces the amount of coal-fired capacity that retires, but it causes some of this capacity to be reconfigured for cofiring. Cofiring with natural gas or with natural gas and biomass results in more capacity reconfiguration than does cofiring with biomass alone.
- Cofiring of any type allows greater generation with coal than would occur otherwise. Biomass cofiring has the greatest positive effect. Cofiring provides additional generation from these facilities.
- Cofiring leads to a small increase in emissions overall (about 15 to 20 percent of reductions), with little difference between the type of cofiring that occurs.
- There is little difference in efficiency investments across scenarios. It is always near the maximum possible due to the stringency of the scenarios. This result may not be robust to less stringent policies.
- Consumers see a benefit from biomass cofiring, which reduces the electricity price change by almost half. Natural gas cofiring has no effect on electricity prices.
- Consumers see no benefit from the opportunity to cofire with natural gas but producers benefit slightly.

Three other points deserve consideration. There is a considerable increase in biomass cofiring by 2020 in the baseline, that is, even in the absence of an emissions rate performance standard. (There is no

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natural gas cofiring in the baseline.) Consequently, if the stringency of a performance standard were based on a historic measure assuming a historic emissions rate for generation at coal-fired power plants, and if the standard gave credit to biomass cofiring because of its presumed lower life cycle emissions, it would give credit for some reductions that would have happened *anyway* even in the absence of the standard. Consequently, to achieve the same emissions reductions and give credit for biomass cofiring the standard might need to be tighter than it would be otherwise.

Second, although there is insufficient space in this analysis to explore regional issues, potentially important differences emerge at the regional level, especially with respect to the change in electricity prices. Regions where electricity prices tend to increase the most in the absence of cofiring appear to be regions where an important amount of cofiring with biomass occurs, which tends to reduce electricity price changes and also is likely to deliver economic benefits to suppliers of biomass in those regions. Consequently, biomass cofiring may provide benefits for consumers and fuel suppliers in those regions. In contrast, as noted above and discussed below, natural gas cofiring may offer few benefits for consumers but may offer benefits for producers.

Third, all of the biomass cofiring that we observe in the model uses waste resources including forest and mill residue, agricultural waste and municipal waste. Although it is available in the model, there is no use of dedicated energy crops for biomass cofiring because energy crops have a substantially greater cost. Because we assume the amount of biomass cofiring that is possible at individual plants is constrained by the boiler technology, there is sufficient waste resource to meet all demand. This means that, at least in this analysis, the controversy about actual life cycle emissions associated with dedicated energy crops is not instrumental.

2. Scenarios

The Haiku electricity market model includes the capability to cofire biomass and natural gas at coal-fired plants. Cofiring involves partially substituting another fuel, in this case biomass and/or natural gas, for the usual coal input in the plant's boiler. The decision to cofire is based on the relative costs of different fuels, the cost of converting the existing facilities to use the cofired fuel, and potentially the benefits of reduced costs for emissions and for credits under an emissions or heat rate performance standard. Biomass cofiring has the additional potential benefit of qualifying for a renewable production or investment tax credit or renewable portfolio standard. Within Haiku, plants cofire up to the point where the marginal costs and benefits of cofiring are equal, subject to constraints on the amount of capacity that can cofire at each plant. Further detail on how cofiring is represented in the model is provided in the appendix.

To investigate the sensitivity of the electricity sector to the opportunity for cofiring, this analysis assumes the implementation of performance standards for existing steam electric boilers under the Clean Air Act. We assume such standards would require a reduction in the fleet average emissions rate that would be implemented in 2020 and maintained thereafter. For coal-fired plants the standard requires a reduction in the generation-weighted fleet average emissions rate of 7.5 percent from the rate that occurs in the baseline in the model for 2020. Coal plants can trade emissions rate credits among themselves and with oil and gas steam generators to achieve this emissions rate reduction. Oil and gas steam generators are held to their generation-weighted average emissions rate across both fuels. There is no reduction in the average emissions rate required from this group of units; however the change in their utilization could contribute to achieving the overall emissions rate standard.

Emissions rate credits are assigned to coal steam units at a benchmark emissions rate of 1919 lbs. CO_2/MWh, which is 7.5 percent below the baseline in 2020.[2] Oil and gas units are assigned credits at a benchmark emissions rate of 1616 lbs. CO_2/MWh that is the generation-weighted average of their observed emissions rates in the baseline in 2020.

One way to understand the tradable emission rate program, and the way it is implemented in the model, is that credits are earned at the benchmark rates (CO_2/MWh) for each MWh of generation for each fuel, and are surrendered at the actual rate for each unit of generation. If a plant has an emissions rate below its benchmark standard it earns more credits than it needs for compliance and the extra can be sold to plants with rates above the benchmark. The credit price equilibrates such that the demand and supply of credits are equal.

In the model coal-fired plants have the opportunity to reduce emissions rates by implementing efficiency measures at a cost that grows with the level of the investment. The cost and schedule of opportunities are drawn from Sargent & Lundy, L.L.C. (2009) and the way these potential efficiency improvements are implemented in the model is described in Burtraw et al. (2012a). In general, the more efficient a plant is the more expensive will be its investment opportunities and the fewer opportunities will be available to it.

The ***baseline*** scenario does not include the CO_2 emissions rate performance standard described above. It does include the Mercury and Air Toxics Standard (MATS). It does not include the Cross State Air Pollution Rule; instead Title IV (CAIR) remains in effect for sulfur dioxide and CAIR remains in effect for nitrogen oxides. Detail on the way MATS is modeled and other aspects of the Haiku model are presented in Burtraw et al. (2012b). In the model, biomass cofiring is allowed and occurs in the baseline but natural gas cofiring is not allowed.

Four policy scenarios reflecting options for cofiring are modeled. In every scenario including the baseline the possibility for cofiring is available; the difference among the scenarios is whether it is given a credit in compliance. In the ***none*** scenario, cofiring is not given credit in compliance. Where biomass cofiring occurs, the emissions rate for a plant is calculated based on the observed emissions leaving the stack divided by the heat input from coal and biomass. There is no credit given for the possibility that lifecycle emissions for the biomass fuel are less than what are observed leaving the stack. Natural gas cofiring is not allowed.

In the ***biomass*** scenario, cofiring with biomass at coal plants is advantaged by assigning it an emissions rate of 0 lbs./MWh. This rate reflects the expectation that biomass production takes CO_2 out of the

[2] This value is the emissions rate of coal-fired generation at coal units and does not include biomass or natural gas cofiring at those units.

atmosphere, so the growth and burning process is carbon neutral. Although there is some controversy with respect to life cycle emissions from biomass due to land use conversion for biomass production, in the model results we do not find this to be a likely problem because all biomass that is used in cofiring comes from waste. There is ample supply of waste to match the demand for biomass cofiring in all our scenarios in each region of the country.

In the ***natural gas*** scenario, cofiring with natural gas is allowed at coal plants and it is advantaged by assigning it an emissions rate equal to the emissions observed leaving the stack divided by the heat input. That emissions rate for natural gas used at a plant varies based on the heat rate of the plant, but it is roughly 55 percent of the rate observed for coal-fired generation at the same plant.

The fourth scenario gives an advantage to ***both*** biomass and natural gas cofiring at coal plants in the ways described above.

3. Results

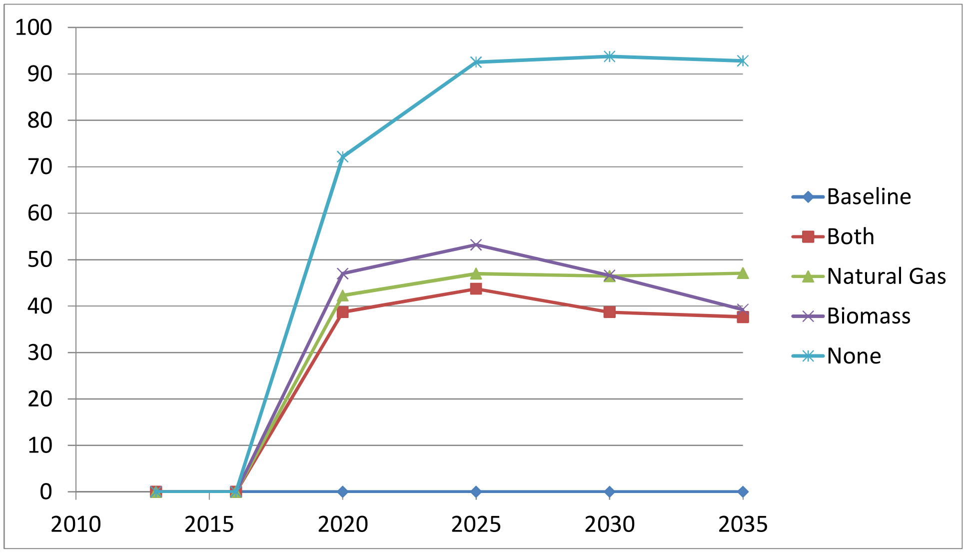
The model is solved through 2035. We focus most of our attention on 2020, the year the policy takes effect.

Credit prices

Credit prices under the emissions rate standard are denominated in dollars per unit of emissions ($/ton CO_2).[3] All values in this paper are in 2009 dollars. The opportunity for cofiring with either biomass or natural gas or both has an important effect on the credit price, causing it to fall roughly by half compared to the none scenario that does not advantage cofiring. Figure 1 illustrates that credit for cofiring with both biomass and natural gas leads to the lowest credit price, but it is almost identical as when only one of these fuels is credited. The two fuels substitute strongly in cofiring with respect to their influence on the credit price.

[3] Credits are awarded and surrendered based on the plant's CO_2 emission rate (ton CO_2/MWh) and the plant's level of generation (MWh), so the price is denominated as $/(ton CO_2/MWh)/MWh, which is equivalent to $/ton CO_2.

Figure 1. Credit prices ($/ton CO2, $2009)

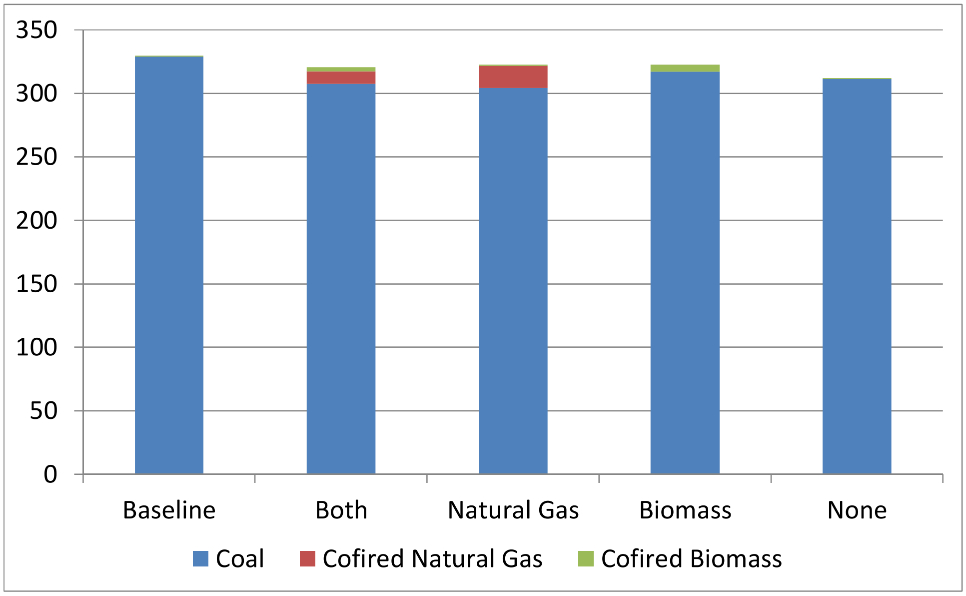


Capacity

The model assumes that capital investment involving some reconfiguration of the boiler is necessary to enable cofiring. Hence, for accounting purposes capacity at a coal-fired plant that is diverted to cofiring is labeled as a different technology; for example, one GW of capacity used for natural gas cofiring implies one less GW of coal capacity.

Figure 2 illustrates the capacity at coal-fired plants in 2020. The height of each color is the amount of capacity at coal plants that is configured to fire each type of fuel. The total height of each bar is the total capacity at coal plants. The difference between the baseline and none scenarios results strictly from retirement, which totals almost 20 GW in 2020. The opportunity for biomass cofiring reduces the amount of retirement and enables about 10 GW of capacity to survive in 2020, 6 GW of which are reconfigured to cofire biomass. This capacity change is due to the lower cost of compliance when biomass cofiring is available. The cost is lower both at plants that cofire and those that do not because they also benefit from the lower credit price.

Figure 2. Capacity at Coal Plants in 2020 (GW)



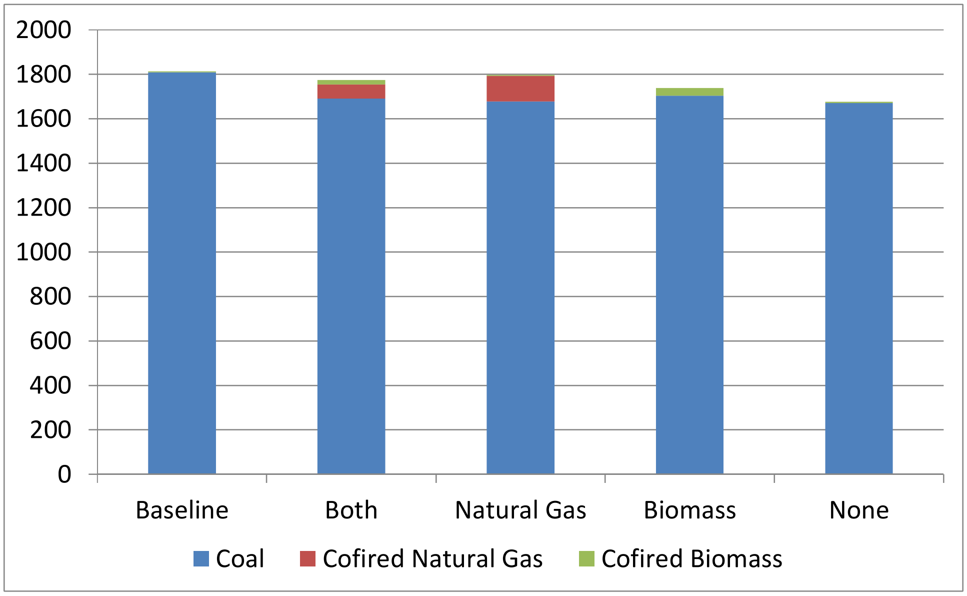
When natural gas cofiring is available, either with or without biomass cofiring, the total capacity at coal plants is similar to when biomass only is available, although the amount of capacity reconfigured for cofiring increases. This results in less capacity available for firing coal than when no cofiring is available. Natural gas cofiring alone has the greatest effect on cofiring capacity with close to 20 GW of capacity converted to natural gas cofiring.

When both fuels are advantaged, less capacity is converted for each type of cofiring than when only one fuel is advantaged; 10 GW are reconfigured for natural gas cofiring and 3 GW for biomass in 2020. This results in a reduction from the baseline of more than 20 GW of capacity configured to fire coal. In later years the total capacity at coal plants is roughly equal to capacity in 2020, although the amount of capacity reconfigured for cofiring increases slightly over time.

Generation

Figure 3 is similar to Figure 2 but displays the amount of generation occurring at coal plants. Figure 3 illustrates that the largest reduction in coal generation and total generation at coal plants, about 140 TWh in 2020, occurs when no cofiring is allowed. The introduction of cofiring leads to small increases in generation from coal, which is likely due to the reduction in credit prices when low or no emissions generation possibilities are part of the trading system, as well as additional generation from the cofired fuels.

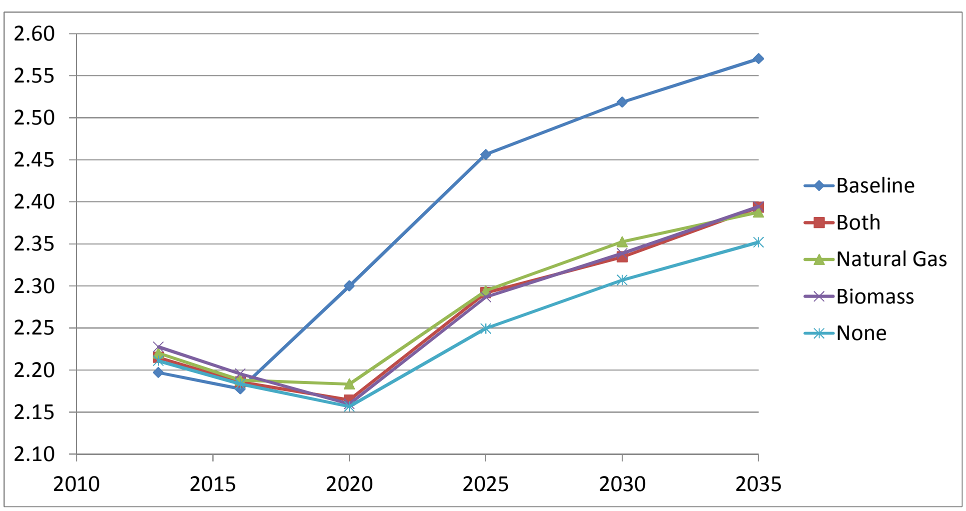
Figure 3. Generation at Coal Plants in 2020 (TWh)



Emissions

The largest change in emissions is also when no cofiring is allowed. Again, this is because the opportunity for cofiring reduces the credit price and the cost of compliance for coal facilities. In 2020, the total emissions reduction from all fossil generators is about 140 million tons. Cofiring leads to a small increase in emissions overall. The biggest difference occurs when natural gas cofiring is allowed, when emissions in 2020 increase by about 25 million tons, or 18 percent of the reductions that occur when no cofiring is available. In later years there is little difference among the three cofiring scenarios as each scenario undoes roughly 15 to 20 percent of the reductions achieved when no cofiring is available.

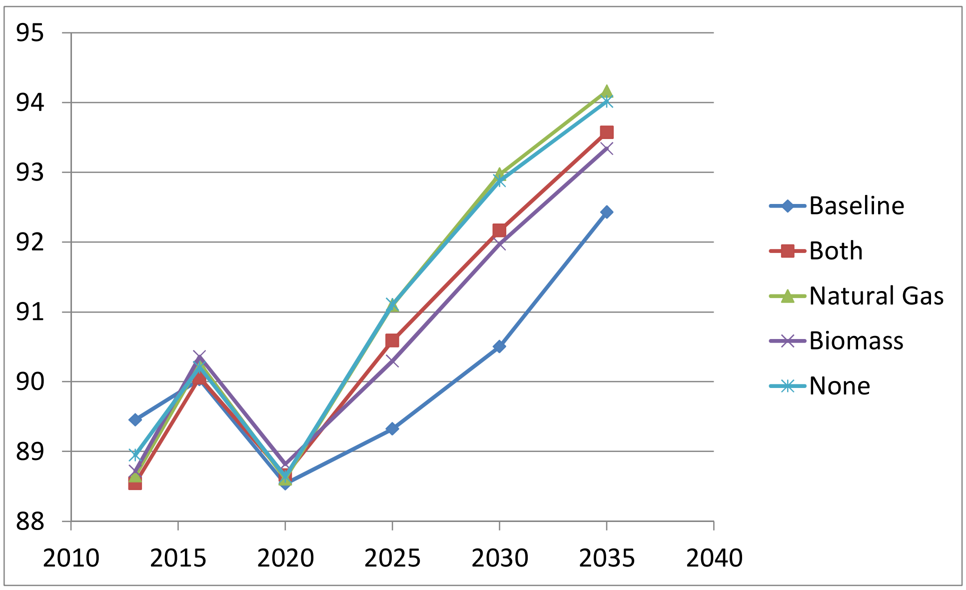
Figure 4. Emissions (billion tons CO_2)



Electricity Price

The difference in electricity prices among scenarios including the baseline (no emissions standard) is insignificant in 2020. Figure 5 illustrates that in 2025 a difference emerges, with the standard raising electricity prices above the baseline. When no cofiring is advantaged the price increases by approximately $2/MWh in 2025 and beyond. This increase is reduced by about half when biomass cofiring is advantaged, regardless of whether natural gas cofiring is also advantaged. The opportunity to cofire with natural gas in combination with biomass has almost no effect on electricity price compared to cofiring only with biomass. The opportunity to cofire with natural gas alone has almost no effect on electricity price compared to no cofiring. In other words, the opportunity to cofire with biomass rather than with natural gas is the policy parameter that affects electricity price. The data reveals this is true on average in both regulated and cost of service regions.

Figure 5. Average National Electricity Price ($/MWh, $2009)



As noted previously, when cofiring is advantaged the credit price is reduced roughly by half. However, the change in the credit price is not necessarily passed through as a change in electricity price. One reason is the credit price has little direct effect on electricity prices. For the nation the net allowance burden is zero because the sales and purchases of credits are equal. In cost of service regions where price is based on average cost of service the sales and purchases of credits wash out in determining electricity price. In these regions only net sales (or purchases) from out of the region matter in determining electricity price. In competitive regions the price of a credit is part of the variable cost of generation, but this applies only to the difference between the benchmark and the actual emission rate for the unit, so the net effect may be small. Moreover, in most regions most of the time coal fired plants are not at the margin and are not determining electricity price.

Another component of cost that might affect electricity price is the investment in energy efficiency at coal plants. Across all four policy scenarios there is about $4 billion ($2009) investment annually by 2025 and beyond. The opportunity to cofire affects this level of investment by only a little. Investment in energy efficiency is about $150 million less when both cofiring methods are advantaged compared to when neither is. The reason the change in the current analysis is small has to do with the stringency of the standard. Most of the coal plants are purchasing near the maximum amount of possible energy efficiency improvements under all the scenarios, so cofiring leads to little change in investment in efficiency.

However, one difference among scenarios is that in the natural gas cofiring scenario there is a significant substitution in generation from natural gas plants to generation with natural gas at coal plants, with a commensurate reduction in natural gas capacity. Nearly the same amount of natural gas is used for electricity generation when natural gas cofiring is advantaged and when no cofiring is advantaged. In contrast, biomass cofiring leads to greater generation with coal than does cofiring with natural gas (Figure 3), and less generation with natural gas. The reduction in gas generation has an effect on natural gas prices. Both the reduction in gas generation and the reduction in gas prices have an effect on electricity prices.

Producer Profits

Producer profits are affected to a small degree by the opportunity to cofire with natural gas. As we noted electricity prices do not respond to the opportunity to cofire with natural gas but there are cost savings associated with less retirement of existing capacity and construction of new capacity. These savings appear to accrue to producers, who enjoy slightly greater profits in total under the natural gas cofiring scenarios than when no cofiring or just biomass cofiring is allowed.

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Appendix: Background

This appendix provides further background on how cofiring is conceived and modeled.

Costs of Cofiring

When a coal plant cofires, it incurs two costs. The first is a capital cost associated with converting the existing facilities to use the cofired fuel. The capital cost for biomass cofiring comes from EPA (2007). These data include different costs for different unit capacities and firing types. The costs are applied to each constituent plant and then averaged (weighted by capacity) to calculate the cost for a model plant in Haiku. The capital cost for natural gas cofiring comes from EPA (2011). There are two components to the capital cost for natural gas cofiring: converting the existing facilities and connecting the plant to a gas pipeline. For the former, EPA provides two costs for different firing types, and Haiku uses the capacity-weighted average of these costs at each model plant. For the latter, EPA provides plant-specific costs to connect to the pipeline that provide the basis for estimated costs that are capacity-weighted and averaged to provide a unique estimate for each model plant.

The second cost is the variable cost of burning the cofired fuel instead of coal. Both biomass and natural gas typically have a higher price per Btu than coal, so a plant that cofires with either of these fuels will see a greater variable cost of generation. However, fuel prices are solved endogenously within Haiku, so it is possible that the price of coal could be greater than the price of biomass or natural gas in some region of the country. In this case, cofiring would actually lower the total fuel cost, so this cost component would be a net benefit rather than cost.

Benefits of Cofiring

One benefit of cofiring is a reduced cost of emissions. When emissions of a pollutant incur a cost, either from a tax or a cap-and-trade program, reducing a plant's emission rate will reduce its variable cost. Both biomass and natural gas are typically less emissions-intensive than coal, so cofiring will typically reduce variable costs. In a few cases, especially emissions of nitrogen oxides, the emission rate of biomass may be greater than that of coal, in which case cofiring would actually impose an additional variable cost.

The calculation of greenhouse gas emissions associated with cofiring is an explicit consideration in Haiku. When natural gas is cofired with coal, the heat rate is calculated as the sum of heat input (Btu) from both fuels divided by the electricity output (kWh), and the emissions rate is calculated as emissions (tons) divided by electricity output. When biomass is cofired with coal the calculation depends on an explicit assumption about the life cycle emissions associated with the use of biomass. The calculation of life cycle emissions of biomass is a controversial and unsettled research issue, but that controversy surrounds primarily the use of dedicated energy crops. In Haiku the biomass used for cofiring is constrained to waste product from agriculture, municipal, forest or mill residue because they have lower costs than dedicated energy crops. Under the assumption that combustion of waste biomass does not contribute to life cycle greenhouse gas emissions, the heat input or emissions associated with the biomass is not included in the calculation of the heat rate or emissions rate. However, this assumption can be changed in Haiku to model policies that would count a portion or all of the heat input and direct emissions from biomass.

Another benefit of cofiring occurs under a heat or emissions rate performance standard. This can take the form of an inflexible or traditional standard where every plant must operate under a specified heat/emissions rate, or a flexible or tradable standard where the fleet-wide generation-weighted average heat rate must meet a specified benchmark level. In either case, cofiring could be allowed as a compliance option that would reduce heat and or emissions rates as described above. Under an inflexible standard, cofiring will reduce the level of investment in generator efficiency required to bring a plant into compliance with the policy. Under a flexible standard, the fleet-wide average will be met through the issuance and trade of credits (in Haiku these are called generator efficiency credit offsets, or GECOs). A reduced heat or emissions rate that results from cofiring will reduce a generator's GECO burden and variable cost of generation.

A benefit of biomass cofiring in particular relates to policies that specifically target renewable power. Biomass is subsidized as a renewable fuel under the current federal renewable production tax credit and under most state renewable portfolio standards. In the presence of these subsidies, biomass cofiring would reduce the variable cost of generation.

Cofiring Equilibrium Outcome

As discussed above, cofiring biomass and natural gas at a coal-fired plant imposes several costs on the plant and also provides several benefits. It is important to note that these costs and benefits differ for biomass and natural gas and vary over time as prices change. Haiku calculates the marginal cost and marginal benefit of cofiring capacity at each coal model plant, and these calculations are performed separately for each cofiring fuel and for each year. For each coal plant in each year, Haiku equates the marginal cost and marginal benefit of cofiring each fuel, so the plant will cofire up to the point where these measures are equal, subject to several constraints, which are discussed below.

Constraints on Cofiring

The cofiring capacity at each coal model plant is subject to several constraints. The first is simply that the sum of biomass and natural gas cofiring cannot be greater than the total capacity of the model plant. In most cases, biomass cofiring will be cheaper than natural gas cofiring, so Haiku assumes that biomass cofiring occurs first, and any remaining capacity can cofire natural gas.

The second constraint is that the amount of biomass cofiring that can occur at individual facilities varies with the boiler type. The amount also depends on unit capacity, drawing on restrictions from EPA (2007) about the geographic availability of biomass at individual facilities due to transportation costs. These constraints are incorporated as capacity-weighted averages at the model plant level in Haiku.

The third constraint is temporal and has two components. First, once capacity has been converted to allow for cofiring, it cannot be reverted back to coal-only operation, and capacity cannot be converted from one type of cofiring to another. So if an amount of biomass cofiring is economical in one year, all future years must have at least that amount of biomass cofiring capacity. The same is true for natural gas cofiring. This constraint imposes a lower bound on the amount, for each fuel, of cofiring allowed at each coal model plant in each year. Second, capacity cannot be converted to allow for cofiring if it will be retired in the future or if future retirement could force the cofired capacity to exceed the cost-based constraint discussed above or force total cofiring to exceed total capacity as discussed above. For example, if half of a coal model plant will retire before the end of the simulation time horizon and only 10% of the plant can cofire biomass, then in the early years, up to half of the capacity can cofire natural gas and up to 5% can cofire biomass. This constraint imposes an upper bound on the amount, for each fuel, of cofiring allowed at each coal model plant in each year.

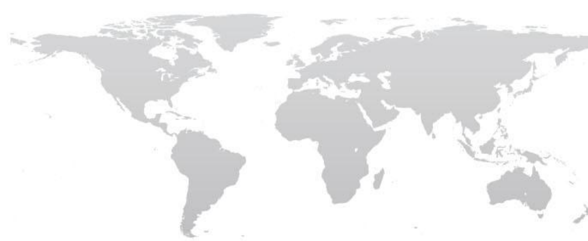
ISSUE BRIEF

Appendix C

Preserving Flexibility: Comments on the US Environmental Protection Agency's Carbon Existing Source Performance Standards

Nathan Richardson

RESOURCES FOR THE FUTURE



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Preserving Flexibility: Comments on the US Environmental Protection Agency's Carbon Existing Source Performance Standards

Nathan Richardson[1]

Key Points

- The US Environmental Protection Agency's (EPA's) decision to separate coal and gas power plants into different regulatory categories for its proposed New Source Performance Standards (NSPS) has little effect on those standards, but has important implications for upcoming existing-source standards (ESPS).
- The approach—split or combined categories—that the agency uses for its NSPS will almost certainly persist for ESPS.
- Other research indicates that switching from coal to gas generation is the largest and lowest-cost emissions reduction opportunity in the power sector.
- Combined categories are therefore crucial to the cost- and environmental effectiveness of ESPS. Trading between coal and gas that could incentivize this fuel switching is almost certainly legal if categories are combined, and almost certainly illegal if they are not.
- Combining coal and gas into a single category, as the agency did in its first NSPS proposal in 2012, would not reduce EPA's freedom to set standards, increase the rule's complexity, or add any significant legal risk.
- EPA should therefore combine coal and gas into a single source category in its final NSPS rulemaking.

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I. Introduction

In its January 8, 2014 proposal, *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*,[2] the US Environmental Protection Agency (EPA) requested comment on a variety of issues. Among these requests, EPA specifically solicited comment[3] on the relative merits of issuing standards separately for existing source categories (subparts Da and KKKK, covering primarily coal-fired steam and natural-gas combined cycle plants, respectively) versus combining the covered facilities into a new source category (subpart TTTT).[4] In the proposed rule, EPA "co-proposed" these two options, indicating its uncertainty over which option to select. This brief comment aims to address that question.

In short, the decision between these two options will have little effect on the substance, legal risk, or other aspects of the new source rule being proposed. However, the decision has far-reaching implications for future existing source guidelines and standards (assuming the decision is not revisited when those guidelines are written). Specifically, the ability of EPA and the states to use flexible tools for regulating emissions from coal and gas electric generating units (EGUs), including trading among sources, and EPA's ability to approve state standards that use these tools, very likely depend on the sources in question being grouped into the same source category.

II. Combining Source Categories: Effects on the New Source Rule

The decision to leave the existing Da and KKKK categories intact appears motivated by the agency's decision to abandon natural-gas combined cycle (NGCC) technology as the "best system of emissions reduction" for all fossil-fuel fired plants (that is, both category Da and KKKK). Merging the two categories was necessary to be able to identify NGCC as the "best system" for coal-fired plants, as the two technologies are currently separated into Da and KKKK. Now that, in the January 2014 proposal, EPA has decided to identify coal with carbon-capture and storage

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[2] 79 Fed. Reg. 1430 (2014).

[3] Id at 1454.

[4] This comment assumes that "source categories" as defined and described in §111 of the Clean Air Act, and as that term is used throughout the proposed rule, are analogous to the sets of sources defined in different subparts of 40 CFR Part 60 (such as Da and KKKK). In other words, all sources that are within the scope of subpart Da are in one source category, and all those within the scope of KKKK are in another category. While this is not explicitly stated in either the proposed rule or the CFR, it is consistent with past EPA practice and its interchangeable use of the terms "subpart" and "source category." See, e.g., footnote 55 of the proposed rule. The alternative interpretation—that sources could be in the same source category for §111 despite residing in different subparts in the CFR—is superficially legally plausible. Nothing in §111 requires EPA to maintain a 1:1 identity between source categories listed under §111(b)(1)((A) and the categories described in the CFR. However, §111(b)(1)(A) *does* require EPA to publish and maintain a list of source categories. If 40 CFR Part 60 is not that list (because it does not accurately represent the category divisions EPA is using), then it raises the question of where (and whether) any such list exists. Therefore the most reasonable interpretation is that 40 CFR Part 60 does constitute the list required by §111(b)(1)(A), and, therefore, that sources listed in separate subparts are indeed in separate source categories for §111 purposes.

(CCS) as the "best system" for new coal, combining the existing categories is no longer necessary to achieve EPA's desired substantive result in this rulemaking. However, while combining categories may no longer be necessary for EPA's new source proposal, doing so would have no significant negative effects on the proposal.

A. EFFECTS ON THE SUBSTANCE OF THE RULE

Whether EPA combines existing source categories Da and KKKK into a single new source category TTTT, or maintains the existing category definitions, will have no effect on the substance of the proposed rule. Combining categories imposes no limitations on the agency's ability to choose the rule's stringency, define the "best system of emissions reduction" that forms the basis of that stringency, or to set different stringencies, based on different identified systems, for various subcategories of sources. The best evidence of this is in fact EPA's own decision to co-propose combined and separated source categories. This is, correctly, presented as a separate decision, unrelated to the substantive elements of the rule described elsewhere in the proposal.

The proposal itself provides a good illustration of such subcategorization in the form of EPA's decision to differentiate between small and large natural gas turbines, all of which are within the scope of category KKKK.[5] If EPA were to adopt its co-proposed approach of combining categories Da and KKKK into new category TTTT, it could readily identify the coal-fired plants previously in category Da and the gas-fired plants previously in category KKKK as separate subcategories, and issue different standards for them just as it has proposed to do for small and large turbines.

In short, because of its ability to subcategorize, EPA's decision to issue different emissions-rate standards for coal and NGCC plants is wholly independent of its decision on the legal formalities of source category definitions.

B. EFFECTS ON LEGAL RISK

Adopting the co-proposed approach of creating new category TTTT does not create significant additional legal risk nor does it appear to add significant administrative burdens.

The Clean Air Act and longstanding EPA practice confirm that the agency has broad authority to define subcategories of top-level source categories, and to independently set the stringency and other aspects of standards for each subcategory. CAA §111(b)(2) states that "[t]he Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards." To "distinguish" among such subcategories must mean that EPA can assess the "best system" specifically for each category, leading to different determinations of

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5 See 79 Fed. Reg. 1430 at 1433 (2014).

stringency and other factors. Such subcategorization has long been EPA practice, though it is not required.[6]

The Clean Air Act also grants EPA authority to revise source category definitions. This grant comes without restrictions, time limitations, or instructions to consider any specific factors when making such revisions.

> The Administrator shall . . . publish (and from time to time thereafter shall revise) a list of categories of stationary sources. He shall include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.[7]

Combining existing source categories Da and KKKK into new category TTTT is just such a revision. Such a move would be a break with past agency practice in the sense that the category definitions would be changed, but this is not a valid legal argument that the agency lacks the authority to make the change. The explicit grant of authority to the agency in §111(b)(1)(A) to revise the list of source categories has little meaning if the agency is not empowered to change its category definitions.[8]

While the grant of authority in the CAA to revise the list of source categories is broad, it, like all grants of authority to agencies, is ultimately subject to review on arbitrariness grounds. If EPA combines source categories, therefore, it could in principle be challenged on the basis that its decision to do so is arbitrary. There appears to be little basis for such a challenge, however. The statute, again, gives no guidance or limitation on how specific or how broad categories must be. Categories Da and KKKK already combine many different types of sources with widely divergent characteristics. The best example is probably the inclusion of IGCC plants in category Da, despite the great deal of similarity between them and NGCC plants from an engineering perspective.

If this (and many similar classification decisions enshrined in existing source category definitions) are not arbitrary, it is difficult to see any remotely persuasive argument that combining Da and KKKK would be treated as arbitrary. The new category TTTT would include almost all fossil-fuel EGUs—arguably a much cleaner category definition than the current scheme. EPA, if necessary, can argue that the common traits of all TTTT sources—connection to the electricity grid, combustion of some mix of fossil fuels, emission of greenhouse gases (GHGs) and other

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[6] See *Lignite Energy Council v. United States EPA*, 198 F.3d 930 at 933 (noting that "[i]t was also within EPA's discretion to issue uniform standards for all utility boilers, rather than adhering to its past practice of setting a range of standards based on boiler and fuel type").

[7] CAA §111(b)(1)(A).

[8] An extremely narrow interpretation of §111(b)(1)(A) might be that it grants the agency authority to add (or perhaps) remove classes of sources from the list of source categories, but does not grant authority to alter the boundaries between categories once they are listed. There is no apparent basis in the statute for such an interpretation, and, given *Chevron* deference, no court could force such an interpretation on EPA.

pollutants, and other factors, justify their inclusion in the same source category. For a court to reject this rationale would be extremely unlikely given the statute's broad grant of authority and courts' deference to agency decisions under the *Chevron* doctrine.[9]

C. EFFECTS ON ADMINISTRATIVE COMPLEXITY

Combining source categories Da and KKKK into new source category TTTT for purposes of this rulemaking does not appear to add any significant administrative burden or complexity.

First, combining categories likely has no effect on existing performance standards for other pollutants that apply to categories Da and/or KKKK. In fact, EPA need not alter the existing definitions of category Da or KKKK at all. Nothing in the statute requires source categories to be mutually exclusive. Creation of new category TTTT, therefore, does not require EPA to redefine Da and KKKK as subcategories of TTTT for all pollutants and performance standards, past and future. TTTT can be used as the relevant source category for GHG performance standards and any future rules where combining coal and gas-fired power plants is advantageous or appropriate, while Da and KKKK can persist as the relevant source categories for existing (and future) performance standards for other pollutants.

Even if EPA concludes, for legal or merely administrative reasons, that it would be best to keep category definitions consistent across performance standards applying to different pollutants, major changes to non-GHG performance standards would not be necessary. Categories Da and KKKK can easily be redefined in the Code of Federal Regulations (specifically, 40 CFR Part 60) as subcategories of TTTT without affecting these past rules.

Some may argue that if EPA creates a new source category it must make a new endangerment finding for that category. EPA discussed this issue in its original April, 2012 proposal for GHG new source performance standards (NSPS),[10] arguing that such a finding is not required, and that even if it were, the 2009 GHG endangerment finding and other actions suffice to meet the requirements of a category TTTT endangerment finding. EPA made similar arguments in its January 2014 proposal,[11] and they remain persuasive. In short, combining source categories is unlikely to require EPA to issue an additional endangerment finding, and even if it does (or if EPA decides to issue such a finding out of caution), the process is likely to be trivial.

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[9] Indeed it is hard to see how any category definition or redefinition would be rejected by a court on arbitrariness or other grounds, short of a decision by the agency to group all sources in the economy into a single category, or to create a separate category for each source. Either approach would, arguably, violate Congress' implied intent for EPA to divide sources into groups.

[10] See 77 Fed. Reg. 22392 at 22397 (2012).

[11] See 79 Fed. Reg. 1430 at 1453 (2014).

III. Combining Source Categories: Effects on Future Existing-Source Guidelines and Standards

A. LEGAL RISK ASSOCIATED WITH TRADING AMONG SOURCES

President Obama has committed EPA to propose guidelines for states to issue performance standards for existing fossil-fueled EGUs under §111(d) of the Clean Air Act by June of 2014. Those standards will almost certainly be far more significant in terms of emissions reductions and impact on the economy than the new source standards proposed here.[12] It is not unreasonable to assume that these guidelines will use the same source category definitions as the new source rule—there would be no apparent reason for EPA to use different category definitions for two rules proposed in such rapid succession for the same class of sources. EPA's specific request for comment on the impact of combining categories for existing-source standards further indicates that the agency intends to use the same category definitions for both rules.[13] Moreover, although states are the primary regulators of existing sources under §111(d), they are bound by EPA's source category definitions—the statute grants the authority to define and revise source categories only to EPA.[14]

EPA's decision on whether to combine coal and gas-fired EGUs into a single new source category TTTT in this new source rulemaking therefore has far-reaching implications for the design of existing source performance standards (ESPS). In the ESPS guidelines, EPA may make a "system-based" interpretation of the "best system of emissions reduction" language such that some flexible compliance system including trading, banking, and averaging is defined as the "best system", rather than a technological system as in past §111 performance standards.[15] The "best system" is determined separately for each source category, implying that trading, banking, and averaging are only possible within each source category.

This is due to the source category–focused design of §111. If sources in different categories are allowed to trade emissions credits with one another, the inevitable result is that one category will

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12 See, e.g., Dallas Burtraw and Matt Woerman, *Technology Flexibility and Stringency for Greenhouse Gas Regulations*, Resources for the Future Discussion Paper 13-24 (2013), available at http://www.rff.org/RFF/Documents/RFF-DP-13-24.pdf (using modeling and economic analysis to show substantial emissions reduction opportunities from flexible existing-source standards).

13 See 79 Fed. Reg. 1430 at 1454 (2014).

14 On the other hand, §111(d) does not in fact mention source categories at all. It is possible, therefore, that they are not relevant for ESPS, and that states may regulate sources that fall within the scope of §111(d) (which, admittedly, does ultimately depend on them being classed into source categories) without reference to the boundaries between categories. This is an aggressive but not implausible interpretation of §111(d). See Nathan Richardson, *Playing Without Aces: Offsets and the Limits of Flexibility Under Clean Air Act Climate Policy*, 42 Environmental Law 735 at 753 (2012).

15 Most legal scholars find this approach to be consistent with the statute. See generally Gregory Wannier et al., *Prevailing Academic View on Compliance Flexibility under § 111 of the CAA*, RFF Discussion Paper 11-29 (2011), available at http://www.rff.org/Publications/Pages/PublicationDetails.aspx?PublicationID=21603.

overcomply with their standard and create excess credits, while the other will be a net buyer of credits and will therefore fail to comply. This is arguably inconsistent with the requirement that sources (or, under a broader "system-based" interpretation of "best system of emissions reduction", source categories) must comply with §111 performance standards. Moreover, EPA must determine the best system of emissions reduction separately for each source category. It would therefore be unable to consider emissions reduction opportunities in other source categories that would generate tradable credits when determining the "best system" and setting standards. The legal justification for trading and averaging among sources is that such trading is part of the "best system" for that source category, but that justification cannot extend to sources that lie outside the category and therefore the "best system." The most legally defensible basis for trading under §111 therefore is inadequate to support trading across source categories. Leaving current source categories (Da and KKKK, in this context) unchanged therefore either requires EPA to abandon inter-category trading, with serious effects on program costs and emissions reductions, discussed below, or requires it to assume significant and unnecessary legal risk in allowing intercategory trading.

EPA can easily resolve this issue by combining source categories, as I discussed in a 2012 paper:

> [T]the agency's categorization powers may allow it to achieve the practical equivalent of [inter-category] flexibility. . . . [T]he agency has the authority to revise source categories and create subcategories as it sees fit—it may "distinguish among classes, types, and sizes within categories." This probably allows EPA to expand existing categories, and possibly to create new "supercategories" encompassing multiple existing categories and relegating those existing categories to subcategory status. In this case, it would further appear to be able to define performance standards specific to each subcategory, but allow flexibility across the entire supercategory.[16]

EPA's 2012 proposed NSPS, published shortly after this paper was written, did take the approach suggested in this passage by combining categories Da and KKKK into new "supercategory" TTTT. This formal move, as discussed above, has no significant implications for the substance of the rule but avoids a significant source of legal risk when and if EPA (or any state) seeks to allow trading among sources currently split between categories Da and KKKK.

B. WHY TRADING MATTERS

The availability of trading among existing sources under §111(d) ESPS, and particularly the availability of trading between coal and gas plants—currently separated into different source categories—is crucial to the environmental and cost-effectiveness of the §111(d) program. Economic analysis indicates that allowing trading between coal and gas plants could achieve

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[16] Nathan Richardson, *Playing Without Aces: Offsets and the Limits of Flexibility Under Clean Air Act Climate Policy*, 42 Environmental Law 735 at 753 (2012).

nearly four times greater emissions reductions from the regulated sector at the same incremental cost, or the same emissions reductions at about 30 percent lower cost, relative to ESPS that do not allow coal–gas trading.[17] No other ESPS policy design decision is likely to approach this level of importance.

Further, EPA should remember that states, not EPA itself, are the primary regulators under §111(d). Even if EPA concludes that coal–gas trading is not a priority, states may have a different view. EPA should therefore structure its guidelines—including preliminary actions such as source category definitions—so as to give states the maximum flexibility possible. Combining source categories Da and KKKK for purposes of GHG performance standards increases states' flexibility by substantially reducing the legal risk associated with many types of trading or averaging, without requiring states to include such trading options.

Indeed, even if EPA determines that its preferred approach in §111(d) guidelines is to give only basic instructions to states so as to preserve their freedom to design standards as they see fit, the agency cannot avoid specific decisions on key threshold issues. The most important of these is source category definitions over which, as noted above, states have no control.

IV. Conclusions

EPA should return to the approach of the 2012 GHG NSPS proposal and combine the coal-fired sources in source category Da with the gas-fired sources in category KKKK, at least for purposes of GHG performance standards.

Doing so will have few, if any negative consequences for the new source rule. It will have no effect on EPA's freedom to set the stringency or other substantive aspects of the performance standards as the agency sees fit, nor on EPA's freedom to differentiate among fuel types in making those determinations. Combining source categories also does not create any significant legal risk, despite claims from industry advocates. EPA's authority under §111 is at its height when defining and revising source categories, restrained only by arbitrariness criteria. EPA can relatively easily establish a rational, non-arbitrary basis for a decision to combine source categories.

Moreover, combining source categories has a large impact on the options available to EPA and states in future existing-source standards. Combining categories greatly reduces the legal risk associated with allowing averaging and trading across sources currently in different source

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[17] See, e.g., Dallas Burtraw and Matt Woerman, *Technology Flexibility and Stringency for Greenhouse Gas Regulations*, Resources for the Future Discussion Paper 13-24 (2013), available at http://www.rff.org/RFF/Documents/RFF-DP-13-24.pdf (using modeling and economic analysis to show substantial emissions reduction opportunities from flexible existing-source standards).

categories. Analysis indicates that trading between coal and gas is the single most important determinant of the environmental and economic impact of existing-source standards.

No single decision EPA makes in crafting new-source standards has greater impact on the options available for limiting existing-source emissions. Because these existing-source standards are likely to be much more environmentally and economically significant than the new-source standards, and are likely to be the single most important element of President Obama’s Climate Action Plan, the decision EPA makes today on whether to combine source categories is arguably the most important decision the agency will make in this rulemaking.