Policy Brief

EPA's Proposed Clean Power Plan

Implications for States and the Electric Industry

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On June 2, 2014 the U.S. Environmental Protection Agency (EPA) announced its proposed performance standards for reducing carbon dioxide (CO_2) emissions from existing power plants under the Clean Air Act Section 111(d).[1] The proposed rule requires each state to reduce its CO_2 emissions rate from existing fossil fuel plants to meet state-specific standards (in pounds per MWh) starting in 2020, with a final rate for 2030 and beyond.[2] The EPA estimates that the rule will achieve a 30% reduction in CO_2 emissions from the U.S. electric power sector in 2030 relative to 2005 levels. Once the rule is finalized in 2015, states will have until June 2016 to submit initial state implementation plans, to be finalized by June 2017 for stand-alone plans, and by June 2018 for multi-state plans.

The proposed rule sets widely varying, state-specific targets based on four CO_2 emissions reduction measures. However, the rule is not prescriptive about how to meet the targets. Instead, each state's target can be met in a variety of ways, including through interstate cooperation and emissions allowance trading. It is not immediately obvious how costly it will be for each state to comply with the rules, as that will depend on the extent and relative cost of the CO_2 abatement alternatives available to each state (*i.e.*, the cost effectiveness of energy efficiency, renewables, and fuel substitution opportunities), and multi-state solution possibilities.[3]

In responding to the EPA's draft plan and estimating the potential impact on each state and utility, stakeholders will need to understand how these targets were derived, and to evaluate the reasonableness of the assumed emissions reduction measures. The potential for wide variation in cost impacts across states introduces equity concerns regarding the relative economic burden that the proposed rule places on each state and stakeholder group.[4] Further, in

1 See the EPA's proposed rule and technical documentation at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule

2 The EPA is only proposing rate standards for states with fossil fuel power plants. Vermont and the District of Columbia are not included in this rule because they do not have fossil fuel plants.

3 In general, introducing an efficient trading mechanism should reduce *net* compliance costs for all states involved by allowing states with high compliance costs to purchase CO_2 reductions and allowing states with low compliance costs to sell incremental abatement opportunities.

4 Similar equity concerns are likely to arise again later at the individual state or regional level, as state plans will affect how rates or emissions allowance credits are allocated to individual entities.

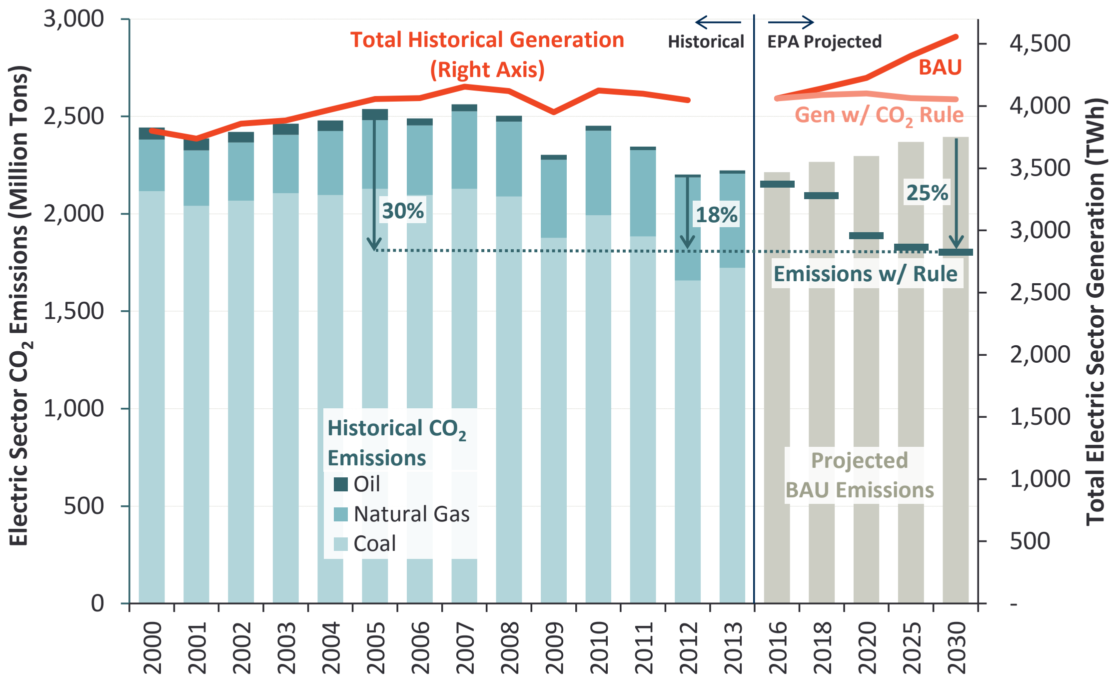
shaping compliance strategies, stakeholders will need to understand how adopting different compliance options would affect their expected costs, risks, and flexibility.

This policy brief provides states, plant owners, utilities, and consumer agencies with an overview of the proposed rule, and poses a set of key questions that will need to be answered to better understand how the EPA's Clean Power Plan will impact the industry going forward.

Electric CO_2 Emissions Projected to Drop 30% below 2005 Levels (25% below 2030 BAU)

The EPA projects that the proposed rule will achieve a 30% reduction in CO_2 emissions from the electric sector by the year 2030, relative to year 2005 levels. As shown in Figure 1, the electric sector has already realized substantial reductions in carbon emissions since 2005, due to: (1) low natural gas prices, which have caused coal-to-gas generation dispatch switching; (2) increased renewable generation, facilitated by federal tax credits and state renewable portfolio standards; and (3) low load growth, stemming from the economic recession and energy efficiency improvements. Therefore, the proposed rule is projected to achieve a more modest 18% reduction in CO_2 emissions below historical 2012 levels, or 25% below the EPA's business-as-usual (BAU) estimate projected for 2030.[5]

Figure 1
Fossil Generators' Historical and Projected CO_2 Emissions and Total Generation



Sources and Notes:

Historical emissions from EPA's Continuous Emissions Monitoring System (CEMS); historical generation from Energy Information Administration (EIA); projected generation and CO_2 from EPA's Integrated Planning Model (IPM), Base Case and Option 1: State scenarios.

Total generation under the Gen with CO_2 Rule case is lower than BAU due to the increase in energy efficiency.

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5 We report BAU numbers from the EPA's Base Case results from their Integrated Planning Model (IPM) in their Regulatory Impact Analysis (RIA) of the proposed rule. Details posted at: http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html

Four Building Blocks Comprise the "Best System of Emissions Reductions"

The basis for the emissions reductions in the EPA's proposed rule is a review of the Best System of Emissions Reductions (BSER) for reducing carbon emissions from existing electric generating units (EGUs). In its review, the EPA considered a wide range of potential measures, including both improvements to the plant itself and "outside the fence" options that would reduce fossil plants' dispatch. Based on this review, EPA selected four "building blocks" as the BSER, including: (1) coal heat rate improvements; (2) re-dispatch of existing generation from coal plants to gas combined-cycle (CC) plants; (3) increased renewable and new or retained "at risk" nuclear generation; and (4) increased energy efficiency deployment.

Details on the EPA rationale for setting the building blocks and their cost and CO_2 reduction impacts are summarized in Table 1. Although these four "building blocks" are used by the EPA to set the proposed emissions standards, states will have the flexibility to use any combination of these measures or others to reduce their CO_2 emissions rates.

Table 1
Summary of EPA's Proposed Best System of Emissions Reductions

BSER Building Block	EPA Basis for BSER Determination	EPA Estimated Average Cost	% of BSER CO_2 Reductions
1. Increase efficiency of fossil fuel power plants	EPA reviewed the opportunity for coal-fired plants to improve their heat rates through best practices and equipment upgrades, identified a possible range of 4–12%, and chose 6% as a reasonable estimate. BSER assumes all coal plants increase their efficiency by 6%.	\$6–12/ton	12%
2. Switch to lower-emitting power plants	EPA determined for re-dispatching gas for coal that the average availability of gas CCs exceeds 85% and that a substantial number of CC units have operated above 70% for extended periods of time, modeled re-dispatch of gas CCs at 65–75%, and determined 70% to be technically feasible. BSER assumes all gas CCs operate up to 70% capacity factor and displace higher-emitting generation (*e.g.* , coal and gas steam units).	\$30/ton	31%
3. Build more low/zero carbon generation	EPA identified 5 nuclear units currently under construction and estimated that 5.8% of all existing nuclear capacity is "at-risk" based on EIA analysis. BSER assumes the new units and retaining 5.8% of at-risk nuclear capacity will reduce CO_2 emissions by operating at 90% capacity factor.	Under Construction: \$0/ton "At-Risk": \$12–17/ton	7%
	EPA developed targets for existing and new renewable penetration in 6 regions based on its review of current RPS mandates, and calculated regional growth factors to achieve the target in 2030. BSER assumes that 2012 renewable generation grows in each state by its regional factor through 2030 (up to a maximum renewable target) to estimate future renewable generation.	\$10–40/ton	33%
4. Use electricity more efficiently	EPA estimated EE deployment in the 12 leading states achieves annual incremental electricity savings of at least 1.5% each year. BSER assumes that all states increase their current annual savings rate by 0.2% starting in 2017 until reaching a maximum rate of 1.5%, which continues through 2030.	\$16–24/ton	18%

Sources and Notes:

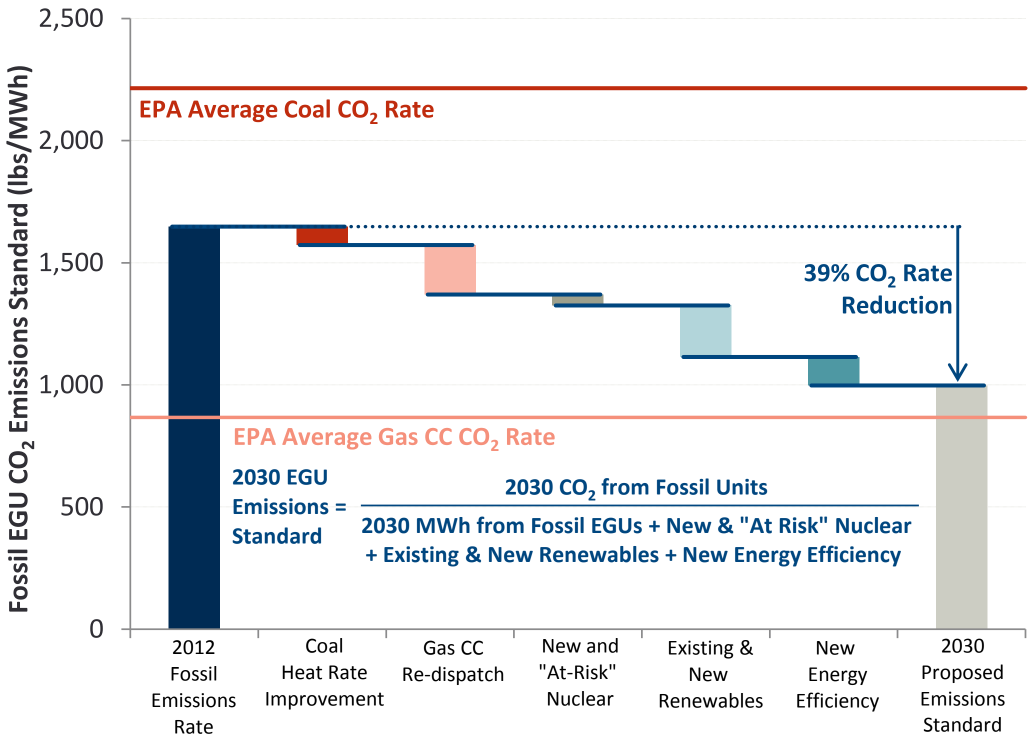
EPA, Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric Generating Units, 40 CFR Part 60, EPA-HQ-OAR-2013-0602, RIN 2060-AR33, June 2, 2014 ("Proposed Rule"). Details of Block 1 on pp. 155–171, Block 2 on pp. 171–194, Block 3 on pp. 195–218, and Block 4 on pp. 219–236.

EPA estimated average cost is calculated per metric ton of CO_2 emissions reduction.

Translating BSER into State-Specific Emissions Standards on Existing Fossil Units

The EPA uses a formulaic approach to estimate the emission reduction achievable by each state from the four building blocks. In Figure 2, we illustrate the formula for calculating the emissions standard and the relative impact of the building blocks on an aggregate national basis.[6] The starting point for the calculation is the average 2012 emissions rate of all fossil-fired EGUs, expressed as their aggregate CO_2 output divided by their aggregate generation in MWh. We then apply EPA's assumed impact of each of the building blocks sequentially to arrive at the national proposed EGU CO_2 emissions standard for 2030. The first two building blocks, improving coal plant efficiency and re-dispatching away from coal toward gas, reduce the emissions rate by reducing the quantity of CO_2 in the rate numerator.

Figure 2
Calculation of National Average Fossil EGU CO_2 Emissions Standards based on BSER



Sources and Notes:
Reflects Option 1 final rate for years 2030 from EPA Technical Support Document: Goal Computation, Appendix 1.

Then, we apply the EPA's estimated impacts from nuclear, renewables, and hydro generation capacity in the proposed BSER, which complicates the "emissions rate" because some of these resources are treated as zero-emissions supply that reduce the rate by increasing the denominator, while other zero-emitting supplies are excluded from the formula. The existing and potential new zero-emitting resources considered in the rate calculation include: (a) all nuclear currently under construction, as well as an

[6] For simplicity, in this figure and later figures, we focus on the proposed final CO_2 emissions standards to be achieved by 2030 under compliance "Option 1" after meeting the interim goal for 2020–29. The EPA also calculated alternative "Option 2" standards, which reflect less stringent emissions rate reductions that must be met earlier, with an interim rate set for 2020–2024 and a final rate for 2025 and beyond. See details on Option 1 and 2 interim and final goals posted at: http://www2.epa.gov/sites/production/files/2014-05/documents/20140602proposal-cleanpowerplan.pdf

assumed 5.8% of all existing nuclear considered "at risk" for retirement (applied uniformly to all states, rather than specifying which existing plants are deemed at risk), but excluding the remaining 94.2% of existing nuclear; (b) existing renewables (with the exception of existing hydro), new renewables, and new hydro, with the existing renewables qualified in order to give credit to early adopters of renewable generation; and (c) future energy efficiency savings, based on an analysis of the current load reduction rates achieved by the 12 leading states deploying EE programs.[7] In developing implementation plans and showing compliance, states will similarly be able to count incremental zero-emissions MWh from these categories of qualified measures as contributing to the denominator of their rates. Importantly, this accounting may result in some clean resources receiving different credit from others depending on how state plans are implemented and where their impacts are recognized in the formula.

The final 2030 aggregate nationwide average EGU CO_2 emissions standard is just under 1,000 lbs/MWh. The 2030 emissions rate represents a 39% reduction relative to the 2012 baseline rate of approximately 1,650 lbs/MWh across the industry. This 39% reduction exceeds the values shown in Figure 1, and the overall 30% reduction from 2005, since it is the reduction in a synthetic emissions *rate* formula (that includes energy savings and some zero-carbon generation in the denominator) rather than *total emissions*. The largest components of the EPA's targeted reductions are associated with substituting gas CCs for coal generation and increasing generation from renewable resources.

The Resulting Standard is Not Comparable to Typical Emissions Rate Calculations

The 2030 emissions standard formula in Figure 2 differs from typical measures of emissions rates; it represents neither the fossil fleet emissions rate (emissions divided by generation from the fossil fleet) nor the emissions rate of the entire generation fleet (emissions divided by all power generation regardless of source fuel). Instead, the EGU CO_2 emissions standard is calculated as the ratio of expected future emissions after implementing the assumed building blocks, divided by the sum of fossil, renewables, and new or "at-risk" nuclear generation (excluding existing hydro and the majority of nuclear) *plus* generation avoided through energy efficiency.

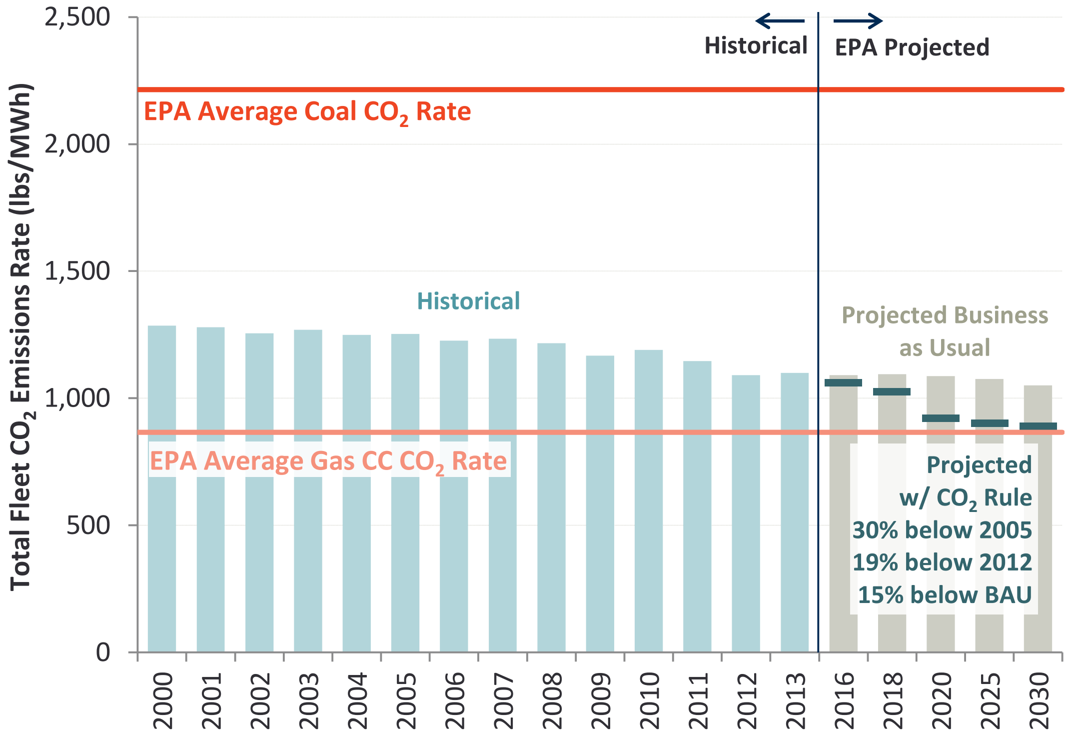
The resulting measure is relatively unintuitive, but it was constructed as a way to incorporate the benefits of activities "outside the fence" of fossil generating units, rather than just physical changes at individual fossil plants. In fact, the emissions standard will diverge greatly from the physical fossil fleet rate in most states. For example, a state could pursue energy efficiency that reduces overall emissions as well as the rate calculated for compliance purposes, but if the efficiency measures disproportionally displace gas generation relative to coal generation, this would actually *increase* the physical fossil fuel emissions rate (*i.e.*, fossil emissions divided by fossil generation). This is not necessarily a flaw, but it illustrates how intuitions about the formula may be misleading.

For comparison, we translate the EPA's EGU CO_2 emissions standards into a more typical measure of fleet-average emissions rates and total emissions of CO_2 in Figure 3. As shown, electric sector CO_2 emissions in 2012 were 2,200 million short tons, with a resulting 1,100 lbs/MWh emissions rate when

[7] See a more detailed explanation in EPA's technical support document and associated files: http://www2.epa.gov/sites/production/files/2014-05/documents/20140602tsd-goal-computation.pdf

divided across all types of generation supply, including fossil and others.[8] We compare this fleet-average rate to a similar calculation of fleet-wide emissions for future years, based on the EPA's projected total national CO_2 emissions and generation across fuel types as estimated with and without the proposed CO_2 rule. The EPA projects that the proposed rule will result in CO_2 emissions reductions of 400 million tons by 2030, reducing the fleet-average emissions rate to 890 lbs/MWh, or 19% below 2012 levels (versus a 2030 emissions standard under the EPA formula of about 1,000 lbs/MWh).[9] The resulting 2030 U.S. fleet-average CO_2 emissions rate will be about the same as the emissions rate of a typical gas CC.

Figure 3
U.S. Fleet Wide Average CO_2 Emissions Rates: Historical vs Projected



Sources and Notes:
Historical rates calculated from CO_2 emissions data from EPA CEMS database and EIA total state generation data.
Future emissions rates calculated from EPA IPM results in Base Case and Option 1: States.

The Proposed Rule Sets Diverse State-by-State CO_2 Fossil Unit Emissions Standards

Applying EPA's proposed BSER on existing fossil fuel power plants results in large differences across the states in their CO_2 emission standards and corresponding total reductions required by 2030. We demonstrate the state-by-state targets in Figure 4 by showing the states' 2012 fossil EGU rates (the aggregate height of the columns) and the impact of each building block in reducing the emissions rate to the states' 2030 standard (the lowest gray bar). The relative impact of each building block depends on

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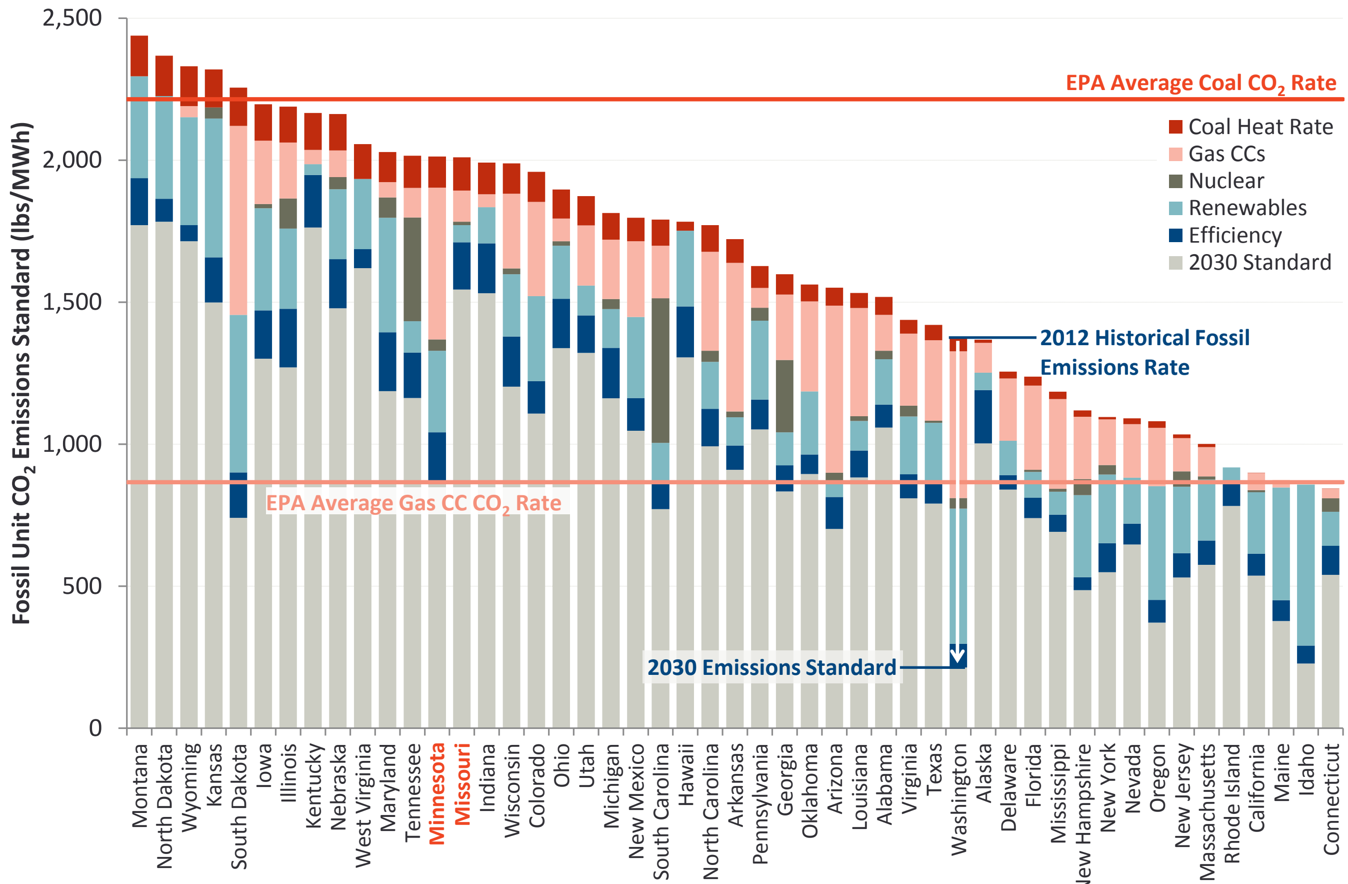
8 Source data are the EPA CEMS database for CO_2 emissions, and EIA Detailed State Data for generation, posted at http://www.eia.gov/electricity/data/state/

9 Note that total projected emissions and generation are already reduced for the impact of energy efficiency in this calculation.

the state's current generation mix, and the EPA's proposed targets for renewables and energy efficiency. For example, the impact of the assumed coal heat rate improvements is largest in states that rely heavily on coal, while the potential for coal-to-gas dispatch switching is greatest in states that have both a number of existing (or under construction) gas CC plants that could increase their capacity factors, and substantial generation from coal-fired power plants that can be displaced.

The EPA assumptions underlying the BSER building blocks result in some striking differences among the states. For example, states with similar 2012 fossil emissions rates may face very different reduction targets, as highlighted below in the difference in emissions reductions required for Minnesota compared to Missouri. The two states have similar 2012 fossil emissions rates of approximately 2,010 lbs/MWh in both cases, but Minnesota faces a substantially lower 2030 CO_2 emissions standard of 870 lbs/MWh compared to 1,540 lbs/MWh for Missouri. The discrepancy results from Minnesota's larger renewables target and much larger proportion of installed gas CC capacity that the EPA assumes can increase output to displace coal-fired generation. Note that one state, Vermont, has no standard at all, because it does not have in-state fossil generation, though it takes its power from ISO New England and could not be self-sufficient without that pool's fossil and other generation. Standards are based on the location of power sources, not their users.

Figure 4
2030 Fossil EGU CO_2 Emissions Standards by State



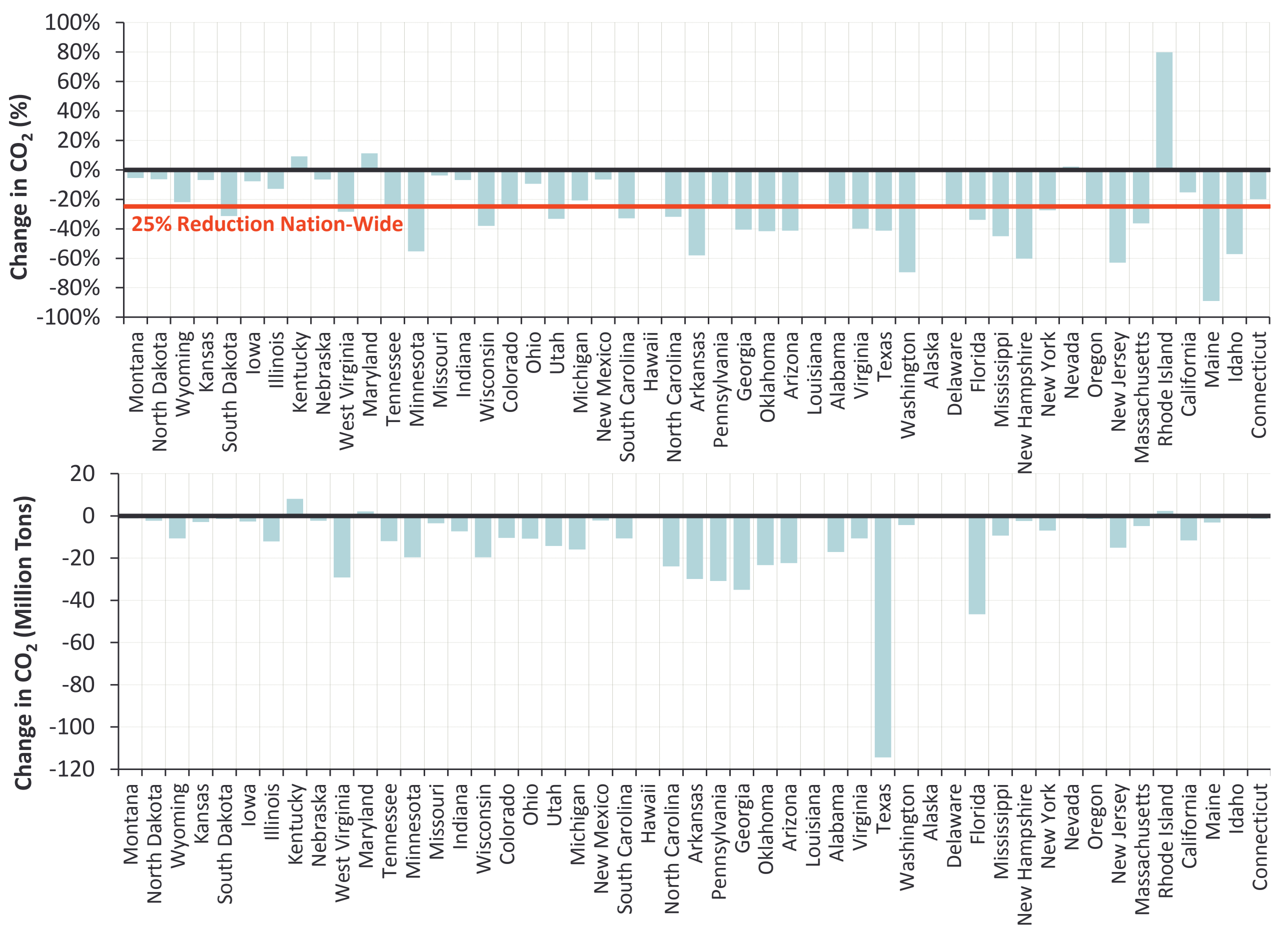
Sources and Notes:
Reflects Option 1 final rate for years 2030 and on, from EPA Technical Support Document: Goal Computation, Appendix 1.
Minnesota and Missouri highlighted in red due to the reference to them in the paragraph above.

Reviewing this rate information by itself does not provide a complete picture of the impact on each state because of the complex underlying formula. For example, some hydro-rich states such as Washington and Idaho face large reductions in the fossil emissions standard in Figure 4. However, the rate reductions appear less aggressive when recognizing that they are applied on a relatively small number of fossil units, and that a fewer number of renewable and efficiency programs can displace a larger proportion of the total fleet CO_2 emissions than in more fossil-dependent states (due to the small numerator).

We provide a more complete picture of these magnitudes in Figure 5, which shows the states' percentages (top panel) and absolute tonnage (bottom panel) of CO_2 reductions that the EPA projects its plan will achieve in 2030 relative to business-as-usual. On a percentage basis, we note substantial differences among states compared to the national average reduction of 25%. For example, the EPA projects that 15 states (mostly states that are heavily coal dependent) are projected to reduce emissions by less than 15%, while 15 other states (mostly hydro-rich states or states with substantial gas and coal capacity) will reduce emissions by more than 35%. These charts are based on EPA's no-cooperation scenario to illustrate the relative burden among states; inter-state cooperation would economically shift the geographical distribution of physical reductions.

Figure 5

EPA Estimated Changes in CO_2 Emissions (without Cooperation) Compared to Base Case in 2030



Sources and Notes:

Reflects differences in state emissions from EPA IPM results for Option 1: No Cooperation compared to Base Case.

The order of the states from Figure 4 has been maintained for comparison purposes; AK and HI excluded due to lack of IPM data.

Looking at the reductions on an absolute tonnage basis, we see the largest reductions occur in states with a large percent reduction, substantial fossil generation, and large populations. In fact, 48% of the total national reductions are achieved in only six states, with 19% of the total national reduction achieved in Texas alone (compared to its approximately 11% share of total national electric production).[10] However, the rate standard for Texas is fairly typical, as was shown above in Figure 4. According to EPA's projections, Texas would achieve this reduction primarily through energy efficiency improvements, retiring more than half of its coal fleet, and replacing retired coal units with gas CCs.[11] On the other end, there are four states projected to increase their total CO_2 emissions relative to business-as-usual, with total tons of CO_2 output increasing modestly despite a reduction in their calculated rates.

The BSER methodology proposed by the EPA involves substantial judgment and a number of technical details that leave ample opportunity for states and interested parties to argue for different approaches and different assumptions. For example, the EPA has assigned renewable energy growth rates for each state for 2020–30 based on its review of the existing Renewable Portfolio Standards (RPS) after grouping states on a regional basis. The EPA assumes that the existing RPS targets are feasible across all states in a region, without considering the states' varying definitions of "renewable" or their differences in renewable resource potential or costs.[12] Further, renewable energy resources physically located in one state but used to satisfy the RPS requirements in other states are not allocated to the buyer's state, raising questions relating to contractual rights associated with the "environmental attributes" of the renewable resources. Because the cost of complying with RPS mandates varies across states, the EPA approach of applying a single renewable assumption across each region may create asymmetric cost burdens. As another example, the EPA assumed a uniform 5.8% of nuclear generation as at risk for early retirement, even though the economic viability of nuclear plants differs greatly by plant and therefore by state.

Many more such examples exist where interested parties could reasonably argue for revised methodologies that account differently for the existing fleet of gas CCs, historically-implemented energy efficiency programs, or renewable resource base. Because these rates are calculated according to the technical capability measures that comport with the EPA's review of BSER, they do not reflect any underlying equity considerations that are of great importance to the affected states and industry participants. Depending on how the BSER methodology changes prior to the final rule, the requirements to reduce CO_2 emissions (along with the economic consequences) could shift substantially among the states.

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10 The full list of six states being 19% Texas, 8% Florida, 6% Georgia, 5% Pennsylvania, 5% Arkansas, and 5% West Virginia. Together, these states made up approximately 28% of the total national electric generation as of 2012.

11 See IPM results under Option 1: State, Supply Resource Utilization file, in Capacity Type Details output. The retirement and new generation that IPM finds to be the least cost abatement options for meeting the standard are not necessarily equivalent to the "building blocks" assumed for establishing the standard itself.

12 Instead, EPA states that using a regional approach should account for regional similarities in both cost and renewable resource potential. See Section VI.C.3 of the Proposed Rule, pp. 195 – 207.

Cost and Price Impacts Are Also Likely to Vary Substantially Across States

An immediate concern for state regulators and industry participants will be to understand the likely cost and price impacts of this rule on each state and asset type. In terms of costs, EPA projects total national compliance costs of $8.8 billion annually by 2030 in a non-cooperation scenario, as shown in Table 2. By engaging in regional cooperation that would identify the lowest cost opportunities on a broader multi-state basis, the EPA estimates that total compliance costs would be 17% lower at $7.3 billion per year. This translates to a total average CO_2 abatement cost of $15 or $13 per ton of CO_2 respectively.

Table 2
National Annual Compliance Costs and CO_2 Abatement in 2030

Scenario	Compliance Costs *(2011$ Billion)*	CO_2 Avoided *(Million tons)*	Average Cost *(2011$/ton)*
Non-Cooperation	$8.8	594	$15
Regional Cooperation	$7.3	575	$13

Sources and Notes:
Reflects cost and CO_2 differences between Base Case and Option 1.
Compliance costs und from EPA's Regulatory Impact Analysis (RIA), Table ES-4.
Avoided CO_2 from IPM for fossil units > 25 MW, EPA RIA reports slightly different numbers.

The state and regional allocation of these compliance costs will not simply be proportional to the required reductions in emissions rates or reductions in total CO_2 emissions. The ultimate cost for each state will depend on their CO_2 abatement cost curve and the mix of CO_2 reduction measures and strategies they choose to pursue. If the EPA's assumed emissions reductions based on the BSER are large but the state has few low-cost abatement opportunities, then compliance could be quite costly; if a state has more low-cost options than the EPA assumed, then the costs of compliance may be less than the required reductions imply. Further, wholesale energy price impacts from implementing these measures will be affected not by *average cost* but rather by *marginal cost* of reducing CO_2, after accounting for the details of each state's approach to implementing a trading mechanism. How these factors translate to retail rates will depend on whether the state is restructured or traditionally regulated, how the state opts to use any revenues collected from auctioning CO_2 allowances (if relevant), and which measures will be pursued through regulated planning versus market approaches.

As one initial indicator of potential price impacts, we report EPA's estimated marginal CO_2 abatement costs in 2030 for each region and state in Table 3 and Figure 6, with and without regional cooperation.[13] These EPA-estimated marginal costs can be interpreted as the carbon allowance price that would materialize if this emissions standard were accompanied with an efficient and comprehensive allowance trading program within each region. In the table we also report the approximate energy price impact that might result from such a program if gas CCs or coal were the marginal resource for energy production.

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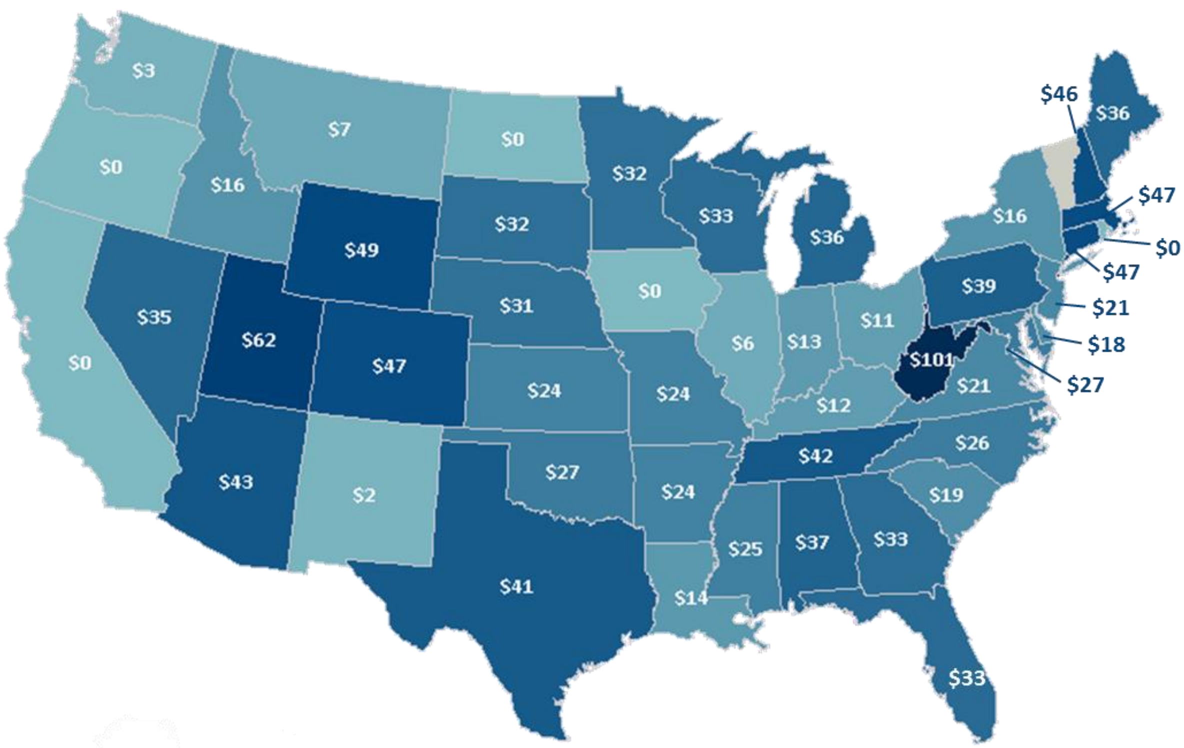
13 What we report as the marginal abatement cost is reported in raw EPA IPM outputs as the "shadow price" on the emissions rate constraint in each state or region, in units of 2011$/ton. See EPA IPM results posted at: http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html

Table 3
Marginal CO_2 Abatement Costs in 2030 and Approximate Equivalent Impact on Energy Prices

Region	Non-Cooperation Scenario			Regional Cooperation Scenario		
	Marginal CO_2 Cost *(2011\$/ton)*	Energy Price Increase if Gas CC is Marginal *(2011\$/MWh)*	Energy Price Increase if Coal is Marginal *(2011\$/MWh)*	Marginal CO_2 Cost *(2011\$/ton)*	Energy Price Increase if Gas CC is Marginal *(2011\$/MWh)*	Energy Price Increase if Coal is Marginal *(2011\$/MWh)*
MISO	\$0 - \$36	\$0 - \$16	\$0 - \$40	\$24.6	\$11	\$5
NPCC	\$0 - \$47	\$0 - \$20	\$0 - \$52	\$32.0	\$14	\$35
PJM	\$11 - \$101	\$5 - \$44	\$13 - \$112	\$31.9	\$14	\$35
SERC + FL	\$14 - \$42	\$6 - \$18	\$15 - \$46	\$31.6	\$14	\$35
SPP + ERCOT	\$24 - \$41	\$10 - \$18	\$26 - \$45	\$32.3	\$14	\$36
WECC	\$0 - \$62	\$0 - \$27	\$0 - \$69	\$32.8	\$14	\$36

Sources and Notes:
Marginal CO_2 costs are from EPA IPM results from Option 1: No Cooperation and Option 1: Regional Cooperation, reporting the shadow price on the lbs/MWh emissions rate constraint, in units of \$/ton.
Converted into approximate energy price impacts based on average gas CC and coal emissions rates of 866 lbs/MWh and 2,214 lbs/MWh respectively, implicitly assuming a uniform marginal CO_2 emissions costs, e.g. under mass-based allowance trading program.

Figure 6
State-Specific 2030 Marginal Costs without Regional Cooperation (2011\$/ton)



Sources and Notes:
Marginal CO_2 costs from EPA IPM results, Option 1: No Cooperation, reporting the shadow price on the lbs/MWh emissions rate constraint.

Figure 6 shows wide variation in marginal costs among states in the non-cooperation scenario, including between neighboring states. Such differences could create large and sometimes unintuitive incentives in the wholesale power markets, for example, to shift production from coal units in one state with more aggressive emission reduction standard to less efficient plants in another state with a less aggressive standard. The EPA assumes that with cooperation, marginal CO_2 abatement costs within each cooperating region would converge to a single value with all states having the same *marginal* incentive to reduce their carbon emissions (although total compliance costs would still differ among states). However, it is not necessarily the case that all states will have the adequate signals and incentives to cooperate. This issue depends on how the cooperative approaches can be organized and structured and how the value may be shared across utilities and consumers across multiple states. For instance, states fully within RTOs may find it easier to adopt cooperative market mechanisms than states not utilizing this wholesale structure.

States Have Wide Latitude for Developing Compliance Plans

As explained above, the state EGU CO_2 emissions standards are not requirements on individual electric generating units. Rather, they are state-wide CO_2 emissions rates that must be met in aggregate across all fossil EGUs, and each state has broad flexibility in how to meet their standard. Each state's chosen approach will depend on its regulatory structure, level of interstate power flows (sourcing of its power relative to its load), renewable resource base, and other factors affecting its options and costs of emissions reductions. In fact, most states have already implemented at least one of the building blocks the EPA has used to define the BSER.

Examples of some of the most pressing issues facing states when deciding how to comply include:

- Determining whether to adopt the EPA's proposed rates to be met by 2030 and beyond, or to choose the less stringent alternative rates that must be met sooner by 2025;
- Deciding whether to convert from a rate-based to a mass-based goal, which may be more compatible with the existing carbon emissions trading programs in California and the Regional Greenhouse Gas Initiative (RGGI) states;
- Choosing which CO_2 reduction measures to pursue to meet the target, including options beyond the four building blocks proposed, *e.g.*, coal with carbon capture and storage (CCS);
- Electing to meet these targets in-state or through multi-state arrangements, and if multi-state, which states to group with and how to make equitable, efficient, and enforceable rules for governing the multi-state system;
- Determining whether and how to compensate zero-carbon supply resources, including existing hydro and most existing nuclear units that are not explicitly included in EPA's rate-setting mechanism;[14]
- Identifying the entity responsible for complying with the state or regional emissions standards, for example, by imposing rate standards on EGUs or on load-serving entities (LSEs), or by assigning a utility or state agency the responsibility of meeting the standard through a resource portfolio approach; and

14 For example, a state may have more than 5.8% of its nuclear capacity and some of its hydro capacity at risk for retirement, but preventing these resources from retiring is not explicitly considered as part of EPA's rate-setting formula. A mass-based CO_2 trading program would create higher wholesale energy prices and revenues for zero-carbon resources, which may prevent their retirement. However, if some other programs such as zero-carbon MWh production credits were set up to exclude these existing resources, then their retirement may not be prevented even if maintaining those units were more cost-effective than other alternatives.

- Determining how to equitably allocate allowances or rates among responsible EGUs or LSEs, for example, by auctioning allowances, allocating allowances, or setting unit-specific rates that may or may not consider historical emissions rates and fuel type.

The EPA acknowledges that developing and implementing their plans may take the states several years and has provided them with a multi-year timeframe for compliance. Developing an equitable and economically efficient plan represents an enormous public policy challenge within each state, given the large number of options available, divergent views and objectives of multiple stakeholders, and the technical complexity of assessing the implications of each approach. While some states may consider the specific building blocks identified by the EPA as a starting point, other states may identify a wider portfolio of alternative approaches for carbon abatement that would be more cost-effective depending on the state's unique position. Some states may even find themselves in an advantageous position of having ample low-cost abatement opportunities that can be used to help meet other states' standards.

Many states will likely opt to develop or join an emissions trading or renewable energy trading program.[15] Consistent with the EPA's projected marginal costs, a carbon price-based regional approach can also help equalize the marginal cost of compliance and provide a transparent platform for states to collaborate. If well designed, such programs should theoretically produce the most efficient solutions, achieving the lowest cost combination of carbon-free generation, energy efficiency, and fuel efficiency at high-carbon sources throughout the trading footprint. In general, the effect would be for states with high marginal abatement costs to procure lower-cost abatement opportunities from states with lower-cost opportunities (thereby creating net societal benefits relative to a no-cooperation scenario). California and the northeastern RGGI states have already implemented such programs, making it a potentially cost and time efficient option for new states to join these existing programs rather than create their own. Since the EPA targets do not have to be met strictly on a year-by-year basis, but progressively and on average over few-year periods, it may be also be feasible to use graduated price-based approaches to incentivize carbon reductions in a manner that avoids the potential volatility of cap-and-trade mechanisms with fixed annual volume reductions.

States with regional wholesale electricity markets or large quantities of imports and exports have even greater reasons to consider joining a regional program, but must consider the nuanced incentives that may materialize between adjacent states under different approaches. For example, without a region-wide price for carbon, generators in neighboring states may face large discrepancies in production costs for similarly situated plants, and potentially uneconomic incentives for dispatch and trade. Even *with* cooperation, marginal incentives may be very different between a mass-based or rate-based approach,

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15 Note that trading programs may take one of three general forms: (1) CO_2 emissions allowance programs most consistent with the mass-based programs as in RGGI and California, which would start with a specific number of allowances (distributed to individual entities by auction or allocation) with generators needing to surrender one allowance to emit one ton of CO_2, imposing an incremental production cost based on a market price for carbon, and in turn causing an increase in energy prices that benefit all zero-carbon resource types; (2) a CO_2 abatement credits program, under which CO_2 allowances would be created by zero-emitting resources and could be purchased by fossil generators to reduce the numerator in their rates, also increasing electric prices but creating greater financial benefits for qualified zero-carbon resource types than for non-qualified types; or (3) a zero-carbon MWh credit, similar to a renewable energy credit (REC), that qualified zero-carbon resources could create and sell to fossil generators to increase the denominator of their rate (with similar potential disparities in financial impacts for qualified versus non-qualified zero carbon resource types).

e.g., if coal units in one state (with a more restrictive rate standard) would need to procure twice as many carbon allowances compared to an identical coal unit in a neighboring state (with a less restrictive rate standard). For these reasons, implementing a mass-based carbon pricing or allowance trading program that covers an entire regional transmission organization (RTO) market or region with substantial interstate flows is likely to be an efficient component of many states' plans for meeting the required reductions while avoiding undue burden on local generators that shift generation elsewhere without reducing CO_2 emissions.[16]

Many Issues Will Require Extensive Analysis

A number of complex analytical questions now face the states and affected parties. We pose here an initial set of questions that power plant owners, utilities, fuel providers, and consumers will need to explore while: (1) preparing comments to the proposed rule; (2) evaluating state alternatives for compliance; and (3) planning for future market conditions.

- What are the options and total cost of compliance for reducing CO_2 emissions in each state in a stand-alone compliance program versus in a multi-state solution?
- What would happen to energy and capacity prices, supplier net revenues, and customers' bills under alternative compliance strategies? How will the relative economics of existing and new gas, coal, nuclear, and renewable resources change?
- How will total state generation, interstate power flows, and international power flows be altered, and might some options produce unintended consequences from shifts in import and export patterns? For example, under the rate-based option without a uniform carbon price applied to all carbon emissions, might there be a perverse incentive to shift power production into states with the least restrictive emissions standards?
- What would happen to the economic viability of existing coal units, considering the cumulative impacts of other emerging EPA regulations (MATS, revived/reinforced CSAPR, 1-hr SO_2 NAAQS, 316(b) and ash rules)?
- Will excluding most existing nuclear and all existing hydropower from the standard-setting formula leave them at risk for uneconomic retirement under some state implementation approaches?
- What level of CO_2 emissions will be realized with and without the proposed EPA rule relative to historical emissions considering planned coal and nuclear retirements, additions of renewables, and other environmental regulations?
- What are the broader economic implications for the state economy, regional competitiveness, and state budget?

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16 Other options also exist for achieving efficient incentives for pricing carbon or renewables on a region-wide basis. For example, Brattle and Great River Energy recently developed a market-based regional approach for meeting the EGU CO_2 Emissions Standards through an RTO-administered carbon price. See: http://www.brattle.com/system/publications/pdfs/000/005/003/original/A_Market-based_Regional_Approach_to_Valuing_and_Reducing_GHG_Emissions_from_Power_Sector_Chang_Weiss_Yang_Apr_2014.pdf

About The Brattle Group

The Brattle Group provides consulting services and expert testimony related to economic, financial, regulatory, and strategic issues to corporations, law firms, and public agencies worldwide. We provide expert testimony on regulatory economics, environmental matters, financial risks, economic damages, antitrust, and competitive analyses. The industry practice areas in which we specialize are electric power, natural gas, petroleum, financial institutions, pharmaceuticals, healthcare, telecommunications and media, and transportation.

Our largest industry practice area is in electric power. In our electric power work, we assist regional entities, electric utilities, power producers, customers, regulators, and policy makers with planning, regulation, and litigation support. Our team offers a range of planning, analytical, operational, and financial tools for simulating, forecasting, and evaluating market structures, and the implications of proposed policies. We have the capability to model all aspects of the electric power sector including wholesale energy, ancillary service, and capacity markets, retirement and investment decisions, interstate power flows, and state-level or regional carbon markets. We have a depth of experience in restructured and traditionally-regulated wholesale power markets across all regions of the U.S. and Canada, as well as a number of other international markets.

The Brattle Group originated in 1990 with five principals dedicated to integrity and excellence in economic and financial consulting. In 1995, Brattle combined with Incentives Research, Incorporated to strengthen its expertise in energy matters and opened its first office in Cambridge. Since then we have grown to a staff of more than 200 and have opened offices in London, Rome, Madrid, Washington, DC, San Francisco, and New York City.