Issue Brief

The Clean Power Plan

Focus on Implementation and Compliance

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The Clean Power Plan presents the states with a complex set of choices to reduce CO_2 emissions from their electricity sectors. States must decide what form of target to adopt, the role of market-based emission credits or allowances, and the desired range of interstate trading opportunities. States making these choices will try to satisfy multiple objectives and respond to a broad range of stakeholder opinion on the best path forward. This paper introduces some of the tradeoffs and analyses that states and stakeholders should consider in selecting an implementation and compliance system to attain the ambitious goals of the Clean Power Plan.

In August 2015, the Environmental Protection Agency (EPA) finalized its carbon dioxide (CO_2) emission standards for existing power plants under Section 111(d) of the Clean Air Act, a rule commonly known as the Clean Power Plan (CPP). At the same time, the EPA provided a blueprint for moving forward by defining tradable compliance instruments, delineating the scope of intrastate and interstate trading, and proposing sets of state and federal implementation mechanisms intended to enable compliance.

In the final CPP, the EPA pushed back by two years the deadline for states to finalize implementation plans (now 2018) and the initial compliance period (now 2022) in response to comments expressing concerns about the Draft Plan's administrative feasibility, near-term costs, and potential reliability impacts. While the derivation of the emission standards and the distribution of emission reductions among the states changed considerably between the proposed and final rule, the resulting phase-in of the emission guidelines for most states (and existing generating units) represents a more gradual transition to lower CO_2 emissions than the proposed regulation.

Starting with a single set of CO_2 emission rate standards that will apply to fossil steam and natural gas combined cycle (NGCC) units, the EPA derived multiple emission rate and emission mass standards that states might adopt to demonstrate compliance, under a presumption that the two types of goals are equivalent even if compliance mechanisms differ. The EPA also clarified that while states choose the compliance approach, individual existing fossil fuel-fired units will be responsible for complying with the CPP—likely via a much broader role granted to trading mechanisms of either emission allowances or emission rate credits (ERCs), depending on how states elect to implement the CPP. By issuing proposed model trading rules for states to use in developing implementation plans and proposed federal plans that rely on tradable instruments, the EPA has expressed a clear preference for market mechanisms to incentivize generation from lower-emitting resources over the next decade and a half.

This issue brief provides an overview of the CPP and discusses three key observations for stakeholders in the regulatory process:

- First, **while the EPA has given states a broad slate of implementation options from which to choose, the different options are not equivalent in many important dimensions.** State-level outcomes, such as cost, cost incidence, resulting CO_2 mitigation and wholesale electricity prices, coal unit retirements, new in-state renewables development, and emission reductions can vary across the different implementation pathways. Therefore, states attempting to achieve particular policy objectives may favor some approaches over others. For example:
  - States with significant renewable potential and a strong preference to retain coal plants may benefit from a rate-based plan;
  - States expecting low load growth may find mass-based approaches less costly;
  - States that expect to attain (and beat) emission rate standards with in-state renewables may prefer a state average rate approach, which would limit the ability of ERC producers from selling these credits out of state to offset higher emissions elsewhere; and
  - States worried about retaining existing nuclear plants may prefer higher wholesale prices and allowance allocations under a mass-based approach.
- Second, **the outcomes expected under each state's implementation decision will depend, in part, on the decisions of other states** (*i.e.*, they are co-determined). This interdependence substantially complicates the decision process, and implies that states will benefit from information about other states' deliberations and analyses of their expected choices among compliance plan options. For this reason, states will likely enjoy advantages from coordinating implementation decisions with each other in order to achieve local policy objectives in both the near and long term.
- Finally, **the Regulatory Impact Analysis (RIA) that the EPA conducted is unlikely to provide useful information for states deciding between alternative implementation approaches**. This means that states will have to perform their own analyses, with the input of their important stakeholders, to make implementation decisions that reflect their policy objectives.

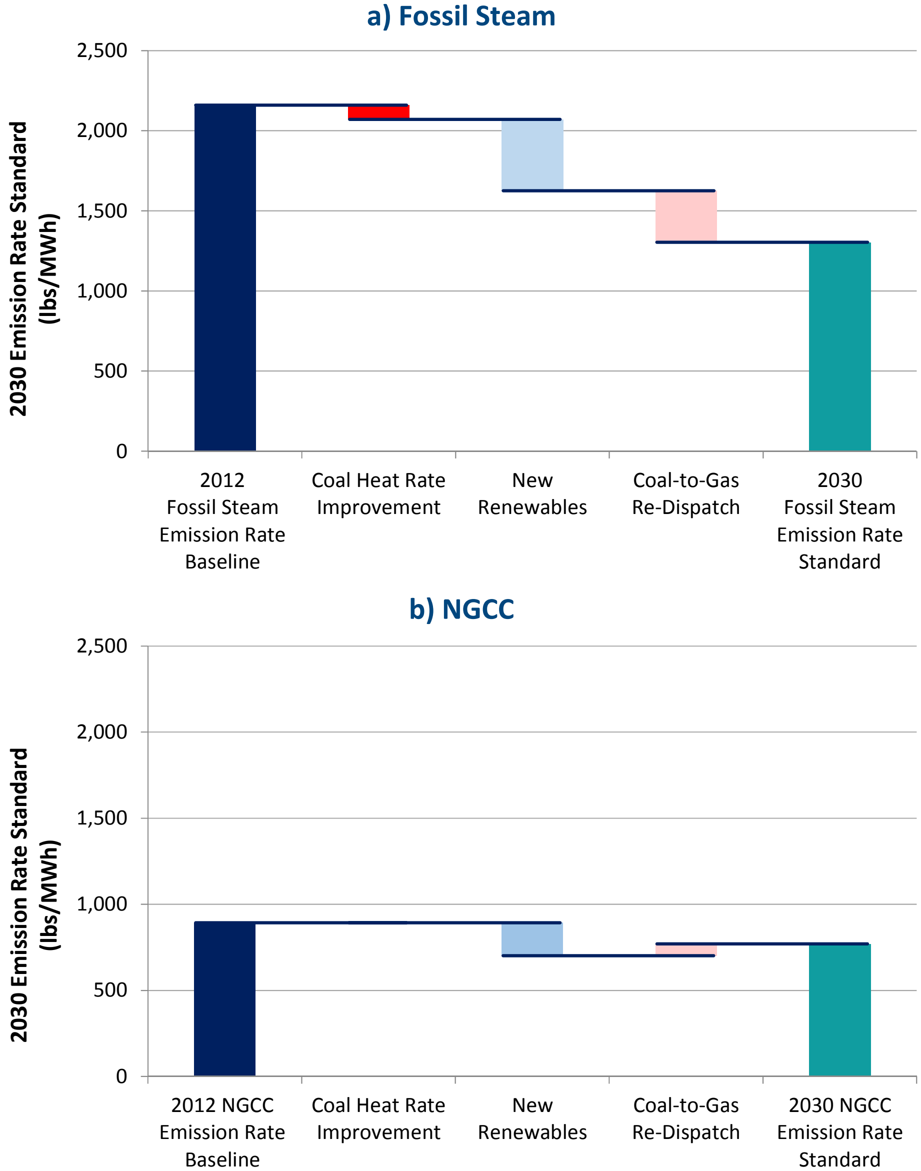
Brief Introduction to the Final Rule

Between the proposed and final CPP, the EPA significantly changed its approach for setting CO_2 emission standards for fossil electric generating units (EGUs). Most notably, the EPA excluded some zero-emission resources from the Best System of Emission Reduction (BSER) building blocks[1] and moved from state-specific emission rate targets to nationwide "subcategory" performance standards that form the basis for all rate- and mass-based implementation options that states may adopt. The two subcategory performance standards apply to: (1) existing fossil steam units (*i.e.*, coal-fired units and oil/gas steam units), and (2) NGCC units. A third category of fossil electric generation—existing simple cycle gas- or

[1] In the final rule, the EPA set the BSER targets based on coal-fired EGU heat rate improvements, coal-to-gas re-dispatch, and increased generation from new renewable resources, but removed energy efficiency, generation from existing renewables, or generation from at-risk and new nuclear units as BSER building blocks. However, the EPA sharply increased its estimate of new renewable energy potential compared with the proposed rule.

oil-fired combustion turbines (CTs)—neither factors into the standard-setting calculations nor faces compliance obligations under the final CPP.

Figure 1: 2030 Subcategory-Specific Emission Rate Standards



Source: Brattle analysis of EPA, CO2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule, Docket ID No. EPA-HQ-OAR-2013-0602, August 2015 ("CPP Goal Computation TSD").

Notes: In setting the BSER, renewables are allocated to steam and NGCCs based on their relative share of generation in the 2012 adjusted baseline. In the NGCC target formula, NGCC emissions and generation increased due to the coal-to-gas redispatch. As NGCCs have a higher emission rate than renewables, this increases the NGCC rate.

The EPA derives these uniform national standards by applying the updated three BSER building blocks at the wholesale market interconnection level. In each year, the interconnection with the highest achievable emission rate in each subcategory sets the performance standard for the entire country. Figure 1 shows the derivation of the performance standards for 2030, which was based on the results from the Eastern Interconnection.

The CPP allows states to select from three general implementation approaches for affected EGUs: mass, rate, and state measures. The goals of each of these implementation approaches are derived from the subcategory specific emission rates depicted in Figure 1. Under emission rate implementation plans, each affected EGU must comply through a combination of emission-rate improvement and the acquisition of ERCs. Likewise, under a mass plan, each affected EGU must comply by procuring a number of CO_2 allowances equal to its volume of CO_2 emissions. Finally, under a state measures plan, a state may select a portfolio of approaches, including multi-sector cap and trade (beyond just electric generation), if the resultant emissions from affected EGUs remain below the state's mass goal. A summary of the compliance approaches is shown in Table 1 and each will be discussed in greater detail in the following sections.

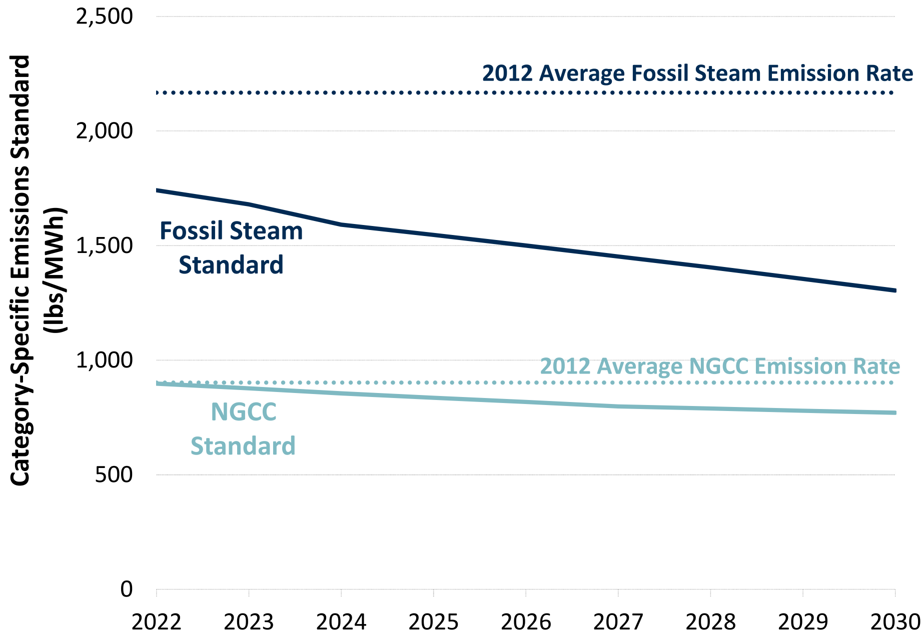
Table 1: Implementation Approaches

	Emission Standards		State Measures
Goal Type	**Rate**	**Mass**	**Mass**
Trading Instrument	Emission Rate Credit (ERC)	Allowance	Varies
Trading Instrument Definition	One megawatt-hour (MWh) of zero CO_2 Generation	One short ton CO_2	Varies
Covered Generators	Existing EGUs	Existing EGUs or Existing + New EGUs	Emission reductions must be met by covered EGUs; however, additional parties may be required to comply with state measures.
Compliance Formula	$Rate\ Standard = \frac{EGU\ Emissions}{EGU\ Generation + ERCs}$	$CO_2\ Allowances = CO_2\ Emitted$	State plan dependent.

Rate-Based Performance Standards

Under the subcategory-specific rate standards, affected EGUs demonstrate compliance by meeting the applicable technology specific targets (*i.e.*, fossil steam EGUs must achieve an emission rate equal to or less than the fossil steam rate, while NGCC EGUs must achieve an emission rate equal to or less than the NGCC rate). For most units, especially coal-fired steam units, meeting these standards requires obtaining credit for activities "outside the fence" of the unit itself—*i.e.*, actions that stimulate the operation of cleaner generation sources elsewhere or reduce demand for electricity. Figure 2 shows the subcategory-specific emission rate targets over time.

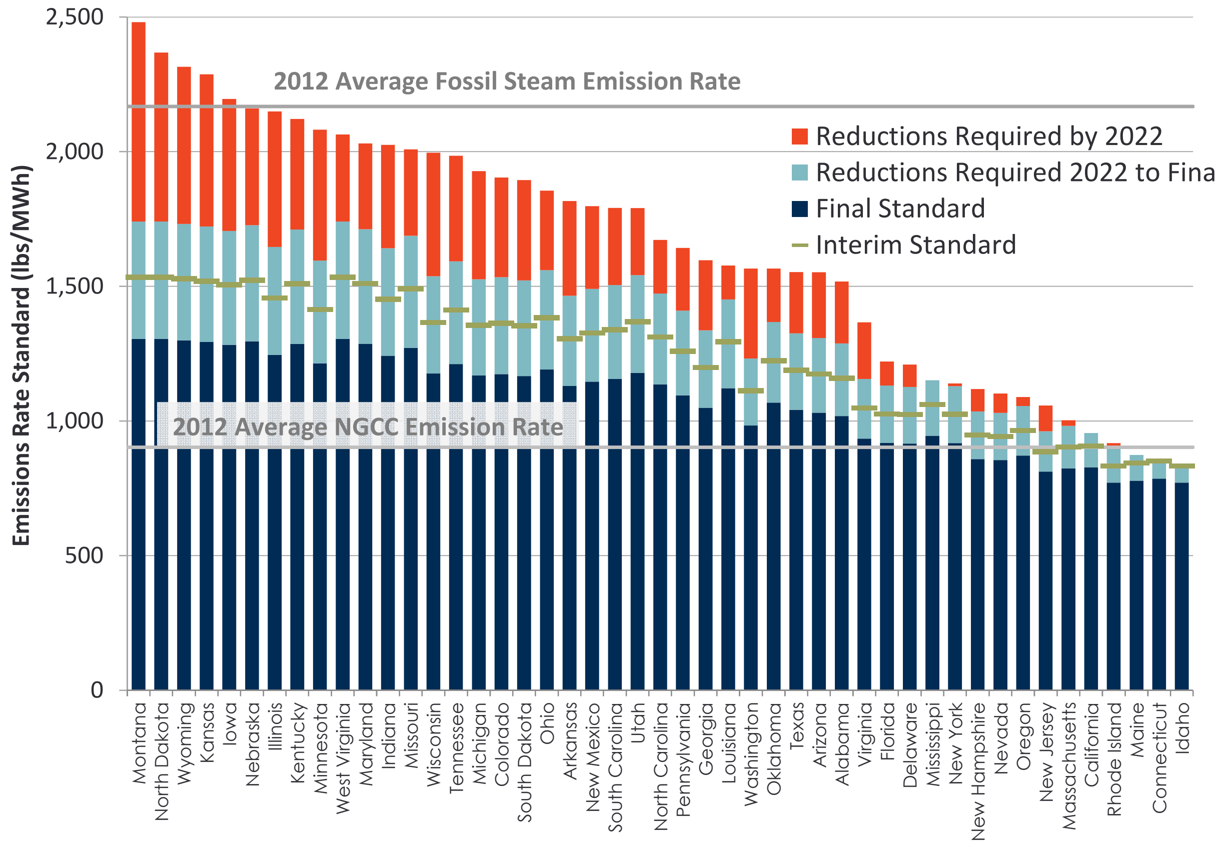
Figure 2: Subcategory-Specific Rate-Based Emission Standards



Source: EPA, CPP Goal Computation TSD, August 2015.

Alternatively, a state can set a single, statewide rate-based emission standard for all EGUs based on the average of the subcategory-specific standards (weighted by the state's 2012 adjusted baseline generation mix). The state average rate-based standards are shown in Figure 3. The red bars represent the reduction in emission rates required between 2012 and 2022, which reflect coal heat rate improvements and a portion of the emission reductions achievable through the remaining two BSER building blocks. The light blue portion of the bars represents additional reductions necessary from 2022 rates to meet the final 2030 standard. States with a larger share of fossil steam units in their generation mix tend to be towards the left (and face commensurately deeper and earlier rate cuts to attain the goal), while NGCC-heavy states are on the right.

Figure 3: Statewide Average Rate-Based Emission Standards



Source: EPA, CPP Goal Computation TSD, August 2015.

Under both the subcategory performance standards and the state average rate-based standards, EGUs can lower their emission rates by obtaining ERCs, which are equivalent to one megawatt-hour (MWh) of zero-carbon generation. For compliance purposes, EGUs can include ERCs in the denominator of their individual unit emission rate calculation (*i.e.*, they are additional MWhs that do not contribute to the mass emission numerator). ERCs can be generated by a number of sources, as shown in Table 2. States that adopt the national subcategory performance standards are deemed "trade-ready," and owners of ERCs in such states may trade ERCs with entities in other states that adopt subcategory performance standards. In contrast, the EPA would limit interstate ERC trading among states that adopt the state average rate approach to those states that agree to attain a common standard that reflects a composite of the individual state average standards.[2]

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2 States can also design custom rates for individual sources, subject to a determination that the overall effect would be to achieve the CO_2 emission performance rate or state rate-based CO_2 goal. The EPA would not deem such a plan "trade-ready" and therefore EGUs subject to such an implementation plan would have to procure ERCs from within the state.

Table 2: Potential Sources of ERCs

	Rate Plan Type	
	Subcategory Specific	**State-Average**
Trading Partners	Other Subcategory Specific Plans	Within the State or States Adopting Joint Goal
ERC Type		
"Fossil" ERC	Created by in-state affected NGCC & steam generators	Created by in-state affected NGCC & steam generators
"Non-Fossil" ERC	Created by new in-state renewables (RE), energy efficiency (EE), and nuclear	Created by new in-state EE, RE, nuclear
"RE " ERC	Created by new out-of-state RE located internationally or in a mass-based plan state; requires PPA or other delivery contract to a rate state	Created by new out-of-state RE located internationally or in a mass-based plan state; requires PPA or other delivery contract to a rate state
Gas-Shift ERC	Created by in-state affected NGCC generators; usable only by steam generators	n/a

Mass-Based Performance Standards

States can also choose to pursue a statewide mass standard, *i.e.*, a cap on tons of CO_2 emitted per year from affected sources. The EPA derives statewide annual emission tonnage caps by multiplying 2012 adjusted[3] baseline generation (MWh) by the state average rate target (lbs/MWh), further multiplied by a nationally uniform upward adjustment factor divided by 2,000 lbs/ton. This adjustment factor varies from 6.3% to 10.9% depending on the year. [4]

Table 3: Rate to Mass Conversion Adjustment Factors

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate to Mass Factor	1.065	1.063	1.064	1.070	1.076	1.077	1.089	1.100	1.109
Percent Above Gen x Standard	6.5%	6.3%	6.4%	7.0%	7.6%	7.7%	8.9%	10.0%	10.9%

Source: Brattle analysis of EPA, CPP Goal Computation TSD, August 2015.

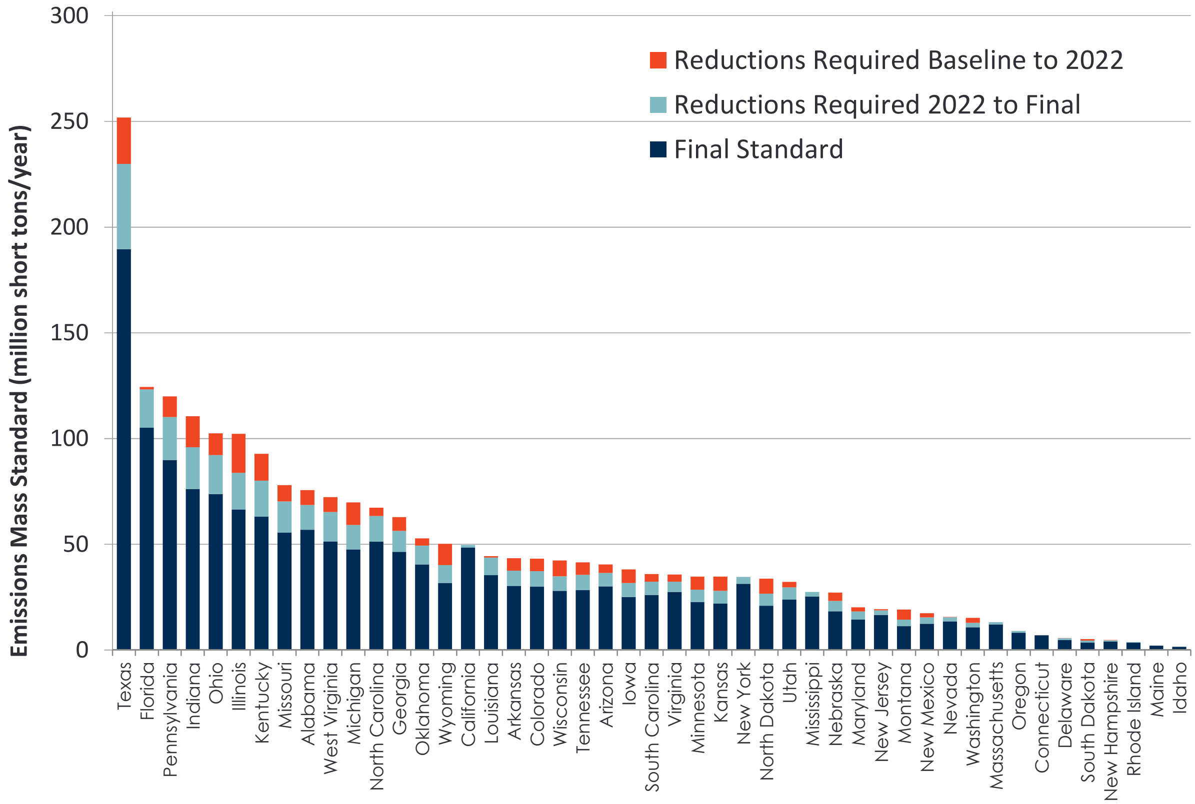
Under a mass-based plan, existing EGUs must procure an allowance for each ton of CO_2 emitted to comply with the rule, and states are authorized to distribute or auction the allowances to parties the state choses. However, if a state confines the emission cap to existing units only, they must demonstrate that the allocation method reduces or eliminates "leakage", which the EPA defines as the incentive to operate (and emit from) newly constructed or unaffected fossil units in lieu of operating existing units

[3] The EPA adjusted unit-level and state-level fossil generation in its 2012 data to better reflect typical operations of units by adjusting for hydro conditions, outages for units representing large portion of state generation portfolio, and expected new fossil steam and NGCC generation. See Technical Support Document (TSD), "CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule."

[4] This adjustment factor is based on an analysis of additional potential renewable energy.

that are subject to a cap on existing sources only. The mass-based standards for existing EGUs are shown in Figure 4.

Figure 4: Mass-Based Emission Standards for Existing EGUs

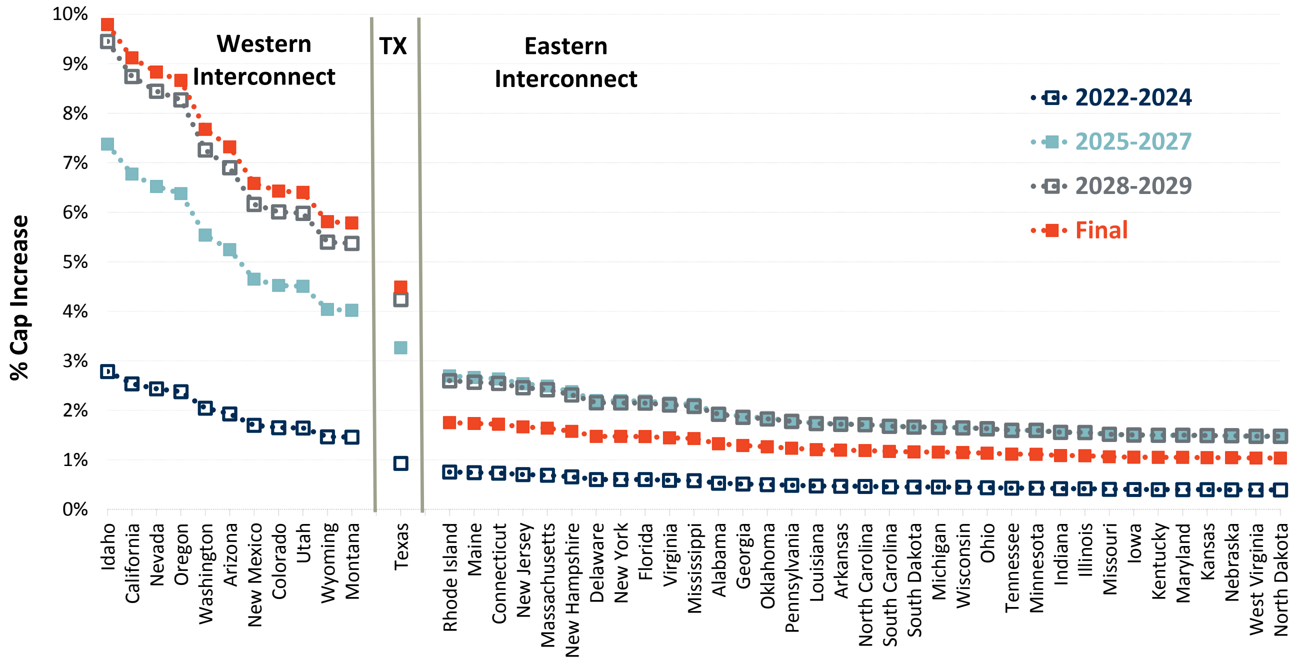


Source: EPA, CPP Goal Computation TSD, August 2015.

States adopting a mass-based plan also have the option to cover CO_2 emissions from both existing <u>and</u> new EGUs by either accepting the EPA's calculation of the "new source complement" or providing their own estimate subject to the EPA's approval.[5] The EPA's calculation is based on projected load growth and includes downward adjustments to account for projected generation from new renewables and existing (and under construction) affected EGUs. The new source complements increase the annual state emission caps and vary by year and state, as shown in Figure 5. For states primarily in the Western Interconnect, the new source complements range from 6% to 10% and increase over time. In Texas, the 2030 new source complement increases the emission cap by 4.5%. In the Eastern Interconnect, typical new source complements in 2030 add between 1% and 2% of the state-level mass target, but actually are higher in 2025-2027 than in 2030 (*i.e.*, they decline during the final compliance period). In exchange for adopting the new source complement and covering existing and new affected EGUs, a state would no longer have to demonstrate that its implementation plan reduces or eliminates leakage, as the new source coverage would obviate the concern.

5 "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units", VII.J(b)

Figure 5: New Source Complement Percentage Increase in Cap Compared to Existing Unit Cap Only



Source: Brattle analysis of EPA, CPP Goal Computation TSD, August 2015.

Finally, states wishing to use existing mass-based state programs to meet the CPP goals can adopt a state measures approach provided it is at least as stringent as the EPA's mass-based standards for covered EGUs and includes a federally enforceable contingent backstop. For example, California is considering how it can use its existing economy-wide cap and trade program under AB 32 to meet the CPP requirements.

State Implementation Choices Will Affect a Range of Outcomes

According to the EPA, the statewide rate-based and mass-based emission standards are equivalent to the subcategory performance standards.[6] However, depending on an individual state's circumstances, total costs of compliance and the total CO_2 emissions allowed under the rule will vary by implementation option. Moreover, rate-based standards and mass-based standards have different impacts on wholesale energy prices that may affect a state's level of energy exports and imports in the near term and both retail prices and returns on clean energy investment over the long term. Despite the EPA's effort to make the approaches equivalent, important differences emerge that could be very important to states' deliberations.

[6] "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units", XII.A In the final emission guidelines, the EPA has translated the source category-specific CO2 emission performance rates into equivalent state-level rate-based and mass-based CO2 goals in order to maximize the range of choices that states will have in developing their plans.

In addition to variation in the effects of alternative implementation approaches, states may apply different criteria to guide their decisions. Some states may consider minimizing near-term EGU compliance cost as a paramount objective, while others may target alternative objectives, such as total nationwide CO_2 emissions; support for specific investments within the state such as EE and RE; retaining coal or nuclear generation capacity; or limiting changes in wholesale and retail prices over longer timeframes. Even states applying identical decision criteria to similar circumstances may view longer-term risks quite differently and elect different implementation approaches. We address several issues concerning state implementation choices below.

Are Mass-Based Standards and Rate-Based Standards Equally Stringent?

When setting the mass-based standards for existing EGUs, the EPA makes an upward adjustment to account for "excess building block 3 potential" that varies between 6% and 10%.[7] Some observers have concluded that this adjustment results in a mass-based standard that is less stringent than the rate-based standards. While the mass-based standard may be less stringent for some states, this adjustment does not lead to the *a priori* conclusion that the mass-based standard will be less stringent for all states. For example, the EPA's own modeling suggests that, in most years, overall CO_2 emissions will be higher under rate-based standards than under mass-based standards.

For any given state, multiple factors affect whether rate-based compliance requires greater CO_2 emission reductions than mass-based compliance. In states that expect high load growth, but whose affected EGUs had relatively low capacity factors in 2012, rate-based compliance allows EGUs the ability to increase their emissions from 2012 levels while remaining in compliance by acquiring additional ERCs to offset the increased emissions. By contrast, mass-based compliance may be less stringent in low load growth states where emissions are expected to fall with the retirement of uneconomic affected EGUs. The availability and cost of new renewables and energy efficiency will also affect the relative compliance costs. Falling costs for generation from wind and solar may have a larger impact on compliance costs under rate-based approaches than under mass-based approaches. Likewise, renewable energy or energy efficiency investments that occur between 2013 and 2021 and produce valid ERCs in 2022 and beyond may comprise a valuable initial compliance reserve in some states that adopt a rate-based approach.

Different compliance opportunities can arise as a function of how the state's affected fossil fleet operated in 2012. For example, the average capacity factors of fossil steam and combined cycle plants, as well as the overall capacity factors of the combined fleet, define the amount of "headroom" for affected EGU potential generation growth going forward. To the extent that the 2012 capacity factors of fossil steam, NGCC, or both types of units are less than their practical maximum outputs, there is additional generation headroom relative to historic levels. A state with substantial headroom in its NGCC and fossil steam fleet would find it more difficult under mass-based caps to meet load growth by increasing the use of its existing units in the same proportion than adopting a rate-based plan.

Figure 6 shows the wide variety in the average capacity factor of fossil steam and NGCC units across the states. For each state (represented by a dot), the position of the dot reflects the 2012 capacity factor of

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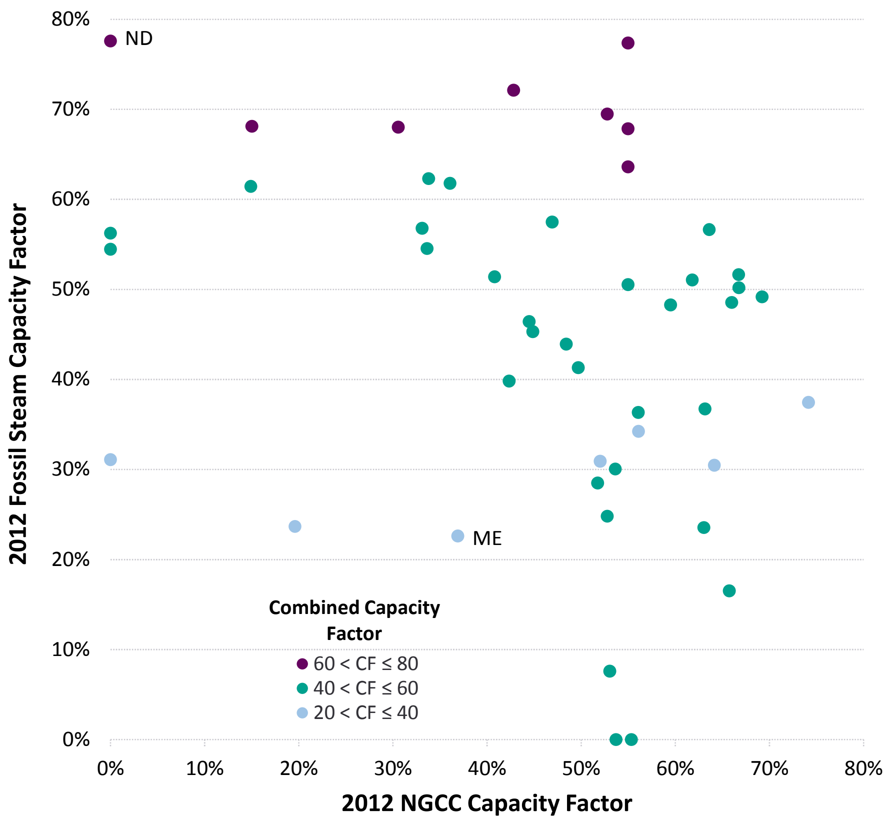
7 EPA, CPP Goal Computation TSD, August 2015, p. 21.

NGCC plants (measured on the horizontal x-axis) and fossil steam (measured on the vertical y-axis), and the color indicates the composite capacity factor of that state's fossil fleet (with light blue indicating a combined fossil capacity factor below 40%, green indicating a combined fossil capacity factor between 40% and 60% in 2012, and purple indicating a combined fossil capacity factor over 60%).

Figure 6: 2012 Average Capacity Factors for NGCC vs. Fossil Steam EGUs by State



Source: Brattle analysis of EPA, CPP Goal Computation TSD, August 2015.

Notes:

1. Figure reflects capacity factors for covered EGUs present in the 2012 EPA Adjusted Baseline
2. Figure does not include capacity from standby, retired, or under construction plants

This figure shows the substantial variation in the 2012 observations. For example, affected EGUs in North Dakota (all coal units), shown in the upper left-hand section of the figure, operated at a 78% overall fossil steam capacity factor. Affected EGUs in Maine, shown in the middle of the figure, operated at 23% for fossil steam but 37% for its NGCC capacity factors. All else held equal, states that experienced high overall capacity utilization (including North Dakota, Wyoming, and Colorado) may be more inclined to accept a mass limit, given that such a limit would not materially constrain existing generation from its previously high levels. Conversely, a state with low 2012 capacity factors (including Maine, Maryland, and Washington) might prefer the rate-based standards as it will allow them to utilize the "headroom" in the existing fleet. Many other factors could influence the determination of which approach is more or less stringent. These include the relative capacity factors of NGCC and fossil steam, amount of capacity of each type of units, the percent reduction in emission rate required, and the potential for renewable energy and/or energy efficiency to provide ERCs.[8]

ARE SUBCATEGORY RATE STANDARDS EQUIVALENT TO STATE AVERAGE RATE STANDARDS?

Since the EPA calculates the *state average* rate-based standards using a simple 2012 generation-weighted average of the *subcategory* rate-based standards, one might conclude that they are fundamentally equivalent. However, the power system has evolved since 2012 and will continue to evolve through retirements, new units, and shifting load patterns. Load may resume growth or may stagnate regionally or nationally. National policies and state policies will influence the mix of new generation plants. As this divergence from the 2012 baseline continues, the equivalence will increasingly break down.

For example, a state that expects significant retirements in its existing fossil steam will generally find the subcategory rate-based standards more stringent than the state average rate-based standards. Washington provides an example of this phenomenon. The Transalta Centralia Generating Station, which consists of two identical boilers, constitutes the entirety of the state's fossil steam fleet covered by the rule. Under current law, the first units will retire by the end of 2020 and the second unit will retire by the end of 2025. If the retirement of the second unit were advanced to the end of 2021, the only affected EGUs in the state would be NGCCs. Both Washington's interim statewide rate standard of 1,111lbs/MWh and its final compliance standard of 983lbs/MWh are higher than the comparable NGCC subcategory performance standards of 832lbs/MWh and 771lbs/MWh. Thus, if all the steam capacity at Transalta Centralia Generating Station retires prior to 2022, a statewide rate-based approach will be significantly less stringent for Washington than subcategory performance standards.

However, the subcategory performance standards are not always more stringent than the statewide rate-based goals, at least in terms of ERC requirements. For example, maintaining emissions and generation at the level of the 2012 adjusted baseline will generally require fewer ERCs from zero-emission sources under the subcategory performance standards than under the statewide rate-based standards. In Arizona, the 2012 adjusted baseline includes 25 TWh of fossil steam generation with 28 million tons of CO_2 emissions and 27 TWh of NGCC generation with 12 million tons of emissions. To maintain that level of generation and emissions under the statewide rate-based standard of 1,031lbs/MWh, affected EGUs would need to obtain 26 TWh of ERCs from zero-emission sources in 2030. However, under the subcategory performance standards, affected EGUs only would need to obtain 21 TWh of ERCs from zero-emission sources in 2030, a reduction of 20%.[9]

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8 This especially true for states planning on expanding or continuing EE programs prior to 2022, as near-term investments that continue to reduce demand during the compliance period 2022 and beyond could generate significant ERCs (which we refer to as latent or embedded ERCs) for compliance. The EPA has identified the important role that the measuring and verification processes will play in determining the amount of ERCs that should be generated from EE investments (potentially from up to a decade prior to 2022) and proposed guidelines for doing so that reflect best practices from states with existing large EE programs. See: http://www.epa.gov/sites/production/files/2015-08/documents/cpp_emv_guidance_for_demand-side_ee_-_080315.pdf.

9 Gas shift ERCs account for approximately 2 TWh of the reduced need for ERCs from zero-emission sources.

How Much Do Allowance Allocations Matter in Mass-Based Plans?

If a state elects to implement a mass-based approach, it will allocate allowances either through direct distributions or auctions and then require fossil EGUs to procure sufficient allowances to cover their future emissions. Identifying the approach to allocating allowances is likely to be politically contentious, as the state agency or legislature will be in the position to make clear choices about who receives revenues from sales of allowances in the new market. States will consider a wide range of allocation approaches that target specific technologies, generation facilities, or customers and identify an approach that achieves their particular political objectives. For example, California allocates allowances for the purpose of protecting residential ratepayers and reducing the potential for emission leakage that could arise as out-of-state energy intensive industries expand output in response to a contraction in the output from California plants.. Allowances in the Regional Greenhouse Gas Initiative (RGGI) are auctioned by the states and used to fund EE and renewable programs to help defray customer costs.[10]

The allocation approach will not have an effect on emission reductions (as they are dictated by the cap) and will have limited impact on near-term allowance prices (which equilibrate at the marginal abatement cost of the last ton reduced). However, the approach can have a substantial impact on the costs borne and revenues received by different stakeholders. For example, the impact of allocating allowances only to affected EGUs either based on 2012 generation output (as proposed under the federal plan) versus 2012 CO_2 emissions can be quite significant. Figure 7 shows the percentage of allowances that could be allocated to either fossil steam EGUs or combined cycle EGUs depending on the allocation method chosen (excluding those that might be set-aside for other purposes). These percentages reflect the proportion of overall allowance value that would shift from NGCC owners to fossil steam owners if the allocation system changed from a MWh output basis to a CO_2 emission-based allocation. In roughly half of the states where such a change would alter the distribution of allowances, more than 10% of the overall allowance value would be at stake. For example at an allowance price of $10/ton, the transfer in value in 2022 between fossil steam and NGCC plants in Texas would be roughly $100 million and in Pennsylvania would be $45 million depending on the allocation approach chosen.[11]

Figure 7 illustrates the potential difference between allowance allocations assuming a static composition of the generation fleet. However, many coal retirements have already occurred since 2012 and more are expected, resulting in further differences between allocation methods due to the renewable set-aside provisions intended to limit "leakage" in the proposed model trading rule. Under the proposed model trading rule, 5% of allowances from the general pool are set aside to fund renewables (known as the "renewable set aside"), which EPA contends will reduce leakage from affected sources to new sources not covered by the CPP. These proposed rules would reallocate allowances from retiring fossil steam units into the in-state renewable set-aside, meaning that states that experience significant coal retirements would allocate a substantial number of allowances to renewables and that reallocation

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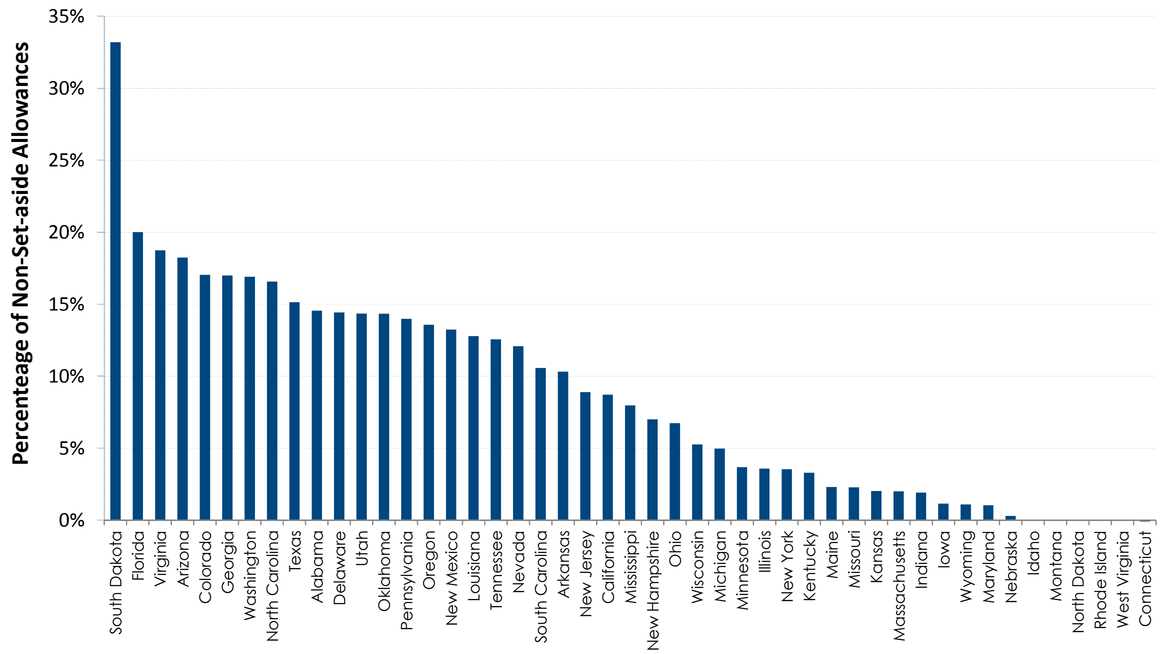
[10] See https://www.rggi.org/rggi_benefits

[11] We calculate the wealth transfer between the plant types assuming all existing units affected by the CPP continue operation through 2022. Allowances which would be allocated to a retired generator are added to the renewable set-aside. As some plants have retired since 2012, and others will likely retire by 2022, a portion of the transfer would be between retired plants and renewable generators.

would affect the relative shares between the remaining fossil steam and NGCC.[12] To the extent that leakage to new sources is prevented, allowance prices will increase.

Figure 7: Percentage of Allowances Shifted between Fossil Steam and Combined Cycle due to Allocation Approach (2012 Generation Basis vs. 2012 Emission Basis)



Source: Brattle Analysis of EPA, Allowance Allocation Proposed Rule Technical Support Document, Docket EPA-HQ-OAR-2015-0199, August 2015.

Notes:

1. Figure reflects average annual allowances for first interim compliance period (2022-2024)
2. Figure reflects allocation of allowances not included in the renewable energy and CEIP set-asides

Over the long term, state decisions on allocation can influence resource decisions, and thus impact allowance prices and overall compliance costs. For example, allocating allowances to new EE programs (utilities or ratepayers) will result in lower load and possibly lower allowance prices. On the other hand, allocating allowances to fossil plants to avoid retirements may limit low cost compliance options in the interest of local economic development and increase allowance prices. As states make such decisions based on their own circumstances and objectives, they can affect allowance prices and the economics of abatement in other states that participate in mass-based allowance trading.

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12 The EPA also proposed an "Alternative Compliance Pathway" for units that retire before January 1, 2030. Under the proposal, eligible generating units that select the Alternative Compliance Pathway will receive a mass-based emission limit to be used before January 1, 2030. All generators selecting the proposed Alternative Compliance Pathway will receive a unit-specific mass-based emission budget, regardless of State Implementation Plan type. In states selecting a mass-based plan, the emission limit assigned to units selecting the Alternative Compliance Pathway will be subtracted from state's mass-cap.

How Will Complementary Policy Measures Affect Implementation Choices and Outcomes?

Regardless of the state plan chosen, states are likely to also pursue related and complementary energy and environmental policies that could have significant impacts on the value and quantity of tradable compliance instruments (*i.e.*, allowances or ERCs). For example, most states already have renewable portfolio standards (RPS), energy efficiency programs, or net metering requirements and may expand those efforts to achieve lower cost compliance or incentivize local resources. Complementary policy measures that mandate additional low-carbon technologies will tend to reduce the value of allowances and ERCs, while measures designed to defer fossil steam retirements to mitigate stranded costs or limit the impacts on economic development will tend to increase their prices. Due to the uncertainty in complementary policies and the number of states that choose each approach (as we discuss in the next section), states that consider participating in compliance instrument trading with other states (either as a net seller or buyer) will need to evaluate a wide range of future allowance or ERC prices to understand how compliance costs and in-state resources are impacted at different price points.

Following the selection of the compliance approach, state-by-state decisions to pursue complementary measure such as these are likely to have significant impacts on CPP compliance costs and influence allowance or ERC market prices. For example, California is pursuing economy-wide CO_2 emission reductions under AB 32 using a mix of policy measures and a cap-and-trade program, with the CO_2 prices arising from the cap-and-trade program projected to account for about 30% of the overall greenhouse gas emission reductions. Such an approach, along with other factors, resulted in California CO_2 prices remaining at the floor level through the first three years of the program. A greater reliance on market prices to influence emissions would likely require higher allowance prices.

In addition, existing or potential state-level policies could also affect the choice of implementation approach between rate-based and mass-based plans. While states can pursue similar complementary measures under both types of plans, the incentives under each type of plan may look different. For example, states with significant EE programs or renewable energy potential may find funding those efforts by allowing owners to sell ERCs into the market under a rate-based plan to be more attractive than allocating allowances to the program under a mass-based plan or relying on higher electricity prices to incentivize the investments in EE/RE. Such market support through ERC sales may be perceived as more direct or effective. On the other hand, there may be more opportunity for a state to shape the distribution of burdens and benefits under a mass based approach through alternative allowance allocation formulas.

Will the Compliance Approaches Affect Wholesale Power Prices Differently?

One potential argument against adopting a rate-based standard is that it would be administratively challenging to implement due to the need for measuring, verifying, and tracking the ERCs created by both generators and energy efficiency programs. It might also appear that there are operational advantages to using mass-based standards for power plant dispatch and scheduling, However, incorporating the value of ERCs into dispatch orders or supply offers would not be significantly more complex than incorporating the cost of allowances under a mass-based standard.

Under a rate-based standard, units will need to create or obtain a known quantity of ERCs for every MWh generated, depending on the unit-specific emission rate relative to the target emission rate.[13] The following formula describes the number of ERCs a unit creates per MWh of electric generation (or, when negative, the number of ERCs the unit must obtain per MWh of electric generation).

$$\frac{(Target\ Emission\ Rate - Unit\ Emission\ Rate)}{Target\ Emission\ Rate} = ERCs\ per\ MWh\ of\ Generation$$

For units that create ERCs (*i.e.*, renewable energy, nuclear plants, energy efficiency, more efficient NGCCs), the ERCs created can be treated as negative costs (or reductions to dispatch costs). For units that must purchase ERCs (*i.e.*, fossil steam units, less efficient NGCCs), the ERCs purchased can be treated as positive costs (or increases to dispatch costs). In practice, ERCs will function similarly to allowances, with one important distinction: in some cases, ERCs will lower wholesale energy prices, while allowances can only increase prices. This phenomenon occurs when the unit setting the market clearing prices also creates ERCs, lowering its dispatch cost below its marginal fuel and O&M cost.

Figure 8: Impact on Wholesale Electricity Prices of Emission Cap versus Emission Rate

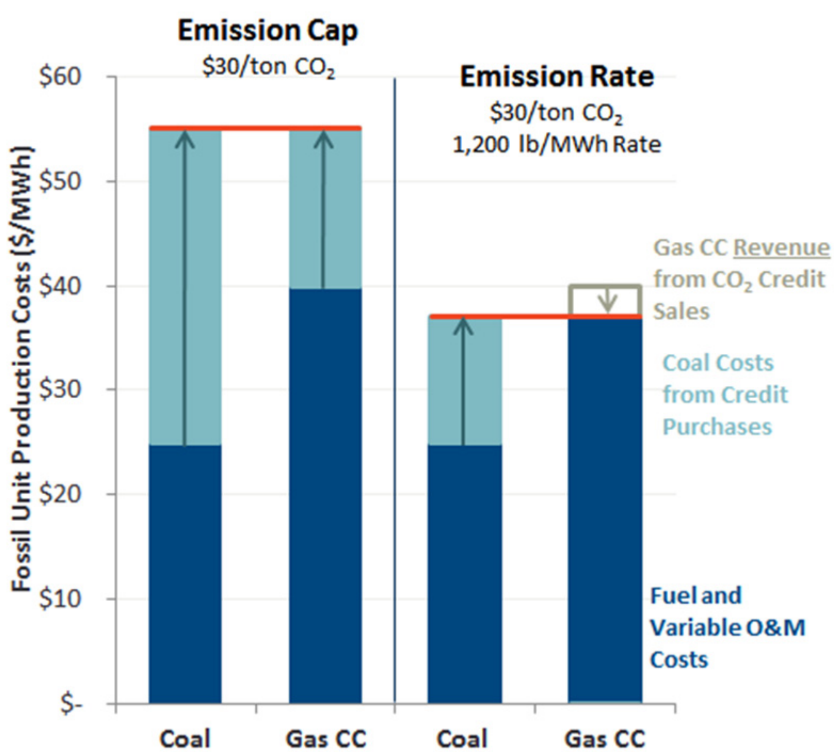

Figure 8 illustrates a simple stylized example of wholesale power prices under equally stringent mass-based standards and rate-based standards.[14] Complying with a mass-based standard will require both

13 To the extent a unit's emission rate varies unpredictably, there will be a small degree of uncertainty regarding the exact number of ERCs created/consumed.

14 Details of the assumptions that underlie this illustration are available from the authors.

coal and gas CC units to obtain allowances for each MWh generated and increase their dispatch costs, while under a rate-based standard dispatch costs may either increase or decrease depending on each unit's emission rates relative to the standard.

This particular example is informative but also highly stylized, and in many instances, a rate-based limit will result in an increase to wholesale power prices (for example, if coal units are often the marginal unit). However, in general, an emission rate limit has a smaller impact on the wholesale energy price than an emission cap that achieves the same CO_2 emission reductions.

Actions Taken by Other States Affect State Compliance

When choosing a compliance path, states need to carefully consider the compliance actions that other states are likely to take. Electricity naturally flows between states due to the interconnected nature of the power grid, and the CPP envisions EGUs in various states trading environmental attributes through compliance instruments such as allowances and ERCs. Therefore, the outcomes of any implementation choice in one state may be influenced by the choices of others.

Neighbors and Friends

There are multiple ways that states' compliance choices affect other states, with two primary pathways through which these effects will transmit between states: power trading among electrically-connected states (which we term "*Neighbors*") and environmental attribute trading (allowances, ERCs, or even RECs) among states with compatible programs ("*Friends*"). Any given state can have few or many Neighbors by virtue of participating in a multi-state regional transmission organization (RTO) or interstate wholesale markets; likewise any state might have few or many Friends by virtue of choosing CPP implementation approaches that allow interstate trading of allowances or ERCs. States are Neighbors by virtue of past decisions, while states can become Friends via their implementation choices under the CPP.[15]

Neighbor states that participate in the same wholesale market will face challenges if they pursue different approaches. Rate-based standards tend to have a smaller impact on wholesale energy prices than mass-based standards. As a result, states adopting rate-based standards that are geographically contiguous with states adopting mass-based standards may see their energy exports increase and/or their imports decrease, effects that will have to be taken into account when evaluating future emissions from their EGU and policy measures to remain in compliance. Likewise, EGU owners such as utilities that operate generation in multiple neighboring states will also have to develop different operating protocols depending on the role that ERCs or allowances play in EGU compliance. We would expect some benefits to arise to the extent that Neighbors become Friends, but the exact magnitude and distribution of such benefits are yet unknown.

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15 While it is possible for Neighbors to change status, for example when utilities switch RTOs, we view these arrangements as fixed for the purposes of this discussion.

EGU owners that operate in single states may be more interested in Friends than Neighbors. The EPA has provided states with many different options for demonstrating compliance with the CPP, but the CPP limits trading between states that adopt different compliance regimes. Choosing a compliance regime that is widely adopted by other states (*i.e.*, many potential Friends) will provide access to a deeper reserve of either ERCs or allowances. This will be an especially important issue for EGUs in states that expect to rely heavily on out-of-state emission allowances or ERCs to reduce CPP compliance costs.

Coordination and Collaboration

The role of Neighbors and Friends on states' choice of a CPP implementation mechanism significantly complicates the analysis of options, and the decision process itself. While only a few situations require outright collaboration between states (e.g., states adopting an average rate implementation option need to blend their average rates in order to trade ERCs between them) the gains from coordination are likely quite high, even if limited to high-level but otherwise reliable knowledge regarding other states' plans.

States might attempt to productively engage on a regional basis to see if rough consensus is possible, but many states would be quite reluctant to offer perceived sacrifices in the interest of the group. A relevant example is multi-state RTO governance. Frequently states object to RTO policy; occasionally they enact policies to counteract RTO decisions. In such cases, the Federal Energy Regulatory Commission (FERC) has ultimate jurisdiction, and states either abide by its decisions or members can look to migrate to another RTO. In the case of the CPP, however, a state objecting to the direction taken by others can simply decide to pursue its own path, or disengage from the group deliberations. The EPA cannot compel engagement in the interest of a regional benefit in a similar manner as the FERC. Despite the potential benefits to affected EGUs, the challenge of encouraging Neighbors to adopt a uniform approach to the CPP implementation may prove insurmountable and states may find it more productive to seek Friends outside of their immediate neighborhood.

EPA Cost Modeling Provides Limited Guidance for State Implementation Decisions

The EPA provided analyses of the CPP in the Regulatory Impact Analysis (RIA), but states and stakeholders should view those results with caution as they consider their compliance options. The RIA analysis is not designed to address issues of state implementation, although it could prove helpful if results were indicative of expected state-level impacts under alternative implementation approaches. Unfortunately, it appears that the RIA analysis yields very limited insights for states looking to harvest those results for guidance.

As with all modeling, the EPA's analysis relies on many important assumptions about the future (with and without the CPP) and while some or most of these assumptions may prove accurate, many other future scenarios are possible. Specifically, the substantial and unlikely near-term coal retirements observed in the base case "business as usual" scenario suggests an improbably small impact on coal capacity arising from CPP implementation.

Additionally, the EPA represents CPP implementation in a manner unlikely to correspond with state choices or approaches. The EPA modeled two policy cases, a Rate Case and a Mass Case, reflecting the assumptions that all states pursue either a rate-based approach or a mass-based approach in order to estimate national-level impacts. In both policy cases, the EPA assumes that the CPP would induce an incremental energy efficiency response equivalent to reducing projected load growth by one percent per year, beginning in 2020 and lasting indefinitely. This exogenous effect ascribed to the CPP implies that load growth will be negligible during the entire decade of the 2020s if the CPP is implemented, and load would be roughly 8% lower in 2030 than projected in the Base Case. These are aggressive targets or expectations relative to past industry experience, especially if past programs have already reduced the scope or raised the cost of remaining efficiency improvements.

In its Rate Case simulation, the EPA assumes that all states impose statewide average rate-based emission standards—meaning that EGUs in different states comply with different emission rate standards. The CPP does not allow interstate trading of ERCs between states with different emission rate standards; however, in the modeled Rate Case, the EPA allows interstate trading of ERCs created by renewable energy or energy efficiency. Thus, the analysis of a rate-based approach does not reflect a constraint that actually applies under the rule, thereby tending to underestimate expected costs.

In its Mass Case projection, the EPA assumes that all states impose mass-based caps on emissions from existing EGUs. The CPP allows interstate trading of CO_2 allowances between states that adopt mass-based standards; however, in the modeled Mass Case, the EPA does not allow interstate trading of CO_2 allowances. This approach reveals regionally differentiated marginal costs of compliance, but it substantially departs from the rule. While states are not obligated to allow EGUs to trade allowances across state lines, the economic advantages make it unlikely that states would forego trading en masse if a substantial number of states pursued that approach. To the extent that the EPA has imposed a constraint in the modeling that does not arise from the CPP, the analysis will tend to overestimate expected costs.

Implementing the Clean Power Plan: The Road Ahead

The 90-day comment period for the proposed federal plan, model trading rules (MTRs), and the Clean Energy Incentive Program (CEIP) began on October 23, 2015. While the basic structure of the CPP has been set in the final rule, these proposed provisions will influence how states approach implementation and how EGUs will approach compliance.

Coincident with the release of the final rule, states and other entities filed multiple lawsuits challenging the legal foundation and perceived harm of the final rule. However, many of the litigants themselves are also engaged in implementation efforts. As Governor Matthew Mead (R-WY) explained, "Certainly we're going to litigate, but we are trying to see what a SIP would look like, a state implementation plan, because all things being equal, I'd much rather have state regulations than the federal regulations. So we're trying to provide as many options as possible, but hopefully we're successful in litigation."[16] This

[16] Interview on E&E TV, October 1, 2015, found at http://www.eenews.net/tv/2015/10/01

litigate-but-prepare stance appears to be the norm for states that oppose the standards, although some states have decided not to proceed with analysis or deliberations as of this writing.

In the period following the initial proposal of June 2014, EGUs and other stakeholders in many states worked productively with relevant state authorities (departments of the environment, as well as utility regulatory commissions) to provide analysis and diverse perspectives for inputs into comments as well as laying the groundwork for collaboration on devising implementation approaches. That was a dress rehearsal for the process that will play out over the next several years as states submit their initial plans in 2016, review those of their Friends and Neighbors, and adjust their plans in 2017, culminating in approvable state implementation plans by 2018. Much work lies ahead for states, utilities, and other stakeholders to craft a reasonable and cost-effective path forward.

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