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Regulating Existing Power Plants under the Clean Air Act: Present and Future Consequences of Key Design Choices

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Contents

INTRODUCTION

On June 2, 2014, the U.S. Environmental Protection Agency (EPA) released proposed rules to regulate existing fossil fuel power plants under section 111(d) of the Clean Air Act. The rules' key features include state-by-state emissions rate targets—based on various "building blocks" of potential emissions reduction strategies—and considerable flexibility to achieve them (Tarr and Adair 2014). This flexibility includes the choice to seek reductions through the combination of strategies identified by the EPA or through some other combination of strategies as well as choices concerning the particulars of the policy mechanisms.

Emissions reductions could be achieved by improving the efficiency of existing coal plants or by shifting, or "redispatching," generation from existing coal plants to existing natural gas-fired plants. New natural gas plants that are already slated for construction could be built earlier than planned to reduce emissions more quickly. Reductions could also be achieved within the existing natural gas- or coal-fired fleets by shifting generation from higher-emitting to lower-emitting plants within those fleets.

Different strategies for emissions reductions and regulation design could have important near-term consequences, in terms of the cost of electricity generation and market prices, and important long-term consequences, in terms of retirements and new investments. These consequences can vary significantly from region to region and from stakeholder to stakeholder.

These long-term consequences may be particularly important in terms of the legacy for future policies. If the Clean Air Act turns out to be an inadequate tool to address future mitigation goals, it could renew debate over federal legislative options, namely, emissions trading, emissions taxes, and a system of tradable national standards. How will the long-term consequences of current regulation affect those choices? Before that question can be answered, the legacy of today's policy choices must be examined.

This paper explores several near- and long-term consequences of key regulatory design choices. Although the current regulatory proposal is oriented toward 2030 targets, the paper's focus is on the post–2020 timeframe, because the important question is not how long the regulations might last, but how soon pressure for an alternative legislative solution might arise. From that perspective, 2020 appears to be a reasonable horizon to imagine such a possibility.

The paper also focuses on national-level policies, even though a key feature of implementation under section 111(d) will be considerable autonomy for state-level decisions. By looking at national-level policies, the analysis can identify effects arising solely from the policy design. Future research might explore state-level variations in national-level policies.

Finally, the paper focuses on the initial consequences of 111(d) choices, not the interaction of those choices with future legislative choices, the next logical research topic.

KEY CHOICES

In establishing the emissions guidelines referenced above, the EPA has discretion over a wide range of factors that can affect emissions and cost outcomes. Following is a discussion of the major choices.

Emissions Reduction Ambition and Horizon

Section 111(d) defines a standard of performance as one that

> reflects the degree of emission limitation achievable through the application of the *best system of emissions reduction* which (taking into account the cost of achieving such reduction and the non-air quality health and

> environmental impact and energy requirements) the Administrator determines has been *adequately demonstrated.*[1] (U.S. EPA 2014d)

In essence, the EPA establishes the emissions reduction goal that it deems is achievable using the best approach that has been adequately demonstrated. Adequate demonstration includes meeting certain benefit-cost criteria; the general notion is that a more stringent reduction goal comes at a higher cost. Thus the EPA must set its ambition commensurate with the cost of achieving it. For example, in proposing new source performance standards (NSPS) for new electric-generating units (EGUs), a proposal that is further along than the proposal for existing units, the EPA determined that coal-fired generation with carbon capture and storage (CCS) has been adequately demonstrated as a viable way to produce electricity with low emissions and thus uses this technology as a determinant of the NSPS (U.S. EPA 2014d).

In the existing source proposal, the EPA examines four "building blocks" that it considers to be adequately demonstrated: performance improvements at power plants, substitution of steam units for combined cycle natural gas, continuation and expansion of low- or non-emitting technologies (nuclear and renewables), and demand-side energy efficiency (U.S. EPA 2014d). Examining each state's potential with regard to each of these options yields a state-level goal. Aggregated to the national level, this goal is estimated to yield between 13% and 18% reductions from the forecast Base Case in 2020 (U.S. EPA 2014c). The EPA also examined a "two building block" approach that includes only performance improvements and dispatch switching. This side case yielded national emissions reductions of 11% to 13% in 2020 and 5% national reductions averaged over the 2016–2020 period.

An underlying question framed by the proposed rule is the appropriate horizon for achieving (and setting) the standard. The proposal focuses on a 2030 date for achieving the specified standard, along with a 2020–2029 period for achieving, on average, an interim standard.[2] There is also an alternative formulation that would focus on a 2025 date for achieving a slightly less stringent standard, along with a 2020–2024 period for meeting, on average, a corresponding interim standard.

This analysis highlights what is likely to occur over the very near term and correspondingly focuses on emissions reductions of 5% over the 2016–2020 period as a basis for establishing conditions that will form the starting point for longer-term action.

Rate-based versus Mass-based Approach

The EPA must decide how to quantitatively specify emissions requirements; states must choose how they will implement those requirements. For the NSPS, the EPA expresses emissions requirements in terms of an emissions rate: tons of emissions per megawatt hour (MWh) of electricity produced. This rate is a transparent metric for EGUs, because all power plants produce the exact same product (MWh of electricity). But plants' use of different fuels to produce their power and the variation in their conversion efficiency leads to different emissions rates across sources.

A rate-based approach is not just easy to communicate; it also provides some flexibility to the sector, allowing for growth in output while limiting its carbon intensity. However, total emissions generated by the sector could actually rise, or at least not fall as much as expected, if increasing output counters the reductions achieved through production of less carbon-intensive power. One way to more directly target EGUs' total emissions is to set a mass-based standard.

[1] 42 U.S.C. §7411 (a)(1) as reported in Monast et al. (2012); emphasis added.

[2] The interim standard is defined as the average of a linearly declining standard from 2020 to 2029. It need not be met in any particular year; it can be met on average over the 2020–2029 period. It is therefore "as if" states faced a linearly declining target from 2020 to 2029, with unlimited banking and borrowing through 2029.

Perhaps the most important distinction between mass- and rate-based approaches arises when they are implemented through a market-based policy: a cap-and-trade for the former and a tradable performance standard for the latter. Similar in many ways to a carbon tax, a cap-and-trade approach puts a price on each ton of reduction. However, a tradable performance standard represents a carbon tax *plus an output subsidy*, sometimes referred to as a "feebate" (Johnson 2006). This standard typically leads to much smaller price impacts for electricity than a cap-and-trade approach.

In its proposal, the EPA established an emissions rate target for each state and provided guidance on how to translate that target into a mass-based target (U.S. EPA 2014b). Whether this formulation will be retained in the final rule remains unknown, as does whether individual states will choose mass- or rate-based approaches in response to whatever rule is finalized.

Thus, this policy analysis compares mass- and rate-based approaches.

Command-based versus Market-based Implementation

A rate-based standard can be strictly applied on a unit-by-unit basis or can allow for trading across units to meet compliance. Strict unit-level ("command-based") compliance means that an EGU must operate below the specified emissions standard or retire. For an existing EGU that operates above the standard, the only possible options under the command-based approach are to switch to a lower-carbon fuel, retrofit the plant to emit lower-than-the-policy rate, or retire, each of which may be costly.

Under a more flexible system, an EGU with emissions over the standard could comply by procuring pollution permits for a price—either through a carbon tax on EGU emissions or through a cap-and-trade program that limits emissions through allowances that can be traded across regulated sources (or purchased as "offsets" from unregulated sources, if allowed).

Typically, carbon tax and cap-and-trade programs are entirely focused on tons of emissions and viewed as mass-based approaches. However, the basic logic can be translated to a rate-based performance standard, as has been done in the case of state-based renewable portfolio standards (RPS) for electric power. In that case, the regulation establishes an overall performance rate (e.g., percent of electricity from renewable sources), but the standard can typically be met for the industry as a whole when individual EGUs purchase renewable energy credits (RECs) that represent units of output (a megawatt-hour of electricity) generated from renewable sources and use these credits as a share of their total generation to compute their "percent renewable" for compliance purposes. Likewise, in the case of a tradable rate-based performance standard for EGUs, some units that operate below the GHG emissions rate can generate additional credits (denominated in tons of CO_2) that can be sold to units that operate above the rate, which in turn use those credits to meet their emissions rate standard. The essential benefit of trading is that it allows a given level of compliance to be met at the lowest cost by exploiting gains from trade between EGUs that exceed the standard (sellers of credits) and those that fail to meet the standard (buyers).

The June 2014 proposal for existing sources does not require states to implement market-based policies. However, the choice to implement a flexible market-based approach—in one form or another—could be the most important choice a state makes to influence costs. This analysis specifically compares such market-based approaches to an approach that does not allow trading (requiring the highest-emitting plants to retrofit or retire).

Single versus Differentiated Tradable Standard

If a tradable performance standard is used to implement EPA guidelines and meet each state's overall emissions rate goal, states could choose to set a single standard for all EGUs or set different standards for different types of units. The primary type of differentiation for EGUs is units that use coal versus units that use natural gas. Of these two main forms of fossil generation, coal generation was responsible for about 40% of U.S. generation in 2013 and emits roughly twice the CO_2 per MWh as natural gas, which accounted for about 26% of all generation (U.S. EIA 2014b).[3] Figure 1 shows the distribution of emissions rates across the forms of fossil generation. The lower-emitting cluster of EGUs to the left are largely natural gas combined cycle (NGCC) units, most of which operate between 750 and 1,000 pounds of CO_2 per MWh; the higher-emitting cluster to the right are coal units, mostly operating in excess of 2,000 pounds of CO_2 per MWh. A relatively small population of steam gas units operates between 1,000 and 1,350 pounds of CO_2 per MWh.

A rate-based emissions standard could be defined as a single threshold for all EGUs. Regardless of where it is set along the spectrum in Figure 1, a single standard is clearly more advantageous for gas units than for coal units. For instance, if the standard is set at the rate of the most efficient coal units, few existing coal units—but virtually all gas units—would meet it. Alternatively, separate or differentiated standards could be set for coal units and gas units so that some existing units of each type are above the relevant standards and others are below them.

Under the single standard approach, all coal plants would likely face higher costs, because they have to buy credits to operate; all natural gas plants would face lower costs, because they are able to sell credits. This approach creates a strong incentive to shift the dispatch of electricity away from coal and toward natural gas. If standards are differentiated, however, particularly to the point at which some coal plants emit less than the coal standard, the dispatch incentives change. The cleanest coal and gas plants will see costs go down (as they earn credits), but the dirtier coal and gas plants will see costs go up (as they buy credits). Hence, there is more switching between coal units and gas units, rather than among coal units and among gas units (Bielen 2014).

In its proposed NSPS, which has a minimum, non-tradable standard, the EPA established different standards for new natural gas-fired plants and coal-fired power plants. In its proposed existing source rule, the EPA avoided any explicit differentiation between the plants. Instead, it assigned emissions rate targets to each state on the basis (in part) of the idea that steam power plants (both coal and gas) would shift toward lower-emitting NGCC units. Essentially, the proposal differentiates the standard by state on the basis of each state's current emissions profile and future reduction potential. The proposal is silent on whether a tradable performance standard, implemented by states, might differentiate between natural gas units and coal units.

Thus, this policy analysis considers both a single tradable performance standard and a differentiated standard whereby the cleanest coal plants would beat the standard specific to coal units.

Inclusion versus Exclusion of New Sources in a Market-based System

Section 111(d) focuses on existing EGU sources that, by definition, were constructed prior to its establishment of new source standards under section 111(b). Under the June 2014 proposed guidelines for existing sources, strategies for compliance with the standards can include end-use efficiency improvements and use of new, non-emitting sources such as renewables and nuclear. Analysis of these strategies is the basis for each state's target. New natural gas capacity (presumably NGCC) built after January 2014 does not influence a state's target or compliance with the proposed existing source rules. However, the EPA requests comment on whether and how new natural gas plants might be included in both setting and meeting state-level goals. In addition, nothing precludes states from including new natural gas plants in whatever regulations they choose to implement, so long as the outcomes meet the defined EPA targets.

[3] Oil emits less CO_2 per MWh than coal and more than natural gas but is a distant third fossil source of electricity in the United States. All other forms of generation are either very low- or zero-emitting sources, such as nuclear, hydro power, biomass, geothermal, wind, and solar, and thus GHG emissions standards are not directly relevant for them.

This analysis models emissions policies whereby new natural gas sources are included in various trading systems and the emissions target for existing sources. This approach limits comparability of the analysis with the EPA analysis conducted on the currently proposed rule, but it provides insights about some of the issues surrounding inclusion of new EGUs for which the EPA has invited commentary.

State-Level Implementation

How will states choose to implement the EPA guidelines? What kinds of policies they will pursue and will they join together as regional trading blocks? In its June 2014 proposal, the EPA examined scenarios reflecting state-level compliance as well as regional blocks. In both cases, the agency considered a tradable performance standard.

For simplicity, this analysis focuses on national-level policies that represent the broadest possible trading approach and does not explore the complex questions of state- or regional-level policy differentiation. The eventual outcome of regional block formation is especially hard to guess.

Policy Scenarios

Table 1 defines four scenarios, all of which target a 5% reduction in the sector's emissions over the 2016–2020 period and assume that policies begin in 2016.[4] The four scenarios are

(1) uniform carbon pricing, as would occur under (mass-based) emissions trading or a tax;
(2) a single tradable performance standard, whereby all fossil generation either requires or earns credits, depending on whether it is above or below the 1,544 lbs/MWh standard;
(3) a differentiated tradable performance standard, whereby coal generation either requires or earns credits, depending on whether it is above or below the 2,095 lbs/MWh standard, and gas generation either requires or earns credits, depending on whether it is above or below the 848 lbs/MWh standard; and
(4) a minimum performance standard, whereby coal generators either beat the 2,144 lbs/MWh standard (perhaps through a retrofit) or retire.

As noted above, the analysis does not differentiate these policies across states or regions. The tradable programs are nationally tradable, with one national market price for emissions credits.

METHODOLOGY

The implications of these policy scenarios are analyzed using the electricity module of the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), which was developed at the Nicholas Institute for Environmental Policy Solutions at Duke University. The DIEM model includes a macroeconomic, or computable general equilibrium (DIEM-CGE), component and an electricity dispatch component that gives a detailed representation of U.S. regional electricity markets (DIEM-Electricity).[5] For this analysis, DIEM-Electricity is run as a stand-alone model, implying that electricity demands are fixed, similar to the way the IPM model is run for the U.S. EPA (U.S. EPA 2013). Given the definition of the policy in question, the approach facilitates interpretation of the model's insights. In other work, DIEM-Electricity has been linked to the DIEM-CGE macroeconomic model, allowing it to incorporate economy-wide responses to policies and evaluate how annual demand levels or fuel prices may change under different policies.

Broadly, DIEM-Electricity is a dynamic linear-programming model of U.S. wholesale electricity markets with foresight. It represents intermediate- to long-run decisions about generation, transmission, capacity

[4] The EPA proposal would require states to meet targets beginning in 2020. States could begin to do so earlier, and EPA modeling contained in the Regulatory Impact Analysis finds that emissions reductions begin in 2016 (even though regulations go into effect in 2020).
[5] For a description, see Ross (2013a, 2013b).

planning, and dispatch of units. To estimate policy impacts, the model minimizes the present value of generation costs (capital, fixed operating and maintenance or O&M, variable O&M, and fuel costs) subject to meeting electricity demands, reserve margins, and any policy constraints. Existing generating units are aggregated into model plants on the basis of their location, characteristics, and equipment configurations to reduce the dimensionality of the mathematical programming problem. New plant options are included using costs and operating characteristics from the *Annual Energy Outlook 2014*, or *AEO* (U.S. EIA 2014a). In addition, the *AEO* forecasts provide annual demand and fuel price forecasts.

Plants in the model are dispatched on a cost basis to meet demand within each region through at least 2050. The version of DIEM-Electricity used in this analysis defines 14 regions along state lines that approximate distinct electricity. Figure 2 shows these regional boundaries, developed from a combination of IPM unit and transmission data, *AEO* regional forecasts, and state-level demand data from the State Energy Data System, or SEDS (EIA 2012). Several individual states are modeled due to their relative importance within broader regions or limitations in electricity flows to and from surrounding states.

Within each region, hourly load duration curves from the EPA (U.S. EPA 2013) are aggregated to show the amount of electricity demand in a number of load "blocks" representing three seasons and four times of day, plus peak demand hours. These 13 load segments convert annual electricity demand into subcomponents to capture the non-storable nature of electricity within a year. Regional annual demand forecasts are defined by combining EIA SEDS data (U.S. EIA 2012) for state-level electricity demand with AEO forecasts for nine Census regions. Post–2040 forecasts are extended along growth trends on the basis of population growth, labor productivity, and estimated improvements in energy efficiency (Ross 2013a).

Electricity to meet these demands is supplied by a combination of existing plants and endogenously constructed new plants. Data on existing plants come from the NEEDS database v.5.13 (U.S. EPA 2013), which characterizes more than 15,000 boiler-generator combinations across all configurations of plant type, fuel source, location, and installed equipment. To maintain computational tractability, these existing units are aggregated into model plants on the basis of common characteristics such as plant type and location, heat rate (btu per kWh), size and age, and existing equipment (flue gas desulfurization, NOx, mercury, and particulate matter retrofits). Non-fossil units are more highly aggregated than conventional fossil units, because they are less likely to adjust their operating levels in response to emissions mitigation policies.

The amount of electricity that existing (and new) model plants can supply depends on the number of hours they are typically available during a year to generate electricity. In DIEM-Electricity, "availability factors" from EPA (2013) are used to characterize how much plants can feasibly operate, taking into account scheduled maintenance and forced outages. When choosing how many hours to run each plant within these bounds, the model considers operating costs of existing units in its cost minimization decisions. Fixed O&M costs are required on an annual basis to maintain a unit, whereas variable O&M costs depend on the number of hours a unit is dispatched during a year. Neither type of costs can be avoided if a unit is to run during any load segment of the year.

The model can build new units in response to demand growth and any changes in the cost structure of the industry resulting from environmental policies or other factors such as changes in fuel prices. Data on new units are from the *Annual Energy Outlook 2014*, in which operating costs are constant across the lifetime of new units and capital costs decrease, depending on the year of installation. In general, decreases in capital costs are linear between the installation ("overnight") costs shown for 2012 and the final year costs in which capital costs improve (2035). Grid connection costs for new units are based on NREL ReEDS data (Short, Blair, Sullivan, and Mai 2009).

Like the EPA IPM and NREL ReEDS models, DIEM-Electricity adjusts overnight capital costs to account for real-world considerations affecting investment decisions. Among these considerations are the time value of money, types of financing options, tax considerations, and construction times for different types of units. These considerations are factored into unit-specific discount rates, which determine a weighted average cost of capital that can be used to calculate a capital charge rate that converts overnight capital costs into a stream of levelized annual payments necessary to recover investment costs.

The model has multiple compliance options to meet either rate-based or mass-based policy targets designed to reduce CO_2 emissions. Coal plants can improve their efficiency (heat rates measured in terms of btus of fuel burned per kilowatt hour of electricity generated).[6] They can also switch among 20 types of coal, defined across production locations and minemouth costs, heat content, sulfur and mercury content, transport costs, and carbon content. Coal switching has the potential to achieve carbon emissions reductions of 3% to 5% assuming, for example, a unit is going from higher-carbon western coal to lower-carbon eastern coal and that the coal is available within a region at a cost-competitive price. More broadly, the model can redispatch generation from higher-emitting sources such as existing coal plants to lower-emitting sources such as existing NGCC plants that may not be running at full capacity. In the longer term, new low- or zero-emitting sources can be constructed to reduce CO_2 emissions.

Most of these compliance options have long been characterized in electricity dispatch models, but the option of improvements in coal-plant heat rates is a relatively new inclusion. Engineering data, notably a report by Sargent and Lundy (2009), tend to show that efficiency improvements are relatively cost-effective.[7] In many cases, these improvements can be economically justified even in the absence of new CO_2 policies, leading to the question of why plants are not undertaking them without GHG policy stimuli.

Historical data show that existing coal units are achieving a wide range of heat rates. However, data are insufficient for researchers to determine how heat rate efficiencies are affected by the available engineering options discussed in reports such as Sargent and Lundy (2009). In the absence of this information, DIEM follows an approach similar to Burtraw, Paul, and Woerman (2011). This methodology essentially assumes that units with high heat rates are likely to have the full range of improvement options shown in Sargent and Lundy (2009), whereas units with low heat rates may have no additional improvements they can undertake. Between these two extremes, the available options decline in a linear fashion. It is also conservatively assumed that units will have tended to install the most cost-effective options first, leaving more expensive options unused. Thus, the capital and operating costs associated with additional efficiency improvements are higher for units that currently have low heat rates as, presumably, they have already installed the most cost-effective options. The Sargent and Lundy data suggest that the approach to determining efficiency improvement retrofits also varies with the size of the unit.

RESULTS

In comparing policy scenarios, this analysis has three main interests. First, how much do the policies reduce emissions and at what cost? Emission reductions are the underlying goal of the proposed EPA regulation and, although cumulative emissions over the 2016–2020 period are fixed across the scenarios considered here, future emissions are not. Costs are clearly important as it is desirable to achieve a given level of reductions at the lowest cost, other factors equal. Second, how do the policies affect capacity choices through 2020? The answer is important if the near-term regulation is envisioned as a foundation for additional future policy measures. Capacity mix in 2020 is a key indicator of the regulation's legacy. Finally, what are the overall price impacts of the scenarios and how do their prices, costs, and emissions rates vary by region? Prices generally reflect impacts on electricity users and regional variation reflects

[6] Such heat rate improvements are generally considered less effective for other types of fossil generators.
[7] See EPA (2014), "Technical Support Document: GHG Abatement Measures" for additional sources and discussion.

the distribution of those impacts. Society will generally prefer the lowest cost possible but may be willing to pay higher overall costs for policies it views as having a more equitable distribution of impacts. Also of concern is whether policies exacerbate or ameliorate current regional differences, because such differences could be viewed as an obstacle to future policies.

Table 2 shows the four policy scenarios' pattern of emissions reductions. All reductions are calculated relative to a baseline projection of future emissions should no new policies be put in place. The scenarios are designed for comparability of near-term emissions reduction; the average reductions over the 2016–2020 period equal 5% in all cases. But the reductions diverge after 2020. At one extreme, the single tradable performance standard leads to almost no reductions in the more distant future, because, even in the baseline, the average fossil emissions rate falls as new natural gas is required to meet future electricity demand. In particular, the baseline emissions rate falls by more than 5% by 2030 and by more than 10% by 2040. With these baseline forecasts, fixing an emissions standard at 5% below the 2016–2020 average rate achieves (virtually) no more emissions reductions after 2030. The policy simply speeds up the pace of emissions rate improvements before returning to the baseline trajectory.

This phenomena represents an important feature of including new natural gas capacity in a tradable performance standard with a constant target, the target can be met naturally over time as newer, more efficient units are built. This contrasts with the recent proposed guidelines by EPA (2014a) that only included existing fossil sources, though the agency requested comment on how to include new sources.[8] Under an existing-source-only tradable performance standard, achievement of a constant target would not necessarily occur naturally, because the new more efficient units expected to come on line are not part of the population of existing sources being regulated.

Under the policy scenarios in this analysis, a differentiated standard has more impact after 2020 than the single tradable performance standard. The shift toward natural gas expected in the baseline does not automatically make the requirements of a differentiated standard easier to achieve as it does for the single standard. Under a differentiated standard, coal and gas units have to, in effect, jointly meet a weighted average of the standard for gas plants and the standard for coal plants, where the weights are the relative shares of coal and gas generation. As total (new+existing) fossil generation shifts toward natural gas, that weighted average target declines under a differentiated standard but not under a single standard. So the natural evolution of lower-emitting gas generation serves a complementary role in emissions reduction under the differentiated standard and as a substitute for other mitigation efforts under the single standard.

A non-tradable standard leads to the largest persistent emissions reductions. Such a standard eliminates a segment of the coal generation fleet that is over the emissions limit and that cannot be sufficiently or cost-effectively retrofitted to meet the limit. This eliminated capacity is gone forever and must ultimately be replaced with additional, lower-emitting combined cycle natural gas, yielding lower emissions in the long term (in the near-term, the eliminated coal capacity can be partially offset by other, unused existing capacity).

The flat carbon-pricing approach provides a continual incentive to reduce emissions, regardless of the baseline emissions rate. However, as the mix naturally becomes cleaner, the approach's effectiveness (in terms of percent reductions) diminishes, because the size of the carbon price relative to the cost of reductions declines in the (naturally over time) cleaner fleet. A fixed or declining emissions cap or an escalating carbon tax, which is typical of most proposals, would have a stronger long-term incentive than the flat tax analyzed here but would be harder to compare side by side with the other policies, which do not escalate over time.

[8] New fossil EGUs are regulated under the proposed NSPS, but at a rate that is not binding for new natural gas combined cycle units (U.S. E.P.A., 2014d).

Against these emissions outcomes,

Table 3 shows the various aggregate cost outcomes. The first column, reflecting immediate costs over the 2016–2020 horizon, shows that a flat carbon price and a single emissions standard are equally low cost. Two caveats are in order. One is that the cost of the flat carbon pricing is presented on a net basis, meaning the costs associated with buying allowances or paying a tax are not counted—only the incremental costs of generation induced by the carbon tax count as net costs of the policy. The tax payment itself represents a transfer to someone else in the economy and thus is netted out of the figures. The transfer does, however, have important distributional implications for those paying the carbon price and those receiving it.[9]

Another caveat is that aggregate electricity demand is held constant. This caveat is particularly important with regard to the apparent equivalence of a flat carbon price and single emissions standard. Column 3 in Table 3 highlights that wholesale power prices are significantly different. As discussed above, a tradable standard can be viewed as a carbon price coupled with an output subsidy. Whereas carbon pricing raises wholesale prices—mainly to reflect the cost of the emitted carbon—a tradable standard *lowers* wholesale prices.[10] In a model *with* demand response, lower wholesale prices would increase the quantity demanded (or at least fail to reduce demand) relative to carbon pricing. If demand were allowed to respond, the lower wholesale price would require more costly mitigation in the power sector to achieve the same ultimate emissions outcome with a higher level of generation. Column 2 of Table 3 shows that carbon pricing is ultimately more expensive than the single tradable standard—but this pricing reflects the additional long-term reductions noted in Table 2.

Examination of the other two policies reveals a somewhat surprising result: the differentiated tradable standard is more costly over the 2016–2020 horizon than the non-tradable standard. The differentiated tradable standard is more flexible than the non-tradable standard; it could, in fact, be met by pursuing the non-tradable compliance strategy—total emissions and generation are the same. The reason that it is more expensive over 2016–2020 horizon, however, is that it is, to a large extent, simply accelerating the low-carbon transition and bringing forward future costs—namely the construction of additional gas-fired plants to meet the regulation in the 2016–2020 timeframe. These plants are built anyway, in the baseline, after 2020. Because of the baseline improvements in emissions rates, noted above, the fleet eventually meets the standard without any changes beyond bringing gas investment forward. Relative to the differentiated standard, the non-tradable standard builds less new natural gas plants over the 2016–2020 horizon, in part meeting the standard by running the coal fleet more cleanly and by closing down the dirtiest coal generators. Ultimately, those coal generators must be replaced and thus more significant costs show up after 2020 in the non-tradable scenario, leading to higher total costs in the long run, as seen in Table 3, column 2.

Capacity and Generation Choices

Costs through 2020 and beyond hinge on generation choices, particularly on new capacity, retrofit, and retirement decisions during the 2016–2020 timeframe to meet immediate compliance obligations. In this analysis's formulation of a constant regulation (emissions rate standards, carbon price) that includes new natural gas generation, compliance obligations are most binding in the 2016–2020 period; efforts to continue to meet targets under each of the four policies diminishes as, even in the baseline case, new natural gas capacity comes on line and the use of coal peaks.

[9] A large portion of the debate over federal cap-and-trade legislation has focused on how to equitably distribute the proceeds from carbon pricing—a concern largely eliminated in discussion of tradable performance standards.

[10] This result of *lower* prices is possible in the short- to medium-run because of existing capital stock in power sector and the ability to shift costs onto the owners of that capital. In the long run, capital has to earn a market return and electricity prices must rise to cover policy costs—though not as much as under carbon pricing.

Figure 3 shows generation by fossil fuel type over the model horizon to 2050, which provides a lens through which to understand the effects of retrofits, retirements, and new capacity, which are shown in Table 4 (in columns 1–3, 4–6, and 7–9, respectively). In Figure 3, carbon pricing and a single tradable standard lead to the largest drop in coal generation and the largest increase in gas generation during the 2016–2020 period. By pricing carbon emissions without differentiating between coal and natural gas generation, these options yield the most substitution from coal to natural gas.

Perhaps the more significant story in Figure 3 is the permanent decline in coal use under the non-tradable policy. Under this policy, high-emitting coal plants are retrofitted to meet the standard or are retired. Although other policies temporarily can have a greater (or smaller) effect on coal generation through carbon pricing, that effect wears off as the sector's capacity and generation mix evolve. Some of this coal generation effect is likely a function of this analysis's particular scenarios—a permanently fixed standard or carbon price and inclusion of new generation in regulation rather than increasing stringency and regulation only of existing sources. As noted above, with naturally improving emissions rates in the baseline, the effects of these policies decrease.

Table 4 provides additional detail. More than twice as much coal is retired under the non-tradable policy (50 GW by 2020) as seen in columns 4-6. This capacity is unavailable in future years to support the increased coal use seen in other scenarios in Figure 3. This lack of coal capacity eventually necessitates additional natural gas capacity. Although increases in natural gas capacity are accelerated in the three other policy scenarios compared to the reference scenario, as seen in columns 7–9, only the non-tradable standard yields additional natural gas capacity (in rough proportion to the lost coal capacity—25 GW) at the end of the policy horizon in 2050.

Returning to the near-term effects in the 2016-2020 period, the differentiated and non-tradable standards have less of an immediate impact on the level of coal generation than the other two policies, because they induce additional efficiency improvements in coal plants. This phenomenon is seen in Figure 4, which shows emissions rates for coal-fired and natural gas-fired plants. Near-term emissions rates among coal plants are much lower under differentiated and non-tradable standards. But compared with the non-tradable standard, the differentiated standard achieves even lower rates for coal *and* natural gas by incentivizing shifts from higher-emitting coal generation to lower-emitting coal generation and from higher-emitting gas generation to lower-emitting gas generation. The non-tradable standard simply requires high-emitting coal facilities to (a) retrofit or (b) retire, both of which lower the average emissions rate for coal and do nothing to natural gas plants. Figure 4 also shows that carbon pricing eventually lowers coal emissions rates.

These improvements in coal-fired generation efficiency come largely from increased retrofits. The retrofit decisions can be seen in more detail in columns 1–3 of Table 4. Early coal retrofits in column 1 are much, much higher under the non-tradable standard and the differentiated standard than under the other policy scenarios. The increase in early retrofits under the differentiated standard arises because CO_2 credit prices are higher than in the other (non-differentiated) trading alternative, as seen in column 7 (as noted above, the differentiated standard only accelerates the timing of this new capacity—the cumulative additions by 2050 are virtually unchanged).

Interpreting these capacity changes in terms of the legacy of different policies requires a focus on permanent changes. The non-tradable standard removes an additional 25 GW of coal-fired capacity that otherwise remains in the other cases. Compared with either the carbon tax or single tradable standard, the differentiated standard leads to more than 200 GW of additional retrofits in 2020; compared with the reference scenario in the long term, it leads to nearly three times more retrofits. Both the non-tradable standard and differentiated standard lead to increases in natural gas capacity in 2020, but neither of these increases is particularly large compared with the increase over the long run. The most important finding for policies achieving the same emissions reductions prior to 2020 is that a non-tradable standard's 2020 legacy is permanently removing more coal-fired capacity than a differentiated standard, whereas a differentiated standard's 2020 legacy is improving efficiency among coal plants, more of which remain in place over the long run than under a non-tradable standard.

Prices and Regional Impacts

The DIEM model allows wholesale electricity prices for all 14 U.S. regions to be calculated. This analysis aggregates those prices to characterize national, aggregate wholesale price impacts. These impacts are shown in column 3 of

Table 3. As noted above, both tradable standards lead to *lower* wholesale prices. This near- to medium-term phenomenon occurs frequently under such standards, because the marginal producer—in this case, gas-powered generation—is enjoying a net subsidy and a downward shift in its marginal cost function. This subsidy is financed by a net tax on coal that erases what would otherwise be profit for owners of coal-fired generation, a phenomenon that will eventually cease as capital turns over.

Pricing emissions without subsidizing clean generation—carbon pricing through either a tax or cap and trade—has the largest effect on wholesale energy prices, and that effect is price increasing, because generators recognize the (opportunity) cost of all their emissions, not just those emissions above the standard. The non-tradable standard raises prices simply because a group of generators—those coal plants that retire—are removed from the dispatch schedule, shifting the aggregate marginal cost curve for dispatch to the left (and upward).

Perhaps more interesting are the regional effects of the wholesale price changes. Figure 5 shows the upward regional price effects for carbon pricing (left panel) and the non-tradable standard (right panel). The price increases are generally lowest in the western regions. This finding reflects cleaner generation, on average, setting prices at the margin. For the non-tradable standard, the price increase is lower in western and eastern regions than the central region and there is greater variability in both the central and eastern regions than the western region. The regions with the highest impacts face the most retirements of higher-emitting coal plants. Price variation in the left panel (carbon price) reflects differences in (mainly gas-fired) emissions rates at the margin, whereas price variation in the right panel (non-tradable standard) reflects differences in where the higher-emitting coal plants, destined for retirement under the non-tradable standard, are located.

Moving to the tradable performance standards, Figure 6 shows the effect on regional wholesale prices from a single standard (left panel) and a differentiated standard (right panel). The pattern in the left panel is similar to the carbon-pricing panel: all of the bars shift downward yet mostly preserve the same order in terms of regional differences. That is, the regions that had the smallest positive increase in the left panel of Figure 5 (e.g., regions in the West) generally had the largest negative decrease in the left panel of Figure 6—both within and across regions.

One goal of the differentiated standard, presumably, is to help shift what might otherwise be viewed as a disproportionate burden away from those regions with higher-emitting generation by setting a less stringent emissions standard for coal-fired generation and a more stringent standard for gas-fired generation. In the right panel of Figure 6, this effect is evident to some extent. Regions in the West go from having some of the largest negative price impacts to having some of the smallest—presumably because their generation is tilted more toward gas. At the same time, however, the variation in price impacts among regions has increased. Two simple measures of spread, the standard deviation of prices across regions and the range of values, both increase. The standard deviation of the price changes go from 0.67% in the left panel to 0.85% in the right panel. The difference between the largest and smallest price change goes from 1.9 in the left panel (Florida versus the Pacific) to 2.8% (California versus Florida).

Part of the intuition for these confusing results comes from Bielen (2014). Although differentiation presents coal-fired generation with a relatively easy-to-meet standard, it also raises the credit price of coal (and decreases the credit price for natural gas). The combination of these two effects can be positive or negative for coal (and gas). Bielen (2014) argues that regions with cleaner coal will generally do better, and regions with dirtier coal, worse.

A second part of the intuition is that, with this analysis's level of differentiation of 2,095 and 857 lbs/MWh for coal and gas, respectively, the cleanest coal-fired plants are receiving a net subsidy and the dirtier gas (actually, all of the steam gas) plants are paying a net tax. In this way, the left panel of Figure 6 is highlighting primarily a coal-gas difference, whereas the right panel is highlighting a clean coal-gas versus dirty coal-gas difference.

Wholesale prices will influence consumer prices in regions with competitive markets; they also will reflect the burden on the marginal generator. Perhaps a better measure for distributional impacts would be some measure of production costs. Figure 7 shows the effect of differentiating the tradable performance standard on total power sector costs by region. Like wholesale prices, variation increases with a move from a single standard to a differentiated standard. Unlike wholesale prices, which are solely determined by the net subsidy or tax of the marginal generator, changes in costs reflect many factors across all producers: changes in generation patterns across regions, changes in mitigation costs, and changes in flows of permit credits across regions. Moreover, generation costs in a given region do not necessarily reflect costs borne by that region, because use (as well as ownership) of generation in one region may occur in other regions. In short, differentiated standards clearly facilitate more coal use and more coal-fired generation compared with the other regulatory options, but the relative regional burdens of the standards are unclear.

A final issue tackled by this analysis is whether regulations are increasing or decreasing the differences among regions in terms of wholesale prices and emissions rates. Lessening differences might be viewed as a helpful step for future policies that otherwise have to deal with the kinds of uneven impacts discussed above. With regard to prices, lessening differences might also reflect a better notion of equity—if price increases are higher in low-price regions. Figure 8 shows how changes in emissions rates on the *y*-axis (e.g., the change in the 2016–2020 emissions for a particular policy relative to the baseline) depend on a particular region's initial emissions rate on the *x*-axis. A situation in which higher initial rates led to more negative changes (e.g., a downward-sloped pattern) would suggest converging rates. Different colors represent different policies (black is the single tradable standard and very similar to carbon pricing's emissions effects; red is the differentiated standard; and blue is the non-tradable standard) and the vertical line shows the average baseline rate. Interestingly, the non-tradable standard (blue) appears to have the effect of lowering the emissions rates in the very highest-emitting region. No such pattern emerges for the other two policies, suggesting that the flexibility provided under both trading scenarios leads the highest emitters to buy their reductions from other emissions sources. Because this option is not available under the non-tradable standard, other forms of mitigation—retrofit or retire—will be necessary.

Figure 9 reveals the results of the same exercise for electricity prices. The change in electricity prices is shown on the *y*-axis (policy – baseline averaged over the 2016–2020 horizon), and the baseline electricity price is shown on the *x*-axis. Here, the differentiated tradable standard (in red) appears to have the desired pattern: it has less negative impact on lower prices, particularly compared with the single-standard (in black).

Figures 8 and 9 show that the non-tradable standard has a somewhat equalizing effect on emissions rates, but the differentiated standard has a somewhat equalizing effect on electricity prices, particularly relative to the single standard.

DISCUSSION AND NEXT STEPS

This paper has explores how certain policy choices related to implementation of power plant regulations might affect emissions outcomes, costs, and future policies, particularly in terms of capacity changes. It also examines policy effects on the regional distribution of emissions rates and wholesale electricity prices. It leads to the following general emissions, cost, and distributional tradeoffs observations:

- A variety of policy designs—emission pricing, tradable standards (uniform or differentiated), and non-tradable standards can be used to achieve near-term emissions reductions of 5% over the 2016–2020 timeframe.
- A tradable emissions standard that remains fixed over time and that includes new generation will create near-term reductions but have little impact on emissions, as emissions reduction actions are shifted over time more than permanently induced. This standard—and its outcomes—differs from the recently proposed EPA standards that (a) strengthen over time and (b) include only existing emissions sources.
- The wholesale price impact of tradable standards, whether differentiated or non-differentiated, is to lower prices by effectively subsidizing relatively low-emitting generation.
- Tradable standards that significantly differ for coal and gas can lead to higher coal generation than those that do not, but at a significant cost. This higher cost arises because of the need to reduce emissions rates for coal *and for gas* rather than just substitute coal for gas.
- Tradable standards that significantly differ for coal and gas lead to more variation in wholesale price impacts across regions than non-differentiated standards—although the pattern of variation reflects smaller decreases in currently low-price regions and larger decreases in high-price regions. In this way, wholesale prices are likely to be more similar across regions after 2020 with tradable standards in place.
- Differentiated tradable standards for coal and gas as well as non-tradable standards have more significant consequences for generation capacity in 2020 than do the alternatives. Differentiated standards will lead to considerably more efficiency investments among coal plants; non-tradable standards will lead to considerably more coal-plant retirements. This difference in the coal fleet, relative to carbon pricing or a uniform tradable standard, could have important consequences for future policies.

These observations raise more questions. First, how might they be affected by regional differentiation of emissions standards in the EPA rules proposed in June 2014? Given the cooperative, federal-state partnership model for regulation under section 111(d) of the Clean Air Act, states may pursue a variety of policy options in response to EPA guidance. How would reasonable views about such differentiation affect the aforementioned observations?

Second, if existing power plant rules are viewed as an interim measure, what are some of the possible long-term policies, and how does the legacy of current regulation affect the relative strengths of these policies? How might different near-term regulations evolve or terminate under long-term options such as a national clean energy standard, federal cap-and-trade program, or federal emissions tax? Do various long-term policies look better or worse owing to near-term regulation? Should the answer to that question affect near-term regulation choices?

The idea of implementing a relatively uniform federal GHG policy operating across all sectors, as contemplated through most of the last decade, is giving way to the reality of a more complicated patchwork of state- or regional-level policies, partly in response to regulation under the Clean Air Act. It is also clear that these policies will likely evolve. Research into these and other questions will be necessary to better inform the choices that the United States faces.

TABLES AND FIGURES

Table 1. Emissions Policy Scenarios.

Scenario	Rate-based or mass-based?	Trading	Same standard for coal and natural gas?	Standard that achieves 5% reductions (2016–2020)
Flat carbon price (emissions cap/tax)	Mass	Yes	Yes	$9/ton CO_2
Single tradable standard	Rate	Yes	Yes	1,544 lbs/MWh
Differentiated tradable standard	Rate	Yes	No	2,095 lbs/MWh coal 856.7 lbs/MWh gas
Non-tradable standard	Rate	No	Yes	2,177 lbs/MWh

Table 2. Emissions Reductions (%) versus Baseline.

	2016	2020	2030	2040	2050
Flat carbon price	-5.47	-4.55	-1.98	-1.88	-2.02
Single tradable standard	-5.44	-4.57	-0.20	-0.03	-0.02
Differentiated tradable standard	-5.73	-4.30	-1.35	-0.95	-0.86
Non-tradable standard	-4.71	-5.28	-6.58	-6.48	-6.50

Table 3. Aggregate Cost and Wholesale Price Impacts (%) versus Baseline.

Policy	Total costs 2016–2020	Net present value of costs, 2015–2040	Wholesale prices
Flat carbon price (net)	0.87	0.66	9.82
Single tradable standard	0.89	0.25	-4.14
Differentiated tradable standard	3.00	0.98	-2.40
non-tradable standard	2.24	1.99	3.72

Table 4. Changes in Capacity (Cumulative Gigawatts).

	1	2	3		4	5	6		7	8	9
	Coal retrofits				**Coal retirements**				**New natural gas capacity**		
	2020	2035	2050		2020	2035	2050		2020	2035	2050
Baseline	6.7	49.7	78.7		21.7	26.5	26.5		19.2	143.9	229.0
Flat carbon price	16.8	129.8	155.0		24.4	29.2	29.2		29.2	149.8	227.1
Single tradable standard	25.4	62.7	78.7		21.8	26.6	26.6		26.8	144.0	229.1
Differentiated tradable standard	216.8	220.3	220.3		21.8	26.6	26.6		44.4	144.3	229.1
Non-tradable standard	92.1	93.5	100.2		50.0	54.8	54.8		36.1	169.7	253.9

Figure 1. Distribution of Emission Rates by Fuel.

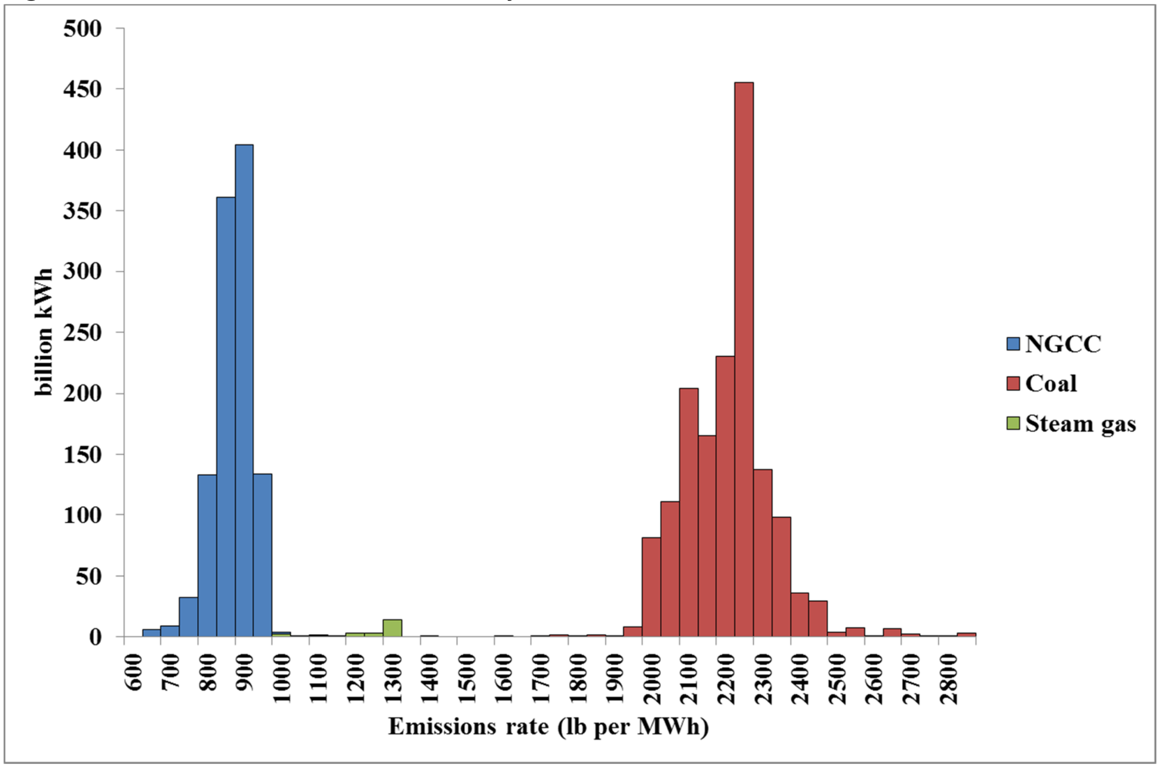


Figure 2. Regions in this Version of DIEM-Electricity.

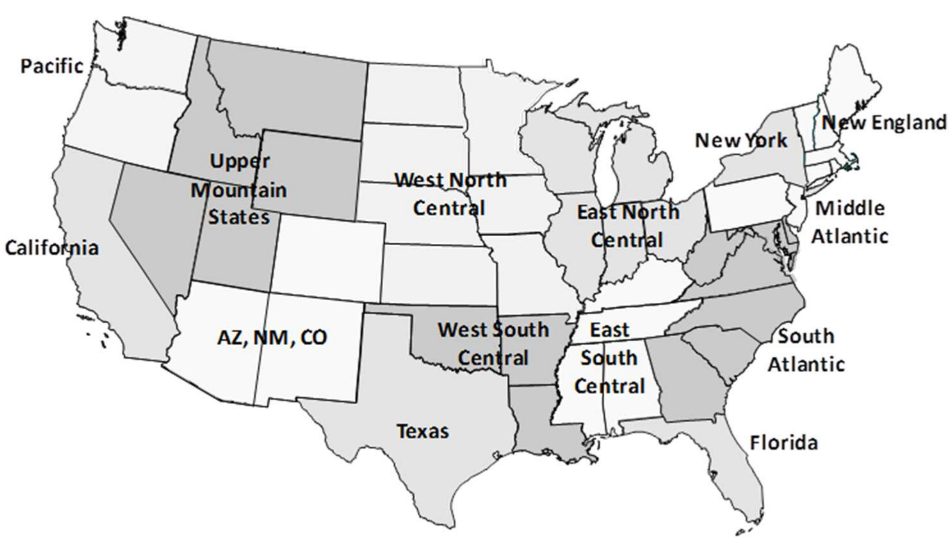


Figure 3. Generation by Fossil Fuel.

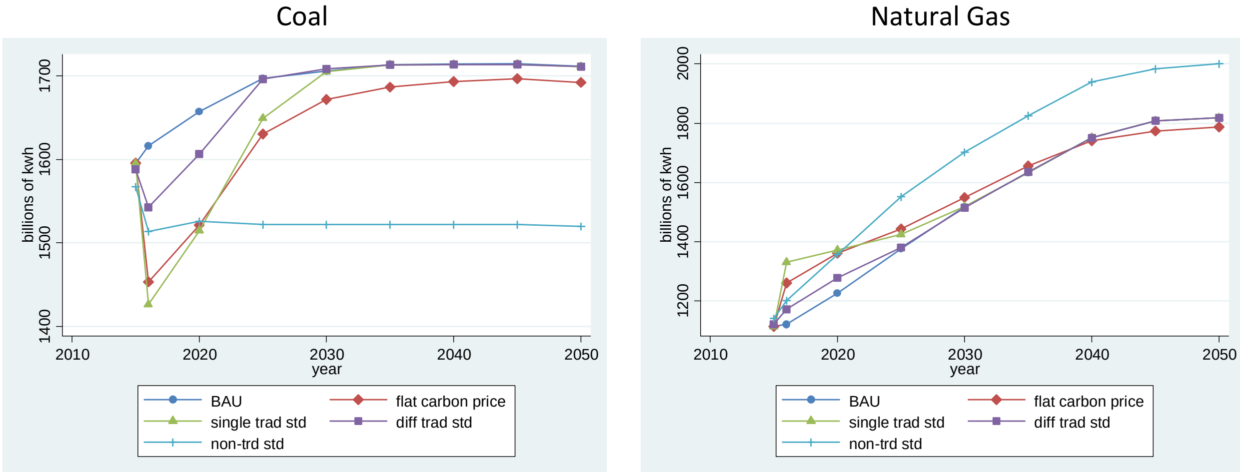


Figure 4. Emissions Rate by Fossil Fuel.

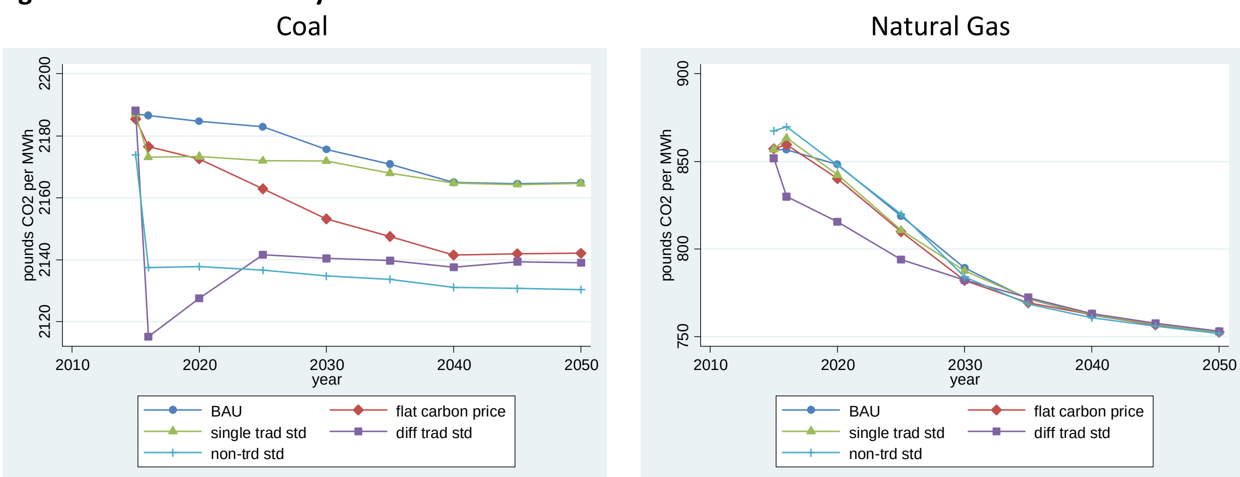


Figure 5. Change in Regional Wholesale Prices Relative to Business as Usual (Averaged over 2016–2020 Horizon): Carbon Tax and Non-Tradable Standards.

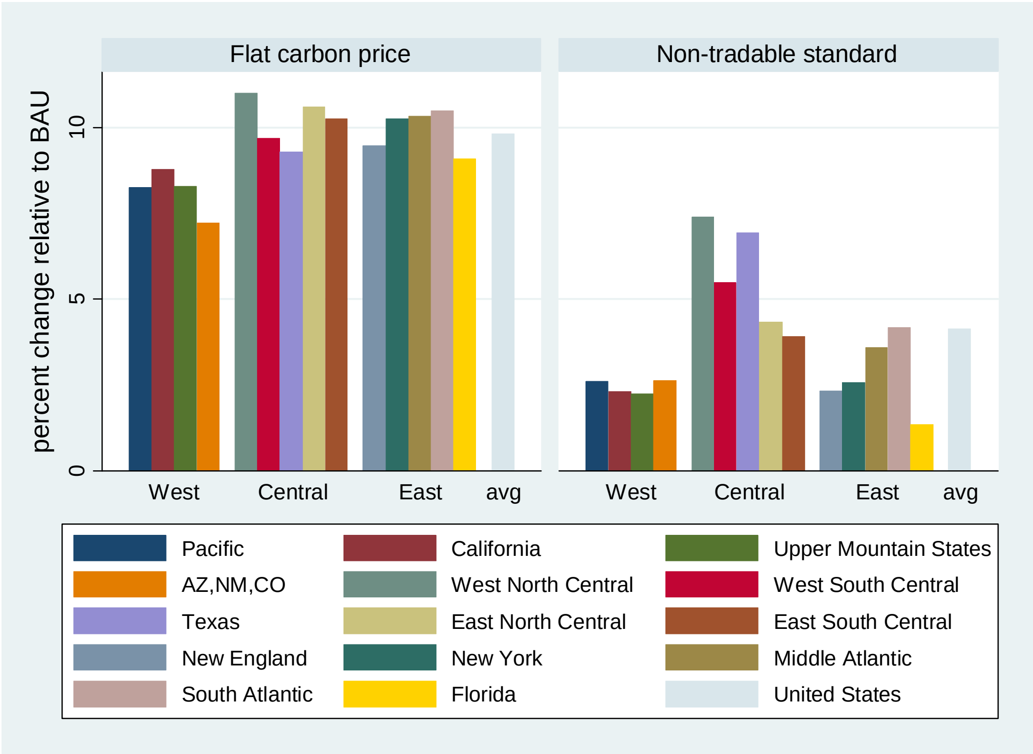


Figure 6. Change in Regional Wholesale Prices Relative to Business as Usual (Averaged over the 2016–2020 Horizon): Tradable Standards.

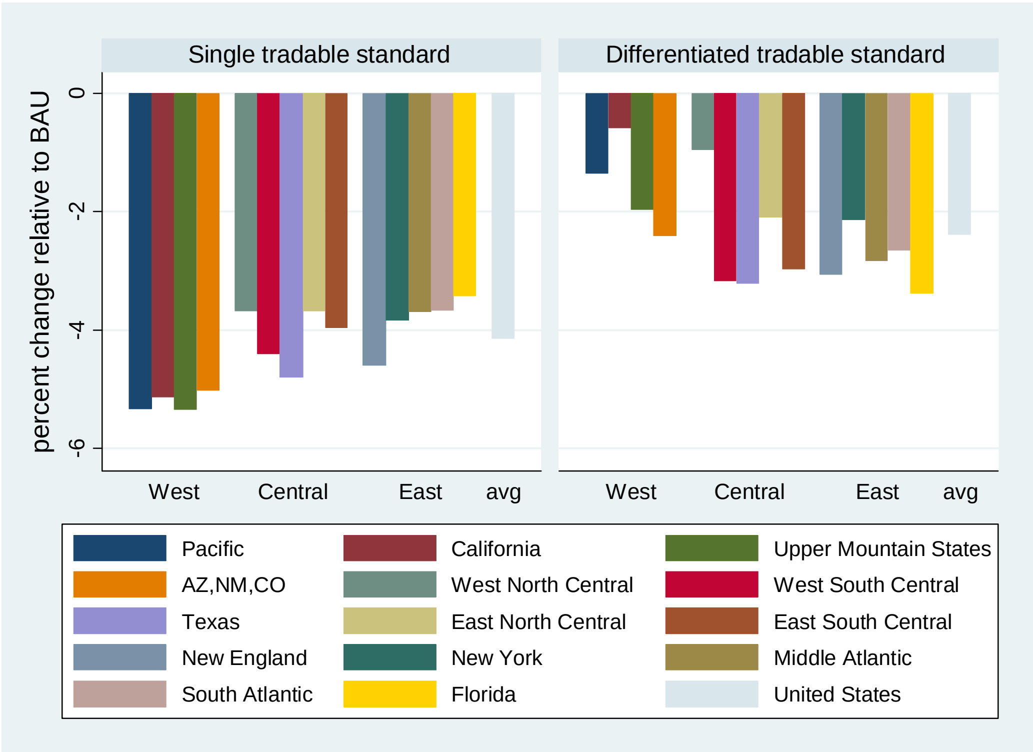


Figure 7. Changes in Electricity Sector Costs Relative to Business as Usual (Averaged over 2016–2020 Horizon).

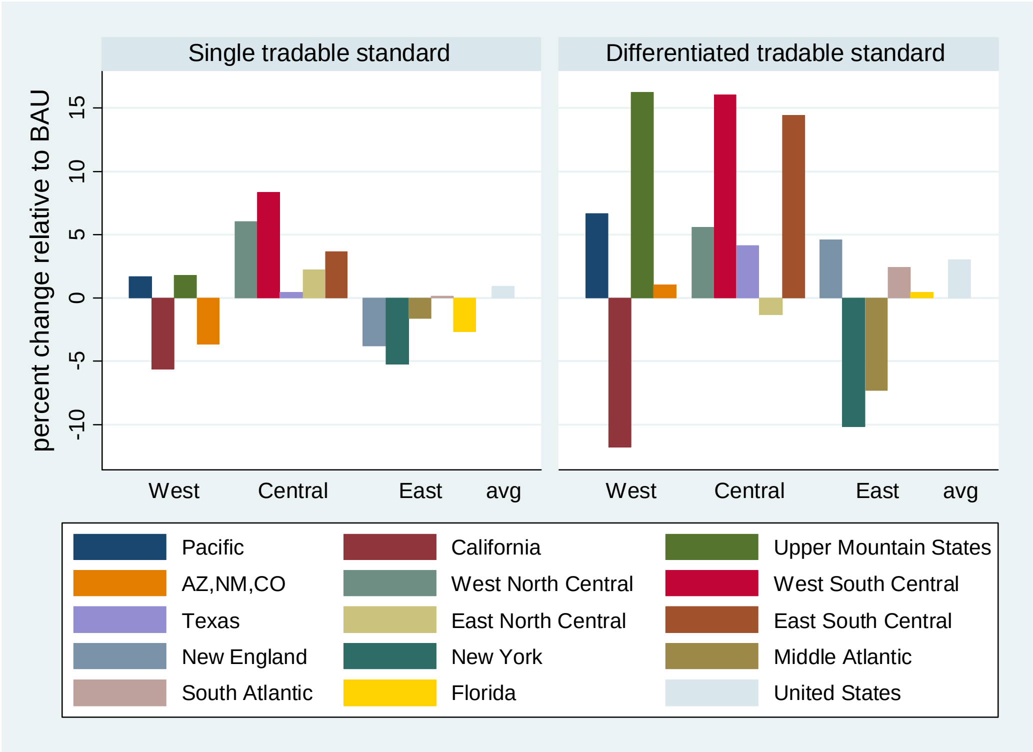
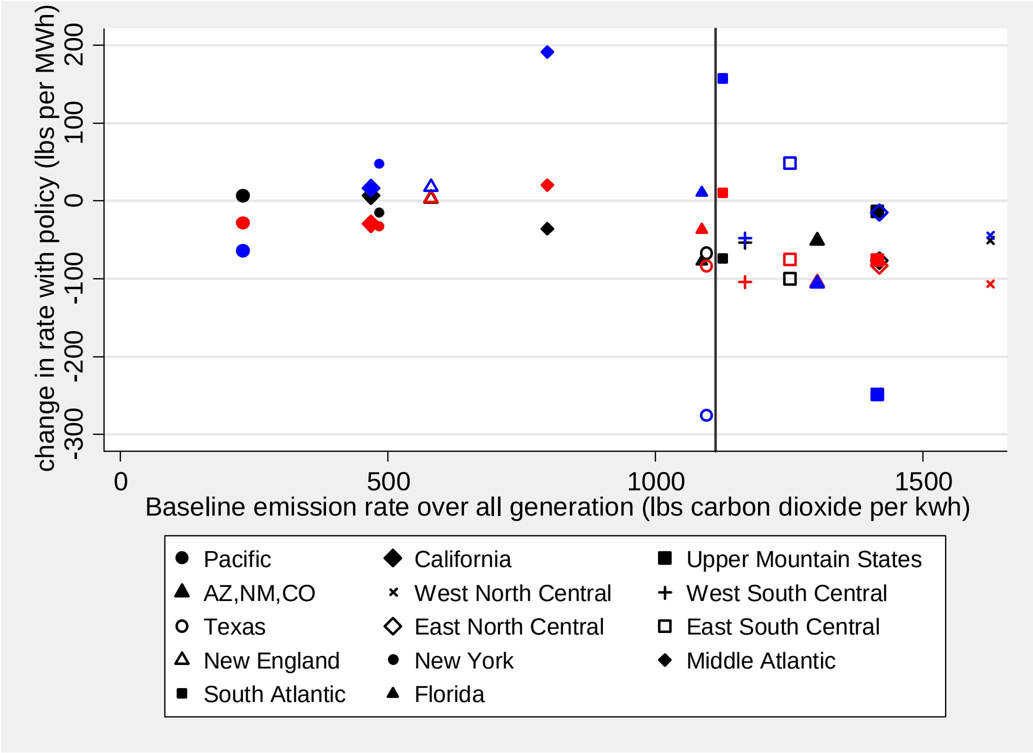
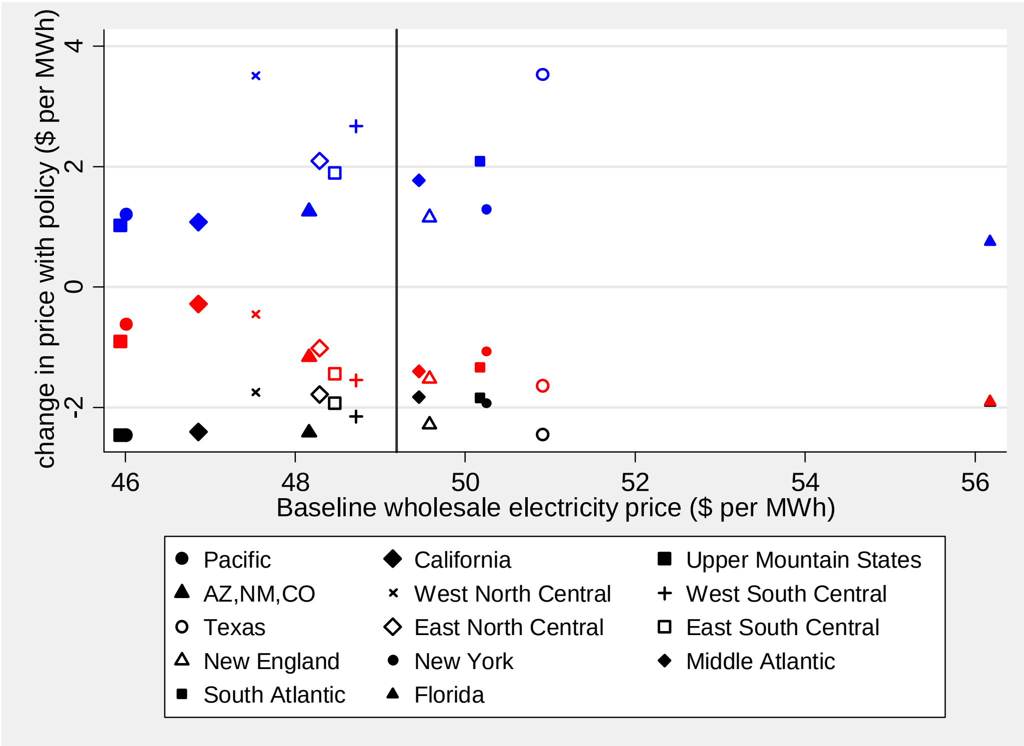


Figure 8. Effect of Policy on Regional Emissions Rates (Averaged over 2016–2020 Horizon).



Notes: Black = single tradable standard, red = differentiated tradable standard, blue = non-tradable standard. The vertical line shows the average emissions rate across the United States.

Figure 9. Effect of Policy on Regional Electricity Prices.



Notes: Black = single tradable standard, red = differentiated tradable standard, blue = non-tradable standard. The vertical line shows the average emissions rate across the United States.

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