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Assessing Impacts of the Clean Power Plan on Southeast States

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SUMMARY

The proposed Clean Power Plan gives U.S. states flexibility in how they attain state-level carbon dioxide emissions rate goals from existing power plants. This analysis explores the potential impact of the proposed CPP on Southeast states across a range of compliance options relative to a baseline without the CPP. The analysis presents modeling results from the Dynamic Integrated Economy/Energy/Emissions Model for eight primary compliance scenarios involving rate-based or mass-based compliance, unilateral state action or regional cooperation, and inclusion or non-inclusion of natural gas combined cycle (NGCC) units as regulated entities under the CPP.

Regarding electricity sector adjustments, the modeling shows that a rate-based approach initially decreases coal generation, encourages use of existing and construction of new NGCC units, and incentivizes renewable generation, although use of renewables is not cost-effective in the Southeast under baseline cost assumptions. By comparison, a mass-based approach initially increases coal generation and removes incentives for use of existing NGCC units while significantly increasing new NGCC generation. Including new NGCC units under CPP compliance shifts generation from those units to existing NGCC units under mass-based compliance and increases coal generation under rate-based compliance.

Regarding policy costs, the modeling shows that individual state compliance costs vary considerably, that a mass-based approach initially entails half the costs of a rate-based approach, and that both regional rate-based and mass-based approaches create significant net cost savings over unilateral state compliance.

Executive Summary

The U.S. Environmental Protection Agency's (EPA's) proposed Clean Power Plan (CPP) regulates carbon dioxide (CO_2) emissions from existing power plants in the United States through state-level emissions rate goals with an interim emissions rate goal from 2020 to 2030 and a final 2030 emissions rate limit. These emissions rate goals are based on each state's 2012 historical generation and emissions from affected units—primarily existing coal and natural gas combined cycle (NGCC) units—as well as opportunities for each state to reduce affected unit emissions on the basis of four "building blocks:" improving the heat rate of existing coal generation, increasing NGCC utilization, displacing covered fossil generation with zero emissions generation, and creating demand-side energy efficiency. The proposed CPP intentionally offers states significant flexibility in compliance, which can be achieved through a mix of the building block actions used to set the emissions rate goals as well as through other measures such as retiring existing fossil fuel-fired units and meeting demand with new natural gas generation. Additionally, the proposal allows states to convert their emissions rate goals into mass-based limits and to enter into market-based multistate compliance plans. The proposed rule also seeks comment on the inclusion of new NGCC units under the state emissions limit.

This analysis explores the potential impact of the proposed CPP on Southeast states across a range of compliance options relative to a baseline without the CPP. The analysis presents modeling results from the Dynamic Integrated Economy/Energy/Emissions Model (DIEM) for eight primary compliance scenarios: individual state rate-based compliance covering existing units, individual state mass-based compliance covering existing units, Southeast regional rate- and mass-based compliance for existing units, individual state rate- and mass-based compliance covering new and existing units (including new NGCC units), and Southeast regional rate- and mass-based compliance covering new and existing units. Additional sensitivities for renewable energy costs, energy efficiency availability, and natural gas prices are also presented.

Regarding adjustments in the electricity industry in the Southeast, the modeling shows the following:

- Under a rate-based approach covering existing units only, coal generation drops by some 45% at the beginning of the policy due to a decrease in utilization and to retirement of 19 gigawatts (GW) of coal generation.
- A rate-based approach covering existing units encourages use of existing NGCC units and construction of new NGCC units. Although a rate-based approach incentivizes renewable generation, use of renewables is not cost-effective in the Southeast under baseline cost assumptions.
- Under a mass-based approach covering existing units only, coal generation is initially higher than under the rate-based option; however, a mass-based approach removes incentives for use of existing NGCC units. New NGCC generation increases significantly under mass-based compliance; by 2030, new NGCC generation more than doubles existing NGCC generation.
- Including new NGCC units under CPP compliance shifts generation from those units to existing NGCC units under mass-based compliance and increases coal generation under rate-based compliance.
- Alternative assumptions regarding capital costs of renewables can lead to higher use of renewables as a compliance option, especially under a rate-based approach. Increased energy efficiency availability and natural gas price variability also lead to shifts in generation responses.

Regarding policy costs in the Southeast, the modeling shows the following:

- Individual state compliance costs vary considerably across the Southeast. Compliance costs for many states in the Southeast also varies significantly between regional compliance and individual state compliance.
- Over the first decade of the CPP policy, a mass-based approach costs approximately half that of a rate-based approach.
- Both regional rate-based and mass-based approaches create significant net cost savings over unilateral state compliance because unilateral compliance means that affected units forgo the opportunity to engage in emissions trading across state boundaries.
- Rate-based and mass-based options covering existing units have little effect on wholesale electricity prices. But including new NGCC units in a rate-based approach lowers prices by subsidizing the units that set wholesale prices; including these units in a mass-based approach increases prices because the units' emissions are faced with additional costs.

How energy efficiency is modeled and accounted for is important. This analysis allows for the possibility of the same energy efficiency investment options in both the baseline and policy scenarios, and the results suggest that these options are cost-effective in the baseline, raising the question of whether their cost savings should be reflected in the baseline or the policy response.

Introduction

In June 2014, the U.S. Environmental Protection Agency (EPA) proposed the Clean Power Plan (CPP) to regulate carbon dioxide (CO_2) emissions from existing power plants under section 111(d) of the Clean Air Act (U.S. EPA 2014a). The CPP establishes state-by-state emissions rate goals for affected fossil fuel-fired units, largely existing coal and natural gas combined cycle generators. A key element of the proposal is its flexibility– states have the ability to achieve emissions reductions through actions such as improving heat rates at coal plants, shifting generation from coal to gas plants that have fewer emissions, engaging in "outside the fence" options such as renewable generation and energy efficiency programs, and can smooth adjustments over the first decade of the policy. States can also choose to allow the use of emissions market mechanisms, wherein some compliance instruments (allowances or credits) can be sold by entities that can generate surplus credits while meeting their compliance obligation to those who need additional credits to meet theirs, either within a state or across states as part of a multistate compliance plan. States can also convert the emissions rate-based goals in the CPP into mass-based targets to achieve additional flexibility. The proposed rule also seeks comment on whether to include both existing and *new* natural gas combined cycle (NGCC) plants under the CPP.

This analysis uses the Dynamic Integrated Economy/Energy/Emissions Model (DIEM) to evaluate possible impacts of the CPP policy (Ross 2014a). The DIEM component applied in this work is a detailed electricity dispatch model of U.S. wholesale electricity markets. It represents intermediate- to long-run decisions about generation, transmission, capacity planning, and dispatch of units. To estimate policy impacts, the model minimizes electricity generation costs while meeting electricity demands and environmental policy goals. Several possible policy scenarios are evaluated:

- State-by-state emissions rate-based goals for existing fossil fuel-fired units as described in the June 2014 proposal,
- Mass-based goals for existing units as described in the EPA's November addendum (U.S. EPA 2014b),
- Rate-based goals for both existing and new fossil fuel-fired units (based on applying the original state rate goals), and
- Mass-based goals for both existing and new fossil fuel-fired units from the EPA's November addendum.

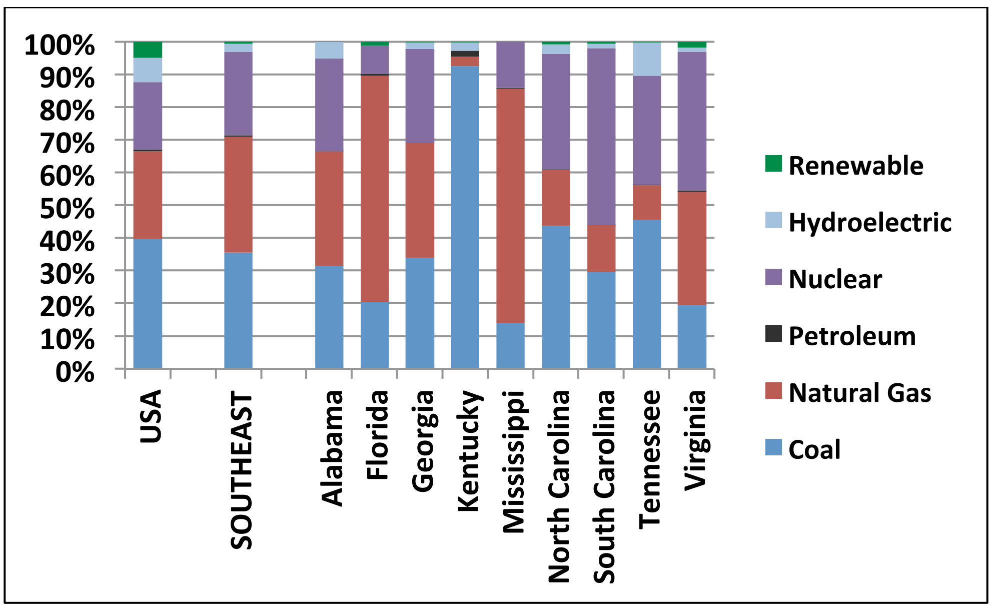
Each of these four options are evaluated under two assumptions regarding level of coordination among states in responding to the CPP: states choose to act alone and states form into regional groups to realize cost-effective reductions available in their immediate vicinity. Only results for the Southeast are presented in this paper; national results are presented in Ross, Murray, and Hoppock (2015).

This paper details the CPP policy and implications of alternative policy responses, provides background information on the electricity sector in the Southeast, and describes the model used in the analysis and the specific policy scenarios that are investigated. It presents policy results for both the Southeast and the region's individual states.

Background

The electricity sector in the Southeast is traditionally regulated; many large investor-owned utilities as well as the Tennessee Valley Authority and cooperatives provide power to the majority of customers. Although Virginia and parts of Kentucky, Mississippi, and North Carolina are part of either PJM or MISO, most of the Southeast is not part of a regional transmission organization (RTO) or independent system operator (ISO). Historically, the Southeast has largely been dependent on coal and nuclear generation, with low renewable generation relative to the rest of the country (Figure 1). Currently, the majority of renewable generation in the Southeast is from biomass and hydroelectric sources.[1] Notably, the Southeast is the only U.S. region constructing nuclear units; five are scheduled to come online over the next decade.[2] Power generation sources vary considerably among states: Florida and Mississippi rely heavily on natural gas, Kentucky relies on coal for more than 90% of its generation, and South Carolina relies on nuclear for more than half of its generation. The large differences in historical generation lead to a wide range of emissions rate goals under the CPP (Table 1): from 692 lbs CO_2/MWh in Mississippi to 1,763 lbs CO_2/MWh in Kentucky.

Figure 1. Generation shares by region and state in 2012

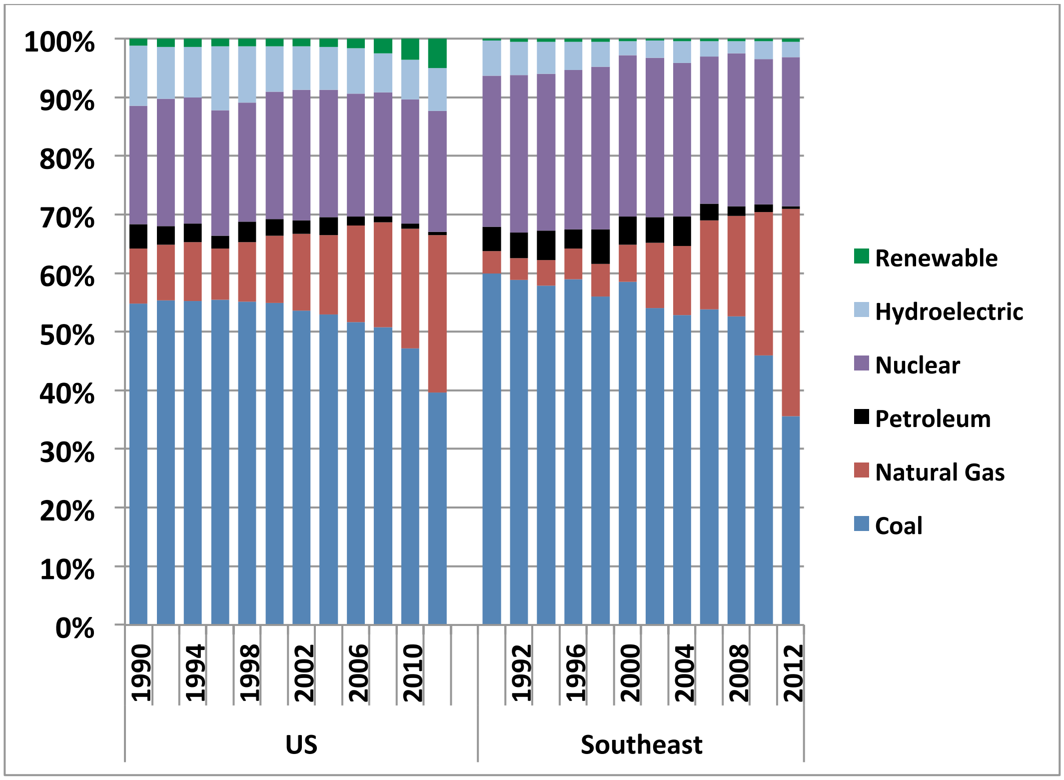


Source: Authors' calculations based on U.S. Energy Information Administration (EIA) state historical data (U.S. EIA 2015).
Note: Generation is by electric utilities and independent power producers.

[1] Most biomass generation in the Southeast occurs in industrial combined heat and power.
[2] Watts Bar 2 in Tennessee, Vogtle 3 & 4 in Georgia, and VC Summer 2 & 3 in South Carolina.

Across the nation, the electricity sector has undergone a significant shift in generation over the last decade as natural gas prices have fallen (Figure 2). This trend is even more pronounced in the Southeast than in the United States as a whole. The Southeast was more but is now less dependent on coal than the country in aggregate.

Figure 2. Generation shares by region, 1990–2012

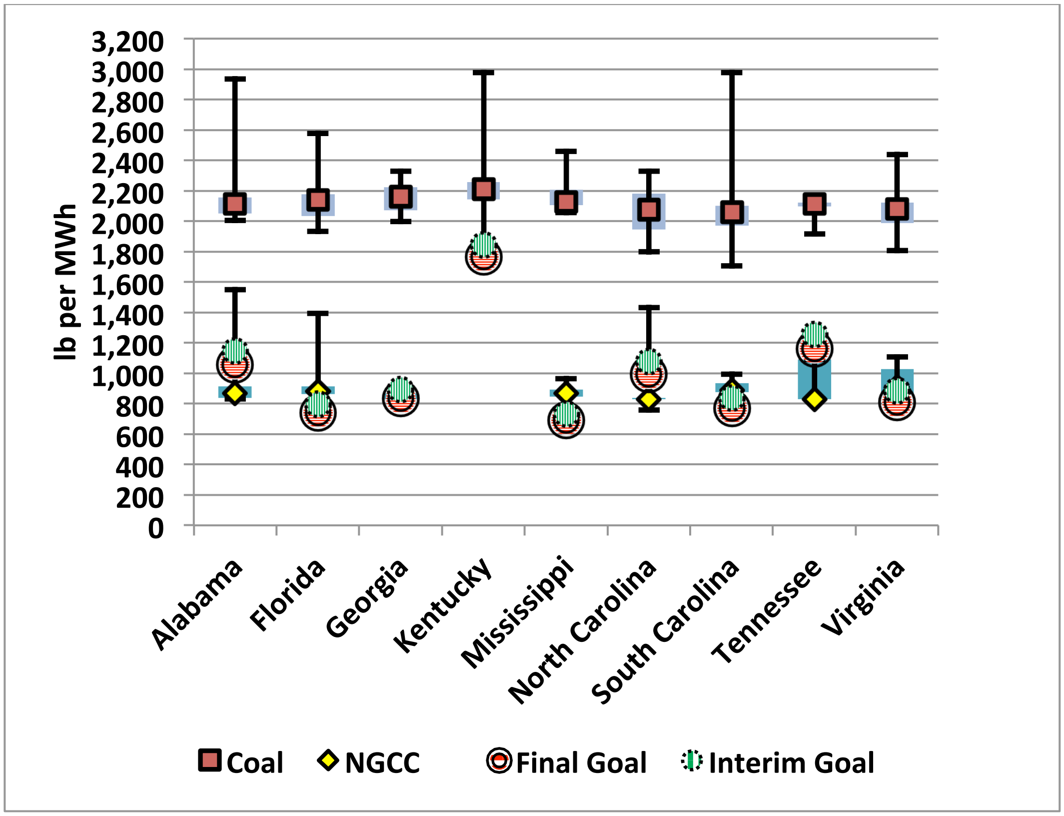


Source: Authors' calculations based on EIA state historical data (U.S. EIA 2015).
Note: Generation is by electric utilities and independent power producers.

As discussed in the EPA proposal (U.S. EPA 2014a), the CPP lays out a detailed series of calculations, starting with historical data on generation and emissions, and applies four "building blocks" to estimate state-by-state emissions rate goals that are feasible extensions of current technologies and policies and future capabilities to achieve emissions reductions. The calculations reflect engineering data on possible heat rate improvements at existing coal-fired plants and suggest that units can potentially improve efficiency by 6% over current levels. They assume that use of existing natural gas combined cycle (NGCC) plants can be increased and that generation at coal-fired plants can be reduced to take advantage of the higher efficiency of NGCC units and the lower carbon content of natural gas. The calculations also reflect potential measures to maintain under-construction and "at risk" nuclear plants and to expand renewable portfolio standards (RPS) in some states to surrounding states in order to expand zero-emitting generation sources. Finally, using historical trends in the data, the calculations estimate the capacity of states to achieve energy efficiency savings in electricity demand.

Figure 3 shows the interim (2020–2029) and final (post-2029) emissions rate goals for the nine states included in the Southeast region as defined in this analysis (see Ross, Murray, and Hoppock 2015 for a discussion of other regions). These goals are contrasted to the underlying data on existing coal and NGCC units used in the DIEM model. For the year 2012, these data present the total range of emissions rates for generating units (shown by the vertical bars for each category) and for the second and third quartiles that cover the majority of units of each type (the shaded bars). The boxes within the quartile ranges represent the medians for coal units; similarly, the diamonds show the median for existing NGCC units. The contrast of these initial emissions rates with individual state goals suggests the potential difficulties in meeting these goals.

Figure 3. Emissions rates and goals for coal and NGCC units in the Southeast (2012)



Source: Authors' calculations based on NEEDS data (U.S. EPA 2013).

Table 1 contrasts the final goals from Figure 3 with the mass-based goals calculated by the EPA in its rate-to-mass technical support document (U.S. EPA 2014f). These mass goals are provided for a policy approach that covers only existing fossil fuel-fired units ("Mass from Existing") and an approach that covers both existing units and new NGCC units that are estimated to be needed to meet electricity demand growth in each state ("Mass including New NGCC"). The future mass goals for 2030 can be compared to historical emissions in 2012 from the same fossil sources ("Emissions in 2012 from Existing Affected Sources"). These data show that the mass goals represent emissions decreases ranging from 15% to 52% across southeastern states.

Table 1. Emissions goals in the CPP for southeastern states in 2030

	Emissions Rate Goal (lb/MWh)	Emissions in 2012 from Existing Affected Sources ($MMTCO_2$)	Mass from Existing ($MMTCO_2$)	Mass including New NGCC ($MMTCO_2$)
Alabama	1,059	68.6	50.3	59.2
Florida	740	107.5	68.2	83.3
Georgia	834	57.0	31.7	42.4
Kentucky	1,763	82.9	70.2	82.0
Mississippi	692	23.5	16.4	18.9
North Carolina	992	53.2	36.9	45.2
South Carolina	772	32.6	15.8	22.0
Tennessee	1,163	37.4	22.8	33.0
Virginia	810	24.9	18.9	24.5

Source: U.S. EPA (2014d).

Methods

Policy scenarios are analyzed using the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), developed at Duke University's Nicholas Institute for Environmental Policy Solutions (Ross 2014a, 2014b). DIEM includes a macroeconomic, or computable general equilibrium component (DIEM-CGE), and an electricity dispatch component that provides a detailed representation of U.S. regional electricity markets (DIEM-Electricity). For this analysis, DIEM-Electricity is run as a stand-alone model, implying that electricity demands are fixed at their future forecast levels, aside from any energy efficiency considerations, which is standard treatment for U.S. EPA policy analysis (U.S. EPA 2013).[3] Given the policy in question, this approach facilitates interpretation of the model's insights.

Broadly, DIEM-Electricity is a dynamic linear-programming model of U.S. wholesale electricity markets with intertemporal foresight regarding future market conditions and electricity policies. It represents intermediate- to long-run decisions about generation, transmission, capacity 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, which are based on data from the National Electric Energy Data System (NEEDS) database v.5.13 (U.S. EPA 2013), are aggregated into model plants on the basis of their location, characteristics, and equipment configurations

[3] Although electricity demands are fixed when DIEM-Electricity is run by itself, there are flexible supply curves for coal, natural gas, and biomass within its electricity component. The fossil fuel supply responses are based on elasticities implied by the AEO resources side cases, and the biomass supply curves come from the EPA (U.S. EPA 2013).

to reduce the dimensionality of the mathematical programming problem.[4] New plant options are included using costs and operating characteristics from 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 2050. The version of DIEM-Electricity used in this analysis includes 40 electricity markets, defined along the 48 continental U.S. state lines. These regional boundaries and the associated state electricity demands are developed from a combination of the U.S. EPA's Integrated Planning Model (IPM) unit and transmission data (U.S. EPA 2013), AEO regional forecasts, and state-level demand data from the State Energy Data System, or SEDS (U.S. EIA 2012). 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." These blocks convert annual electricity demands from the AEO into subcomponents to capture the non-storable nature of electricity within a year.

The model has multiple compliance options to meet the CPP policy targets designed to reduce CO_2 emissions, all of which are endogenous choices within the model (i.e., the model can choose whichever options are the lowest-cost responses to the policy). These choices cover all four of the building blocks used by the EPA to define state emissions rate goals. First, coal plants can improve their efficiency (their heat rates measured in terms of Btus of fuel burned per kilowatt hour of electricity generated).[5] Second, generation from higher-emitting sources such as existing coal plants can be redispatched to lower-emitting sources such as existing NGCC plants that may not be running at full capacity, assuming this policy response is cost-effective. Third, new low- or zero-emitting sources can be constructed to reduce CO_2 emissions.[6] And fourth, DIEM can make endogenized choices related to energy efficiency, which can reduce electricity demand and count toward state emissions-rate goals under the CPP.

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

Historical data show that existing coal units operate under 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 et al. (2011) and assumes that units with high heat rates have the full range of improvement options shown in Sargent and Lundy (2009), whereas units with low heat rates have no additional improvements they can undertake. In contrast to the EPA analysis (U.S. EPA 2014d) that assumed a 6% improvement was available to all plants for \$100/kW in the CPP policy scenarios (but not the EPA baseline), the approach in DIEM implies that a more limited set of plants have heat rate improvement options available that are in the 2%–3% range. These options are available in DIEM in both the baseline and policy scenarios, in which average realized costs to plants that choose to install the measures based on their economics tend to run in the neighborhood of \$50–\$60/kW.

DIEM can select energy efficiency measures in both the baseline and policy scenarios if they are a cost-effective alternative to generating the same amount of electricity within the electric sector. First-year costs and lifetimes of the measures are based on EPA data, which assume an initial cost of \$770/MWh for

[4] Data from U.S. EIA (2015) are added to account for recent construction and retirement decisions.
[5] They can also switch among 20 types of coal, defined across production locations, coal characteristics, and carbon content—a flexibility that has the potential to reduce carbon emissions by several percent. Biomass and natural gas co-firing are not allowed as options in the baseline or as measures that count toward CPP policy goals.
[6] It is assumed that new nuclear plants do not count toward calculation of emissions rate goals.

most years of the policy and an average lifetime of 10 years (U.S. EPA 2014d). The quantity of efficiency measures available is, in most years, sufficient to reduce electricity demand by 1.5% from the previous year's demand, before consideration of annual demand growth that also occurs in the current year. Following the EPA analysis, it is also assumed that utilities and program participants split the costs of the measures equally. As a general rule, at the prices in the EPA analysis, the model finds that it is cost-effective to adopt the efficiency measures in both the baseline and policy scenarios, the implications of which are discussed below.

Policy Scenarios

The CPP policy scenarios in this paper focus on the emissions goals defined as "Option 1" in the EPA's illustrative analysis in the regulatory impact analysis RIA (U.S. EPA 2014d). These options define an interim goal that must be met on average over the 2020–2029 decade. For 2030 and later years, the final goal described in the EPA's calculations must be met in each 5-year time period in the model. This analysis examines these emissions goals using both the rate-based approach defined in the RIA and the comparable mass-based approach defined in the EPA's translation of state-specific rate to mass equivalents (U.S. EPA 2014f).

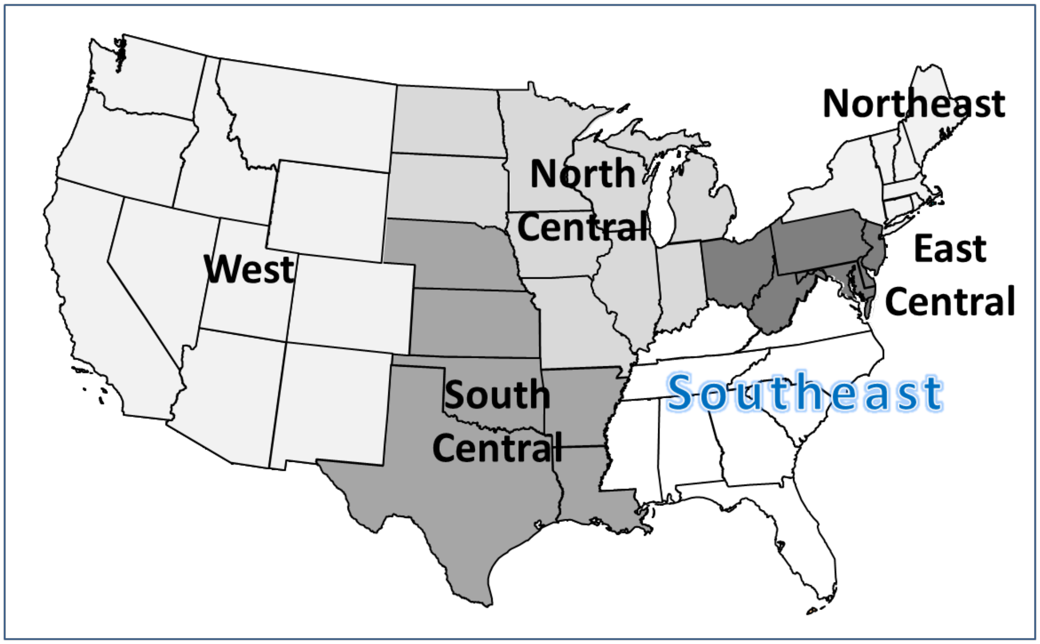
These goals are used to define four main sets of policy scenarios:

- Rate-based trading among existing fossil fuel-fired units ("Rate"), in which the state emissions rate goals shown in Figure 1 are applied to emissions from affected fossil sources, which include existing fossil fuel-fired steam boilers larger than 25 MW, existing NGCC units larger than 25 MW, and combustion turbines larger than 25 MW that run at a capacity factor greater than 33% and that generated more than 219,000 MWh in 2012.[7]
- Mass-based trading among existing fossil fuel-fired units ("Mass"), in which the state mass goals calculated by the EPA are applied to the same universe of affected fossil sources.
- Rate-based trading including new NGCC ("Rate w/New NGCC"), in which the state emissions rate goals from the "Rate" scenario are also assumed to apply to new NGCC units. Bringing these units into the trading system will tend to loosen the policy as new combined cycle units have emissions rates around 750 lb/MWh, which is below the rate goals of some two-thirds of states.
- Mass-based trading including new NGCC ("Mass w/New NGCC"), in which the EPA-calculated state mass goals, including an adjustment for new NGCC units, are used. The calculation of these goals assumes that future electricity demand growth is met in states through construction of new NGCC units.

Each of these four sets of scenarios is examined using two alternative assumptions about the geographic scope of trading among covered sources.[8] First, it is assumed that states act alone to meet their individual state emissions goals ("State" scenario). In this case, the emissions rate or mass must be met through actions in each state without trading of emissions allowances with other states, although this assumption does imply fully efficient trading of obligations within each state. Second, it is assumed that states form trading blocks to take advantage of any cost savings that can be achieved through trading obligations with states that possess lower-cost methods for meeting regional goals ("Regional" scenario). Figure 4 shows these regional groups, which generally follow the zones defined in the EPA's RIA (U.S. EPA 2014d), with the exception that Virginia is considered part of the Southeast region that is the focus of this analysis.

[7] Tribal units are excluded from the policy.
[8] It is assumed that all regions of the country follow the same rate-based or mass-based approach to CPP with the same method of allowance trading, rather than attempting to predict which states or regions are likely to choose which approach.

Figure 4. Regional trading blocks



It is assumed that when states act together to meet emissions goals they keep their originally defined state goals and work to meet a regional emissions target that is the generation-weighted average of the state goals. In the case of rate-based goals, this approach will tend to incentivize some shifting of the generation mix as states attempt to take advantage of looser emissions rate targets in some states than in others. It is unclear if this approach would be allowed under the CPP, but it also seems unlikely that states with looser goals initially would agree to enter into regional trading agreements if doing so meant adopting a tighter regional average rate goal.

After the four sets of policy scenarios are covered, the modeling is extended to include sensitivity analyses of renewables, energy efficiency, and natural gas prices. Examining possible alternatives for these three critical factors in meeting states' goals helps illustrate some important drivers in the CPP policy and in DIEM's findings.

Results

The analysis begins with an examination of the generation impacts of the CPP under the four main policy scenarios. Generation changes are a useful metric to summarize the overall implications of changes in both availability capacity through retirements and new construction and plants' utilization rates. Fuel demands will also largely follow these generation patterns. The analysis then compares the effects of some state-specific generation changes on alternative methods of CPP allowance trading and on new capacity and utilization rates. Finally, it examines policy costs under the alternatives and explores some of the variation in state impacts.

Generation

Generation across the Southeast for the four categories of plants most affected by the policy—existing coal and NGCC units, new NGCC units, and existing plus new renewables (excluding hydroelectric and biomass)—is shown in Figure 5 for 2020 and 2030, representing the initial year of the policy and the year in which it is in full effect. In examining the baseline and policy generation in this, and subsequent, figures, DIEM is allowed to choose the energy efficiency measures defined by the EPA, if it is cost-effective to do so, and does choose to fully adopt these measures at the prices defined by the EPA, assuming a 50-50 split between utilities and consumers. This means that electricity demand in the baseline forecast and all policy cases across the United States is roughly 3% lower than AEO forecasts in 2020, 8% below AEO forecasts in 2025, and 11% below AEO forecasts by 2030.

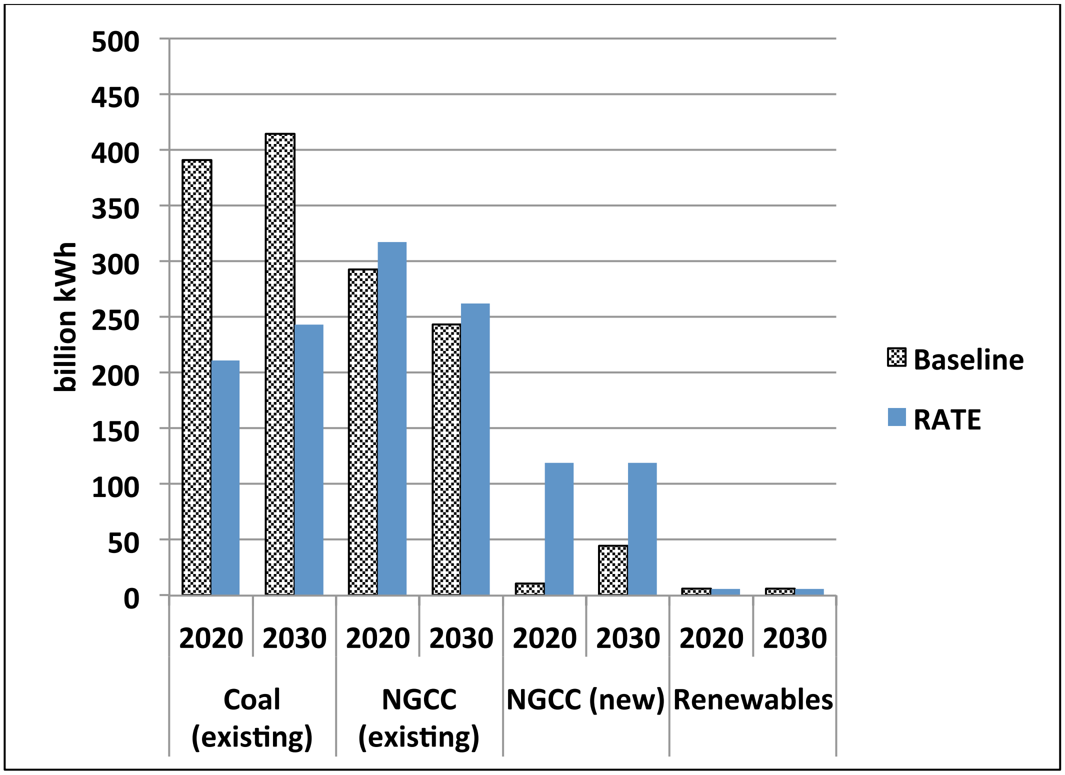
Under a regional rate-based approach, coal generation drops significantly when the policy takes effect in 2020, although it does recover slightly over time. Part of the drop comes from retiring 19 GW of coal generation in response to the CPP from baseline levels of 65 GW (after accounting for both existing policies such as MATS and lowered demand due to energy efficiency savings in the baseline).[9] The rest of the 2020 decline in coal and subsequent recovery comes from changes in utilization rates, as shown in Figure 9. The coal retirements in the Southeast comprise two-thirds of all coal retirements across the nation and one-half of the total decline in coal generation, even though baseline coal generation in the Southeast represents roughly 25% of the U.S. total. This decline occurs in the Southeast under a rate-based approach largely because the region does not have access to cost-effective renewables to offset the emissions rates of coal units, although this result for renewables is dependent on the model's baseline wind and solar capital costs, as will be demonstrated in sensitivity analyses.

The incentive structure implicit in the CPP emissions rate calculation tends to encourage generation by existing NGCC units, which have a lower emissions rate than coal units (the CPP also acts to incentivize zero-emitting renewables such as wind and solar, but they are not considered cost-effective given baseline assumptions in the model).[10] As shown in Figure 9, the model does not consider it economic to redispatch generation from coal to existing gas units at the 70% rate used in the CPP calculation, but generation from existing NGCC units does increase in the CPP's early years.

9 Existing NGCC units do not tend to retire under a rate-based approach to the CPP, although some of these units do retire by 2030 under the mass-based alternatives.

10 DIEM uses average improvement rates in renewables costs based on EPRI's US-REGEN model (Blanford et al. 2014), which are somewhat quicker than those in EPA's IPM model. Over the 2015–2030 time frame, the authors' calculation of these average improvement rates in capital costs for onshore wind average 0.91% per year, compared with EPA's 0.73% per year. Over the same time frame, solar PV costs in DIEM based on these calculations improve 2.38% per year, compared with the EPA's 1.16%.

Figure 5. Southeast generation under rate-based regional trading



Note: Renewables excludes hydroelectric and biomass sources.

Under the CPP, costs are imposed on existing coal and gas units affected by the policy. These costs provide an incentive for generation to shift more quickly into new NGCC units than would be the case in baseline forecasts. This effect appears as the expansion of new NGCC generation shown in Figure 5. The increase in NGCC generation by 2020 represents the model's estimate of the most cost-effective response to the CPP, assuming that utilities begin planning for the policy at the beginning of the model horizon in 2015 and that they face no significant constraints on their capacity to build the desired amount of new NGCC units in the Southeast.[11] Were this response in NGCC construction delayed, overall policy costs would increase, and additional adjustments would likely be required in the existing fossil fleet to meet the CPP emissions rate goals over the 2020–2029 time frame.

Figure 6 compares the Southeast generation results based on regional trading of allowances (as shown in Figure 5) with generation results based on intrastate trading. As discussed below, intrastate trading is significantly more costly. The factors driving its higher costs can be seen in state-level adjustments for state rate-based generation compared with regional rate-based generation. In broad terms, coal and existing NGCC generation are forced to decrease more to meet states' emissions rate goals, leading to additional new NGCC construction. The bulk of the coal reductions come from a few states such as Kentucky and Tennessee, which presumably have comparatively less efficient units. In states with low emissions rate goals compared with other states in the Southeast region—Mississippi, for example—these coal reductions lead, at a cost, to the need to construction more NGCC units to meet electricity demands.

[11] There are national constraints on NGCC construction rates based on maximum construction rates in AEO side cases; however, there are no region-specific or state-specific limits on builds.

Figure 6. Regional versus intrastate rate-based trading among existing units (2030)

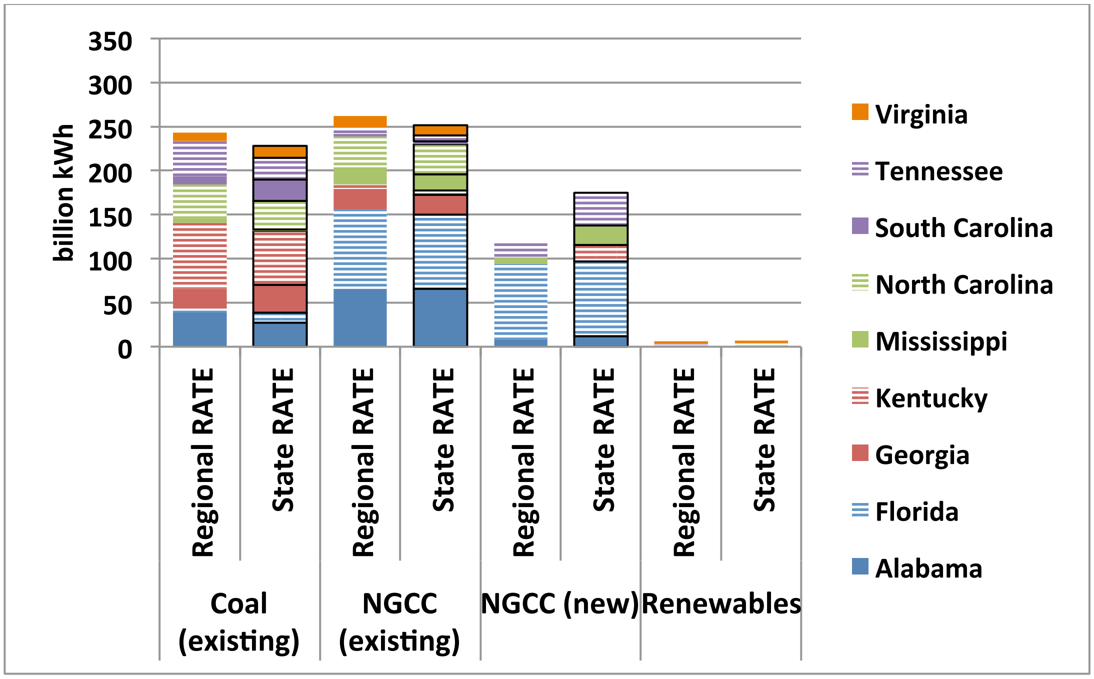


Figure 7 contrasts the regional rate-based CPP option with a regional mass-based alternative for existing units as laid out by the EPA (U.S. EPA 2014f).[12] This mass-based option assumes that the CPP covers only existing units, which tends to shift generation away from covered parts of the industry, and it removes extra incentives for new renewables and any existing gas units emitting at rates below those defined in the states' emissions rate targets. Under a mass-based approach, all emissions from existing affected fossil fuel-fired units are "taxed" in proportion to their total carbon content, as discussed in the Background section.

Perhaps counter-intuitively for a mass cap on CO_2 emissions, coal generation is significantly higher in the Southeast, both in 2020 and 2030, than it is under a regional rate-based approach. The reasons are several. First, the mass-based approach adds flexibility to the policy by allowing any declines in overall existing fossil fuel generation to help meet the policy goals; by contrast, any such declines, unless accompanied by improvements in system-wide emissions rates, do not help meet policy goals under a rate-based approach. Second, because a mass-based option does not incentivize use of existing NGCC units, the decline in these units' generation must be made up somewhere else. More generally, the additional flexibility of a mass-based approach lowers the per-ton cost of CO_2 emissions, as discussed below, meaning that operating coal units will be cheaper under this approach.

As in the rate-based scenario, accelerated construction of new NGCC units that are outside of the CPP policy is cost-effective in the mass-based scenario. How this pattern occurs across states depends on reactions in other types of generation. Alabama and Florida choose to expand new NGCC units and shut down existing ones under a mass-based approach. Kentucky, Mississippi, and Tennessee also move into NGCC generation, although with smaller declines in existing gas units. Other states that show larger declines in existing gas generation than in coal generation are more reliant on imports from states that have expanded into new NGCC units.

[12] Direct comparisons across options is difficult given that the options are not necessarily achieving the same levels of emissions.

Figure 7. Regional rate-based versus regional mass-based trading among existing units (2030)

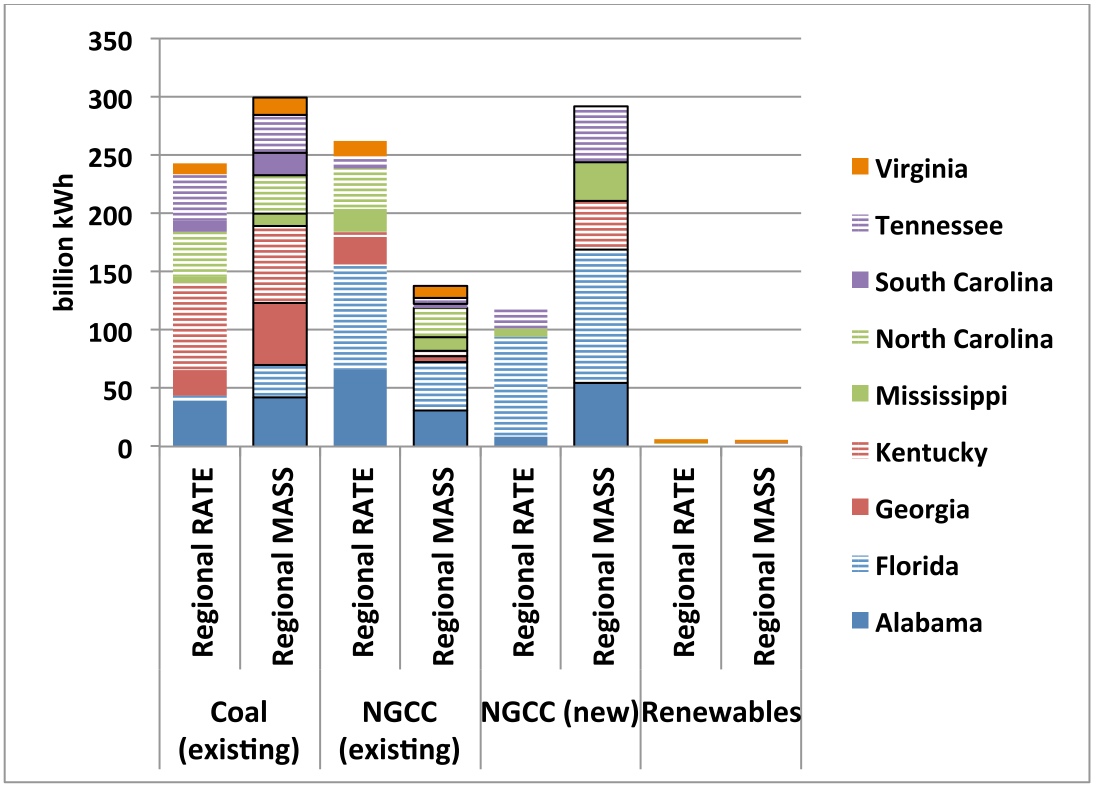
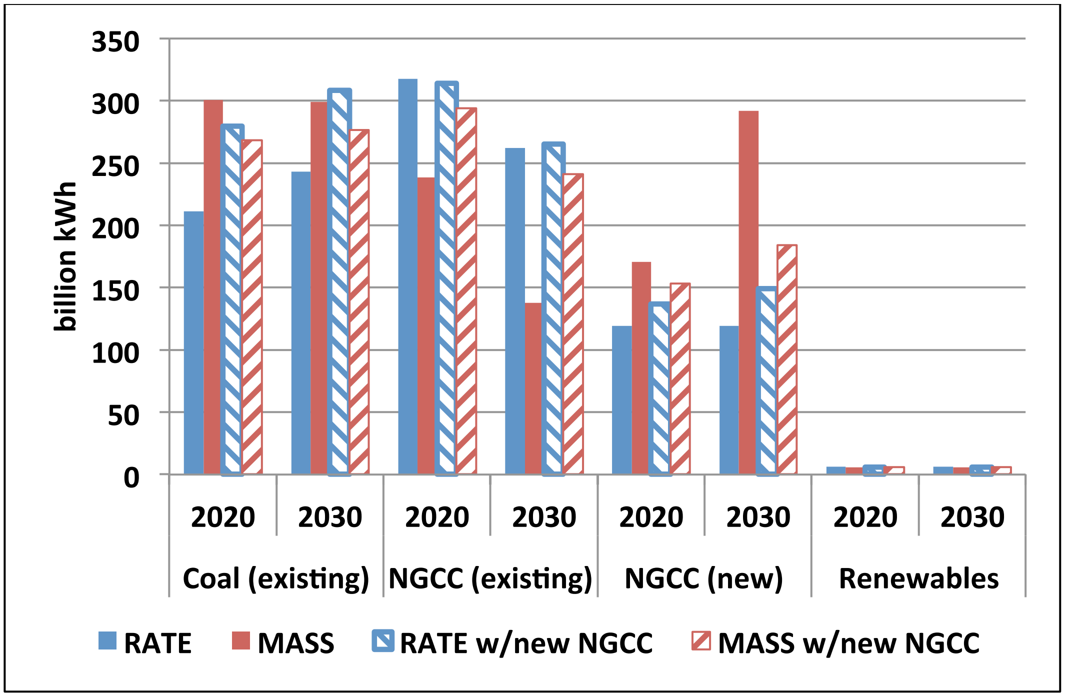


Figure 8 examines the implications of bringing new NGCC units under the CPP policy to avoid the situation in which only emissions from existing NGCC units are covered. Given that the emissions rate goal is not adjusted in setting policy targets in the "rate-based with new NGCC" model runs, and that the mass goals are taken from EPA calculations, the four alternatives are not directly comparable. However, in spite of definitional differences, the implications of rate and mass are similar when new NGCC units are brought into the policy. The largest differences occur for existing NGCC units that were previously disadvantaged under a mass-based approach. These units expand their generation to levels in the existing-unit rate-based approach that incentivized use of existing gas generation, removing the need for many of the new NGCC units required under the existing-unit mass-based approach.

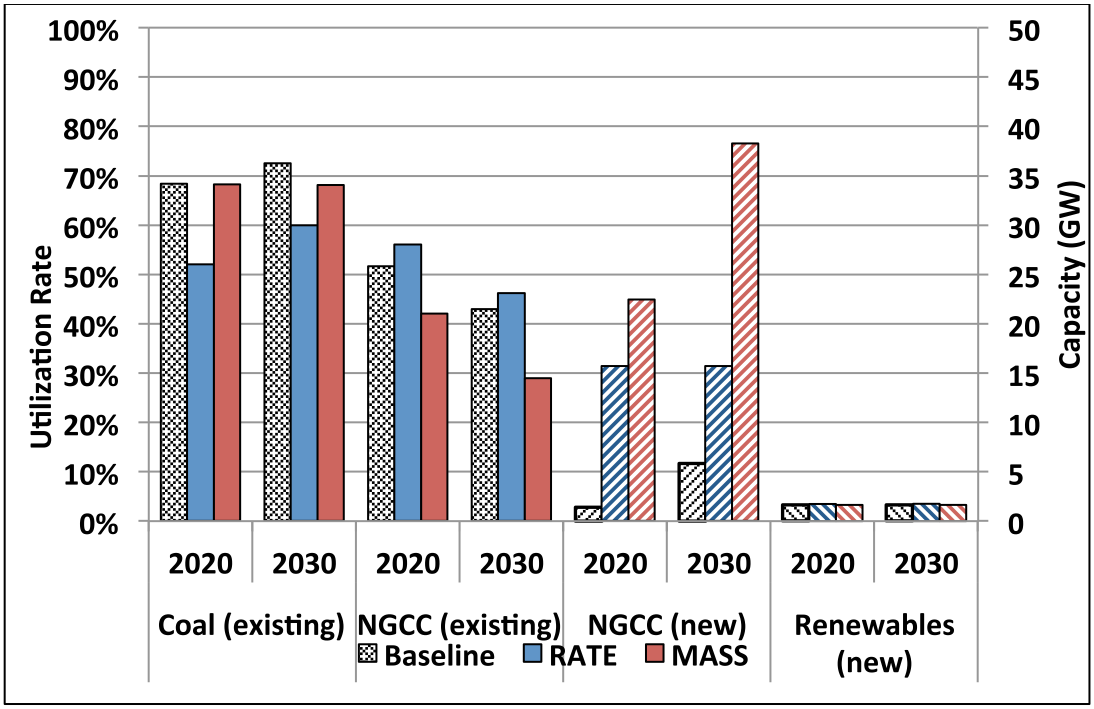
Figure 8. Regional rate-based versus mass-based trading with new NGCC units



Capacity and Utilization

Changes in generation cover many of the industry adjustments in response to the CPP, but it is also useful to examine some additional information. The left-hand side of Figure 9 shows changes in utilization rates for existing coal and NGCC units, while the right-hand side shows total cumulative construction of new units. The redispatch of coal into existing gas units can be clearly seen in the rate-based results, increasing utilization of the latter from 50% to 55% (this effect disappears under the mass-based option that does not incentivize this shift). Coal utilization rates are affected significantly in 2020 in the rate-based option. Construction of new NGCC units, measured in GW, differs significantly under the rate-based and mass-based options. The latter emphasizes new NGCC units to a much higher degree than the former (assuming these units are not covered by the CPP policy).

Figure 9. Existing-unit utilization rates and new capacity under regional trading



CO_2 Emissions

All policy scenarios reduce emissions relative to the baseline scenarios with and without energy efficiency as an investment option, but there are significant differences between policy scenarios. Because of its larger impacts on coal generation, the rate-based approach covering only existing units results in cumulative emissions reductions over the 2020–2050 time frame of around 31% relative to the baseline without the option to invest in energy efficiency measures. The similar mass-based approach covering existing generation provides CO_2 reductions of only 21% over the same period. At the emissions goals calculated by the EPA for a mass-based policy including new NGCC units, reductions of 26% are achieved—reductions closer to those under the rate-based option for existing units. Including new NGCC units in a rate-based system that maintains the original state emissions rate goals—the lowest-cost approach—also results in the lowest reduction in cumulative emissions at 18%. Regional compliance and individual state compliance emissions are nearly identical across the analyzed policy scenarios, with the exception of the "rate-based including new NGCC units" scenario.

Policy Costs

Policy costs encompass all costs associated with delivering electricity to meet grid demands in a particular state or region. Among these costs are those directly related to generating electricity in an area: capital costs of new construction or retrofits (these are typically annualized for cost-reporting purposes); fixed operations and maintenance (O&M) costs that represent annual maintenance expenditures; variable O&M costs, which vary with the level of generation; and fuel costs. Other types of costs such as carbon taxes or carbon allowance payments affect generation decisions in the model, but for cost-reporting purposes are simply a transfer among agents in the economy and do not represent a net cost to society as a whole. Therefore, they are not reported as part of a policy's national-level costs. It should be understood that DIEM minimizes policy costs for the nation as a whole over the entire time horizon in the model, which runs through the 30-year book life of new units installed in 2060. This long-term approach to cost minimization can lead to policy cost results in the short term that move counter to long-term trends.

From a state or regional perspective, additional costs and benefits are associated with importing or exporting electricity. Reported policy costs in this analysis assume electricity trade is valued at the wholesale electricity price prevailing in the exporting state or region during the load demand block in question. From a subnational viewpoint, costs and benefits can also be associated with importing or exporting CPP allowances to other states under the regional trading schemes. Neither of these types of state trade flows affect national cost minimization, but both need to be evaluated to determine local policy costs. Costs of energy efficiency measures paid by both utilities and consumers are also factored into the cost reporting.

As a general rule, flexibility in any form will always lower costs as utilities seek out cost-effective responses to the policy. The building blocks in the CPP provide several cost-lowering forms of flexibility: states can count energy efficiency measures and renewables toward compliance under the rate-based approaches, convert rate-based goals to mass-based goals, and, importantly, act in concert with other states to take advantage of low-cost reduction options across regions (locational or "where" flexibility). During the first decade of the policy, states can also smooth adjustments over time (temporal or "when" flexibility) as they move toward final emissions goals in 2030. Because DIEM operates with foresight, construction decisions will be optimal as utilities plan for future needs and take advantage of any available cost-saving flexibility, which will affect policy costs and investment patterns.

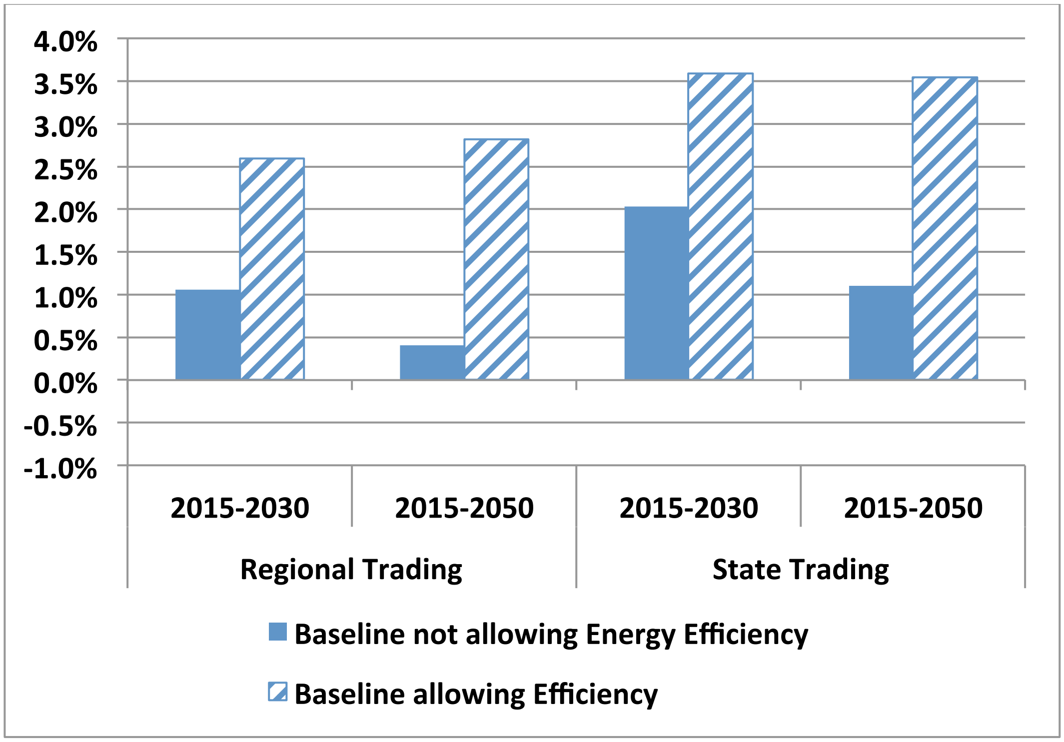
Before comparing policy costs across all the scenario alternatives, it is necessary to address the question of which elements are considered part of the baseline forecast in the model. As discussed above, the energy efficiency measures included in the modeling are a cost-effective alternative to electricity generation—whether or not the CPP policy is in place, leaving open the question of what are the appropriate baseline costs against which to measure policy costs. Allowing energy efficiency measures in the model's baseline means their apparent cost savings are not attributed to the policy, and thus these savings are not factored into the incremental costs between the baseline and the CPP policy.[13] As a result, estimated policy costs will be higher than they would be under the alternative assumption that the energy efficiency cost savings are brought about by the policy.

Figure 10 illustrates the magnitude of the energy efficiency attribution effect for regional and unilateral state compliance in a rate-based approach to the CPP. Although the modeling is optimizing costs over a longer time horizon, the results show changes in costs (in present value terms) either through the first decade of the policy or through 2050 because decisions may be based on shorter-term implications than those underlying the structure in the model. As the regional trading results show, in the near term the costs savings of energy efficiency measures almost offset all other policy costs, leaving a system-wide cost increase of 1.1% over the 2015–2030 period when compared to a baseline not including energy efficiency measures. Over a longer time horizon (through 2050), these savings offset even more CPP policy costs, which are 0.4% higher than costs in a baseline without energy efficiency measures. Adding the energy efficiency savings into the baseline ("Baseline Allowing Efficiency") results in a cost increase for CPP with regional trading of 2.6% through 2030 and 2.8% through 2050.

Similar impacts of accounting for efficiency in the baseline are seen for results from the CPP state-trading scenarios. The extra flexibility associated with regional trading lowers policy costs by 20%–28%, depending on the timeframe of interest, compared with the policy costs of states acting unilaterally.

[13] The same is also true of allowing coal-unit efficiency retrofits in the baseline, although this occurs less often in the baseline and has little effect on reported policy costs.

Figure 10. CPP rate-based policy costs with and without energy efficiency measures (present value over time periods shown)

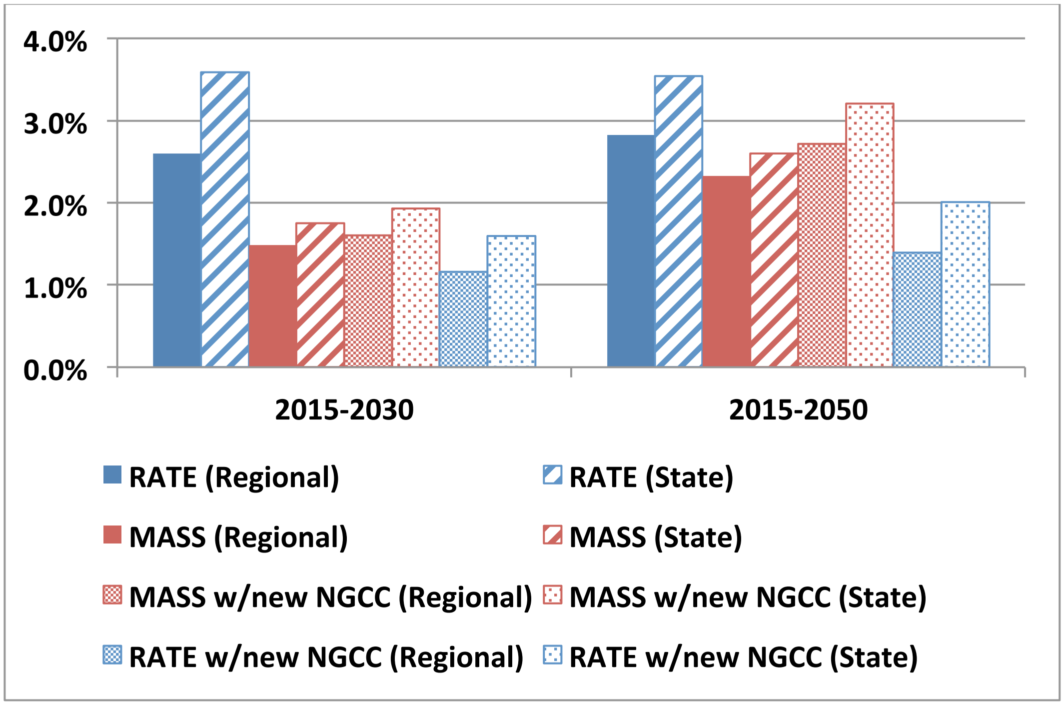


From this point forward, policy costs are presented compared to a baseline that allows energy efficiency in order to avoid the need to justify non-adoption of cost-saving measures in the model's baseline run; this logic implies higher policy costs than the alternative assumption.

Figure 11 compares the full range of scenario alternatives across rate and mass, and geographic scope, over the 2015–2030 and 2015–2050 time frames. Aside from the cost savings associated with a move from unilateral state action to regional trading, savings can be realized through a switch from a rate-based to a mass-based system. In the early years of the CPP, this switch results in a cost decrease of 40%–50%, although the savings from a mass-based approach are less dramatic when considered through 2050.

Including new NGCC units in a rate-based system lowers costs over either mass-based approach. Including these units in the regional rate-based option gives states significant flexibility to shift generation around the Southeast to take advantage of states that have emissions rate goals above those of new NGCC units (the assumption is that states keep their individual goals when entering regional trade agreements). Environmental impacts of this approach contrast with the cost results: including new NGCC units under a rate-based system raises emissions by 13% compared with emissions from a state-based rate system without new NGCC units and by 22% over those from a regional rate system without new NGCC units.

Figure 11. Southeast policy costs for all alternatives with energy efficiency measures included in the baseline (present value)



Wholesale Electricity Prices

The electricity component of DIEM used in this analysis focuses on wholesale electricity markets, rather than retail markets, and estimates wholesale electricity prices on the basis of the marginal costs of electricity generation.[14] How states implement the CPP can have significant impacts on these wholesale prices, although the way costs are passed through to retail customers in regulated markets may counteract some of these impacts.

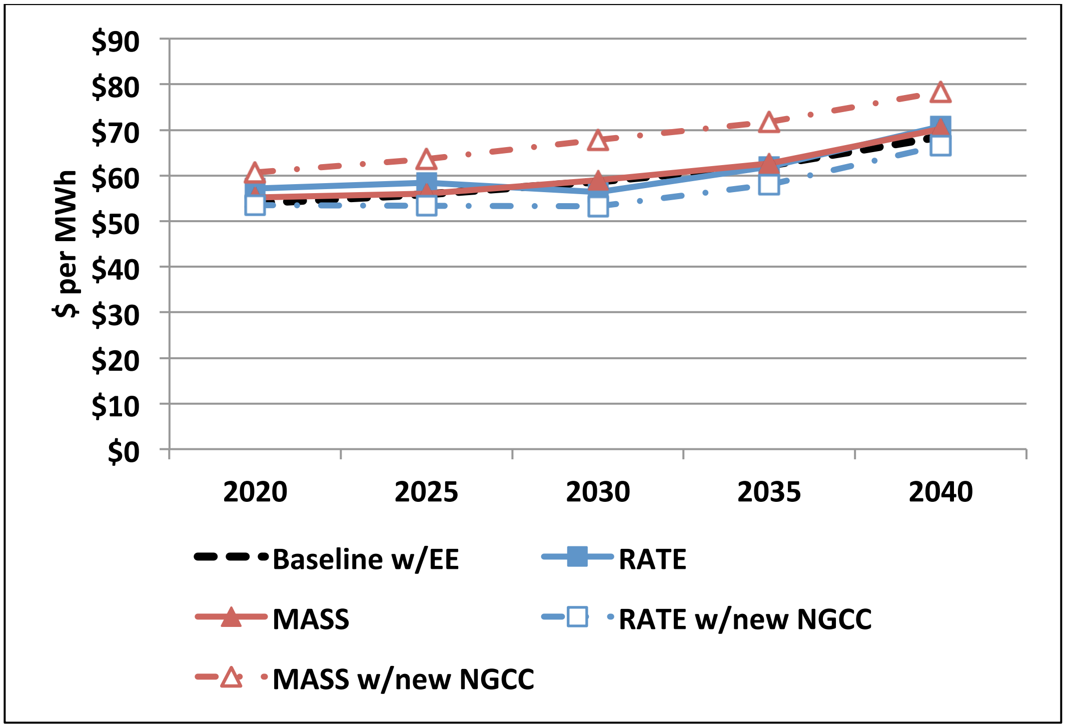
As discussed above, a rate-based approach works to "tax" generating units that emit at a rate above a state's goal and to "subsidize" units that emit at a rate below that goal. Conversely, a mass-based approach will "tax" all units in proportion to their emissions. The implications of these features can be seen in Figure 12, which compares the various scenario electricity prices against a baseline that includes energy efficiency measures, which will tend to eliminate the need for what would have been the highest-cost generating units, lowering the wholesale price in the baseline.

In the early years of the policy, both the rate-based and mass-based approaches covering existing fossil fuel-fired units lead to slight price increases, largely driven by the CPP's encouragement of a more rapid expansion of new NGCC units that are likely to be the high-cost price-setter in the markets. The price increase is higher under the rate-based approach (6% compared with 3% under the mass-based approach) because that approach necessitates larger initial adjustments than the more flexible mass-based option. By 2030, prices under the mass-based approach are still higher than those under the baseline, but prices under the rate-based approach have declined as the "subsidies" to existing gas units help lower operating costs

[14] Technically, wholesale prices are the shadow price on the demand constraint in the model and are available in each region for each time block in the load demand curve. These average prices are generation-weighted averages across regions and time blocks in the model.

for these high-cost units. A larger price decline is seen nationwide if a rate-based policy includes new NGCC units, which would be the price-setters in some markets. The most dramatic increase comes with a mass-based policy that includes new NGCC units because both existing and new NGCC units are taxed in proportion to their emissions, the costs of which are reflected in wholesale prices.

Figure 12. Southeast average wholesale electricity prices (regional trading)



Allowance Prices

The analysis examines how allowance prices associated with a regional and a unilateral state approach to the CPP vary across states in the Southeast. These prices, shown in $ per metric ton of CO_2, reflect the cost associated the highest-cost option taken in response to the policy, or the action on the margin that just allows a state or region to meet its emissions goals.

Allowance prices under the rate-based approach and those under the mass-based approach do not have the same meaning. In a rate-based approach, fossil fuel-fired units pay the price only on tons generated by units over states' emissions rate goal and receive this price for any tons generated under the emissions rate goal. Conversely, in a mass-based approach, all affected fossil fuel-fired units pay the allowance price for all tons of emissions, regardless of an individual unit's emissions rate. Across states within the Southeast region, variation in mitigation opportunities, as shown by differences in allowance prices, indicates the potential for gains from coordination.

The lightly shaded bars on the left-hand side of Figure 13 show allowance price results for the Southeast under the regional trading approach. The prices of $32/ton in 2020 and $27/ton in 2030 can be compared to the individual state allowance prices under the rate-based scenario in which states act alone rather than coordinate reductions. Several states have individual allowance prices below, or significantly below, that of the regional trading price, especially in 2020. These states can benefit from regional trading by engaging in additional emissions reduction actions in a cost-effective manner and then selling the resulting allowances to other states for more money than the cost of these actions. The high allowance prices for state-only approaches to the rate-based policy indicate that other states, most notably Kentucky, have very few intrastate options to achieve their emissions goal. These states can benefit from purchasing low-cost emissions reductions from other states under a regional trading option.

Figure 13. Allowance prices under rate-based trading over existing units

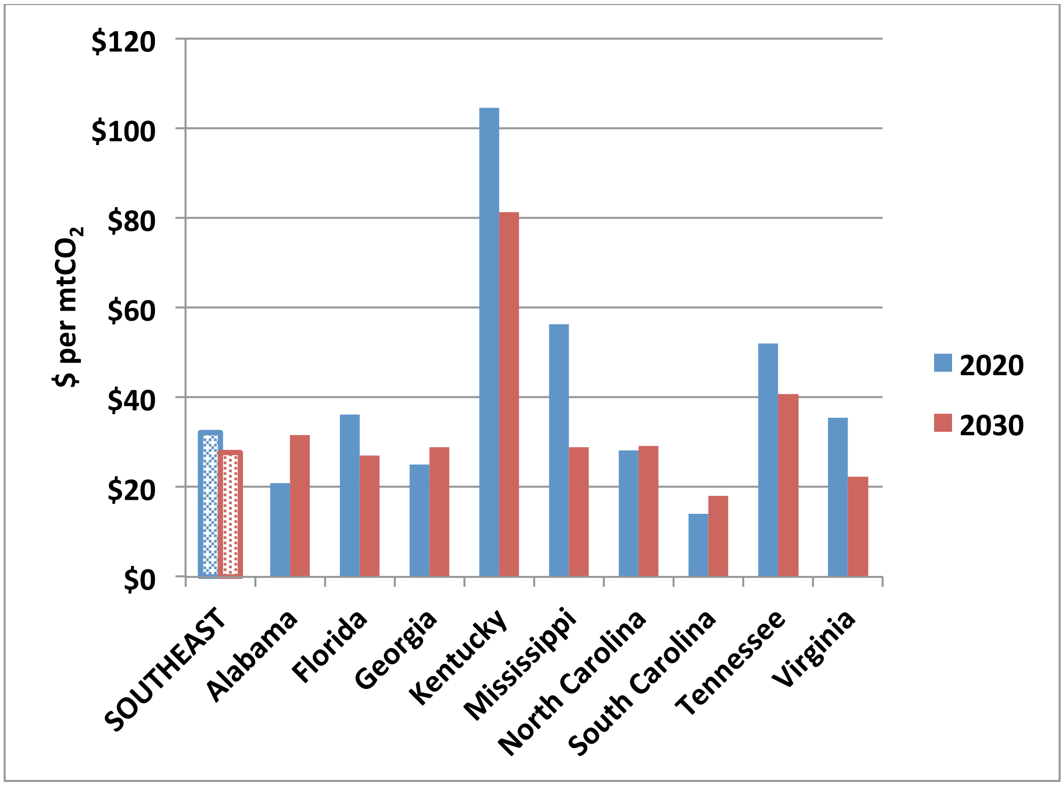
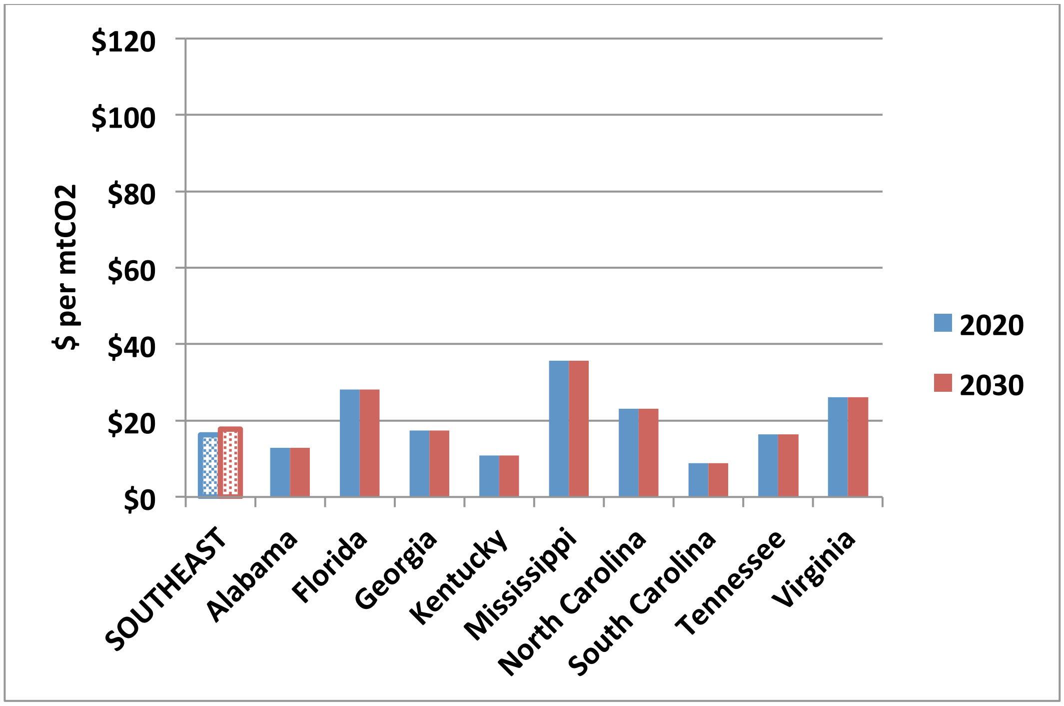


Figure 14 also compares regional allowance prices to state allowance prices—this time under a rate-based policy that includes new NGCC units. It shows, when compared with Figure 13, that inclusion of new gas units in the policy substantially lowers these prices. However, interpretation of this difference can be problematic. First, total emissions across the two approaches—rate over existing units and rate including new units—have very different impacts on regional CO_2 emissions, as was implied by the generation shifts in Figure 8. Covering only the existing units under the states' emissions rate goals results in emissions in 2030 of 373 $MMTCO_2$. Including new NGCC units in the rate-based policy (without adjusting emissions rate goals) results in emissions of 448 $MMTCO_2$ in 2030. However, covering both existing and new emissions sources does serve to smooth out the allowance price differences across states. Kentucky, which has few options such as renewables to respond to a rate-based policy over existing units, has among the lowest allowance prices if it can count emissions from new NGCC units against its final CPP emissions rate goal of 1,763 lb/MWh. Other high allowance-price states also benefit, but to a smaller degree. For example, Mississippi's goal of 692 lb/MWh is below the emissions rate of new NGCC units, so constructing and operating new NGCC units would not generate emissions credits to help meet the state's goal.

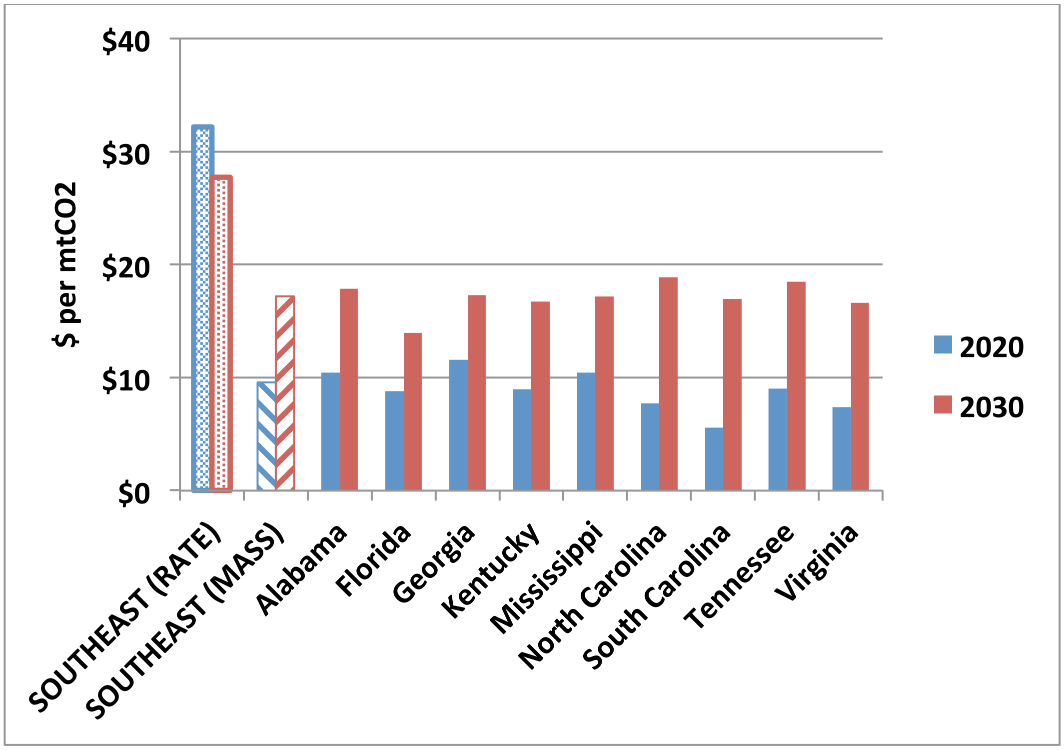
Figure 14. Allowance prices under rate-based trading including new NGCC units



Allowance prices under a mass-based approach tend to rise toward 2030 as the approach's added flexibility allows states to defer costs while keeping them initially low. For a regional trading policy, allowance prices start under \$10/ton in 2020 and rise to \$17/ton by 2030, when the CPP policy reaches its final goals. Although there is little variation between the regional trading price and the individual state allowance prices for a states-acting-alone approach, regional coordination still provides benefits under a mass-based option, as Figure 11 showed.

The revenue implications of the rate-based and the mass-based options are very different. Generally, in rate-based systems, the value of allowances is kept within the industry because units that generate at rates below the goal sell allowances directly to units generating above the goal. For mass-based systems, this is not necessarily the case because governments have the option to either auction or grandfather allowances associated with the policy. Potential revenues at these allowances prices are \$4.2–\$7.5 billion per year for the Southeast as a whole under a regional mass-based approach.

Figure 15. Allowance prices under mass-based trading compared with regional rate-based trading



State Policy Costs

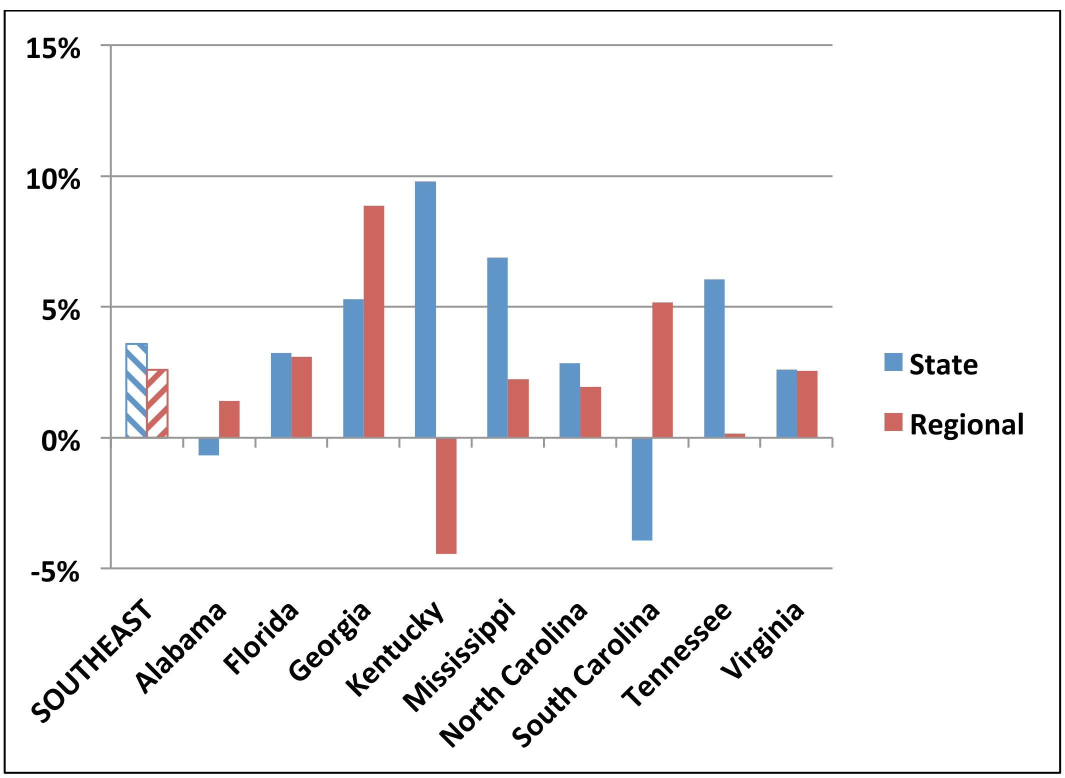
State-level costs of the CPP policy depend on a wide range of factors, among which are a state's emissions goals, existing generation fleet, and renewable generation construction capacity—and, importantly, how the model in question goes about determining state-level impacts. Attempting to estimate localized policy effects requires several model conditions such as data on existing and potential new units by state, the assignment of new generation in the model to specific states rather than to a broader region, forecasts of electricity demand at the state level, and specification of transmission constraints in a way that allows estimates of electricity trade among states. These data affect the cost-minimization decisions in the models as they supply electricity to the national grid. That said, models do not attempt to find the lowest-cost alternative for a specific state or group of states or to evaluate the possible outcomes of any political processes accompanying interstate or intra-utility/inter-utility coordination.

To the extent feasible, the version of DIEM-Electricity used for this analysis has been structured along the lines necessary to provide state-level impacts. However, as the geographic scope of the modeling results narrow to the state level, policy costs should be considered estimates because, among the other reasons, it is necessary to assign a dollar value to changes in interstate electricity trade. Electricity dispatch models focus on minimizing total national costs of generation over time subject to meeting electricity demands and other system constraints, including transmission constraints. Accordingly, models are concerned with physical flows of electricity among regions, not the dollar value of inter-state or inter-regional trade. To evaluate trade flows, the above-discussed wholesale prices determined by the marginal-cost generators in a state are applied to electricity trade by demand load block to turn electricity flows into dollar flows. Although this process can approximate how markets tend to work in the real world, it raises the possibility that some states can appear better off if they are selling electricity at a marginal cost that is higher than the costs of generating that electricity.

Figure 16 shows that although allowance prices (i.e., marginal costs of meeting the policy goals) are relatively uniform across regions, especially for a mass-based policy, overall policy costs can vary substantially. The lightly shaded bars on the far left show average costs across the Southeast for the state-trading and regional-trading approaches to a rate-based policy (from Figure 11). Within these averages, effects on individual states of a state-acting-alone policy (in blue) are generally higher than those for regional coordination (in red). However, this result is not guaranteed to hold for all states, given the methodology used to estimate cost impacts and the fact that the model is not attempting to evaluate how political processes may work to distribute the gains from trade achieved through regional trading.

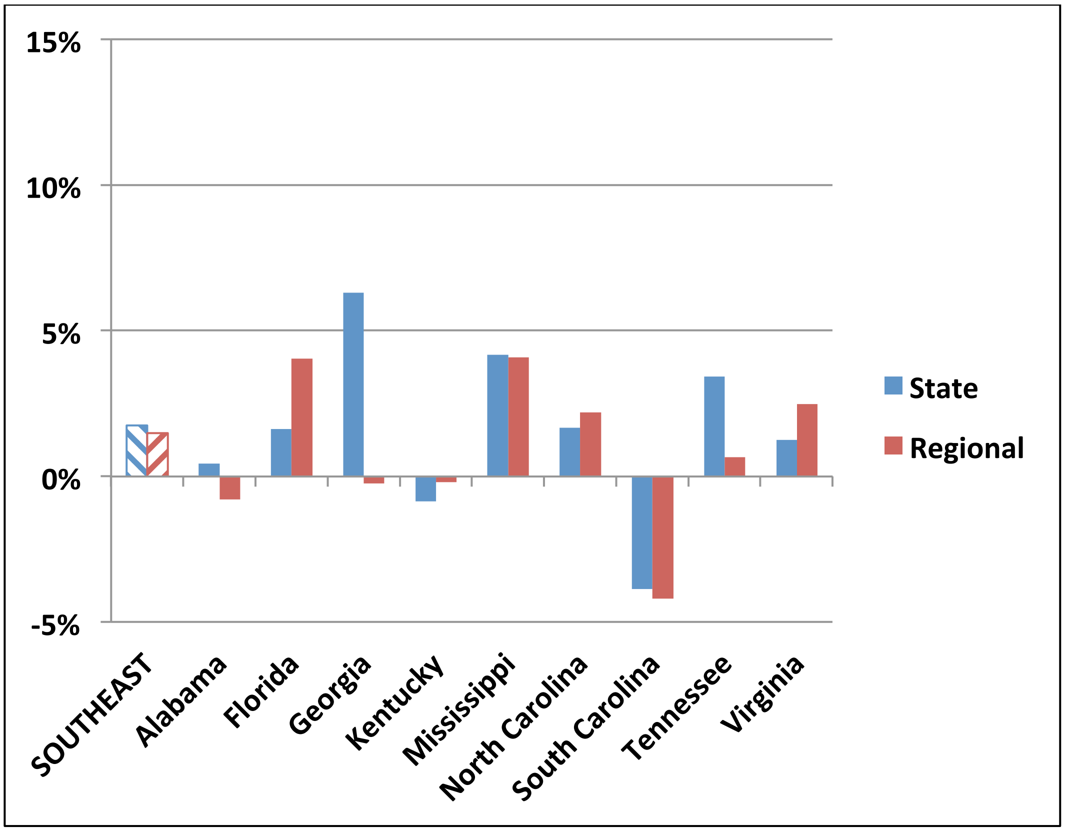
Under a unilateral approach, Kentucky, for example, experiences significant costs because it has few intrastate methods to meet policy goals (assuming those goals are applied only to existing units and not to new NGCC units). Under a regional approach, however, Kentucky has policy costs below its baseline costs because it can quickly shift from coal generation to new NGCC generation outside of the CPP policy and can then benefit from selling this cleaner electricity to surrounding states. Other states such as Alabama and South Carolina appear better off under intrastate trading than regional trading due to how their generation patterns and trade flows change (see Figure 6 for generation changes). This result does not imply, however, that they are better off acting alone while the rest of the region's states coordinate their actions because policy impacts are predicated on each state pursuing the same policy approach in each scenario run. Were particular states to drop out of regionally coordinated efforts, the policy impacts for all states in the region would be altered. Moreover, this analysis' present value of costs through 2030 does not always follow costs from the longer-term cost optimization in the model.

Figure 16. State policy costs under rate-based trading over existing units (present value 2015–2030)



In Figure 17, the lightly shaded bars again show average regional impacts with state trading and with regional trading of allowances—this time for a mass-based approach to the CPP. Overall, the lower policy costs of a mass-based system (compared to the costs of a rate-based system, as shown in Figure 16) hold across many states within the Southeast, regardless of type of trading system. Most states—and particularly Kentucky and other states that have difficulty meeting a rate-based goal if acting unilaterally are better off with regional trading of mass-based allowances, but individual state impacts are dependent on the specific level of their mass emissions caps. Again, some states can benefit from the combination of their allowance allocation under the policy and their potential capacity to generate and sell excess electricity to surrounding states.

Figure 17. State policy costs under mass-based trading over existing units (present value 2015–2030)



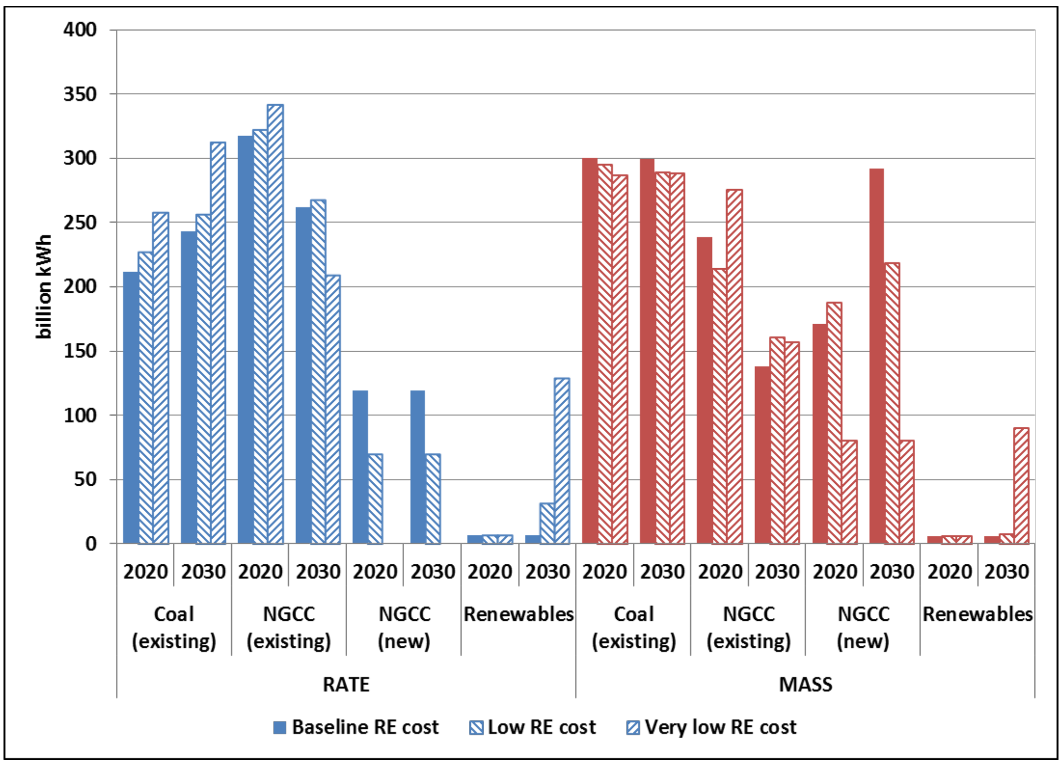
Sensitivity Analyses

How generation responds to a policy in a linear-programming model such as DIEM can be contingent on assumptions about future conditions in electricity markets. For the CPP, several critical assumptions are worth exploring to see how alternative possibilities may affect generation choices, namely, capital costs of renewables, the availability of energy efficiency measures, and future natural gas prices. This analysis's exploration of these three cases for both rate-based and mass-based approaches to the CPP focuses on the regional trading option.

Construction of new renewables in electricity dispatch models is highly dependent on expected capital costs because these are the largest component of renewables' total cost. Renewables are favored under both rate-based and mass-based policies, although as discussed above, there are additional incentives for renewables built into the calculation of the CPP's rate-based goals. In Figure 18, the dark-shaded bars show the same generation choices in Figure 8. The lighter-shaded bars show generation for two sensitivity cases: "Low RE cost" in which it is assumed that today's capital costs for renewables are one-third lower than the AEO assumptions (U.S. EIA 2014b) that represent baseline renewables (RE) costs, and "Very low RE cost" in which it is assumed that today's capital costs are one-half lower than the AEO assumptions. For both cases, it is also assumed that capital costs decline more quickly than in the model's baseline, based on the more optimistic option in Blanford et al. (2014). These assumptions have wind costs decreasing by 1.5% per year instead of 0.9%, and solar costs decreasing by 3.1% per year instead of 2.4%.

Under rate-based approach, the "Low RE cost" and "Very low RE cost" results indicate some increase in renewable generation by 2030 if capital costs are 33% lower than in the AEO assumptions and a significant increase if costs are 50% lower.[15] These increases have two effects: first, allowing more coal units to run by offsetting their emissions in the emissions rate calculations, and second, reducing much (or all) of the need for new NGCC generation. In the mass-based results, there are also more renewables for the larger decrease in costs, although they are mainly competing directly with new NGCC units on a cost basis and preventing the shift into new NGCC generation that occurred in this case.

Figure 18. Alternative renewables costs

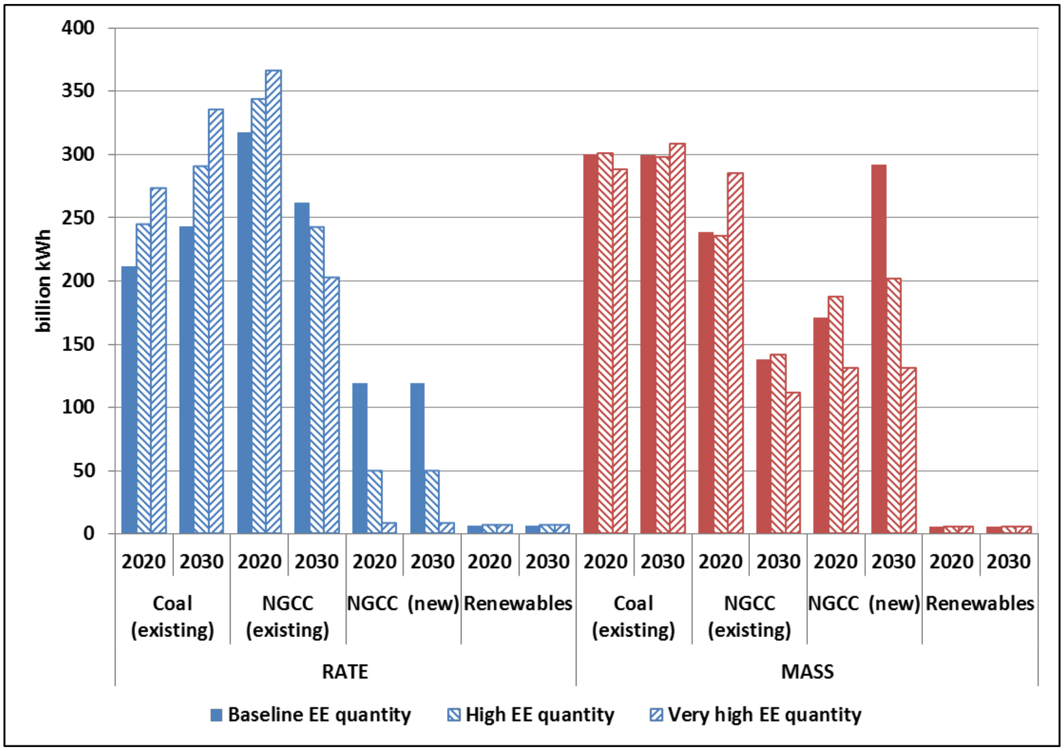


The next assumption of interest is the availability of energy efficiency. It is presumed here, with no attempt to justify assumptions about a specific level, that the quantity of available energy efficiency measures is either 50% ("High") or 100% ("Very high") more than that given by the baseline energy efficiency numbers from the EPA (U.S. EPA 2014d), but at the same price. In the rate-based scenario, extra energy efficiency measures (like renewables, as depicted in Figure 18) allow existing coal units to run at a higher level. At this quantity they also offset most of the need for new NGCC units and many of

[15] Specifically, the increase is in utility-scale solar photovoltaic (PV) given that wind resources are limited in the Southeast. No adjustments are made to solar PV costs to account for any potential need for fossil fuel-fired backup generation if solar or wind generation becomes a substantial share of total generation.

the new renewables. Under a mass-based system, greater energy efficiency does not provide much assistance to coal units, but the resulting lowering of electricity demands mean that not many new NGCC units need to be constructed.

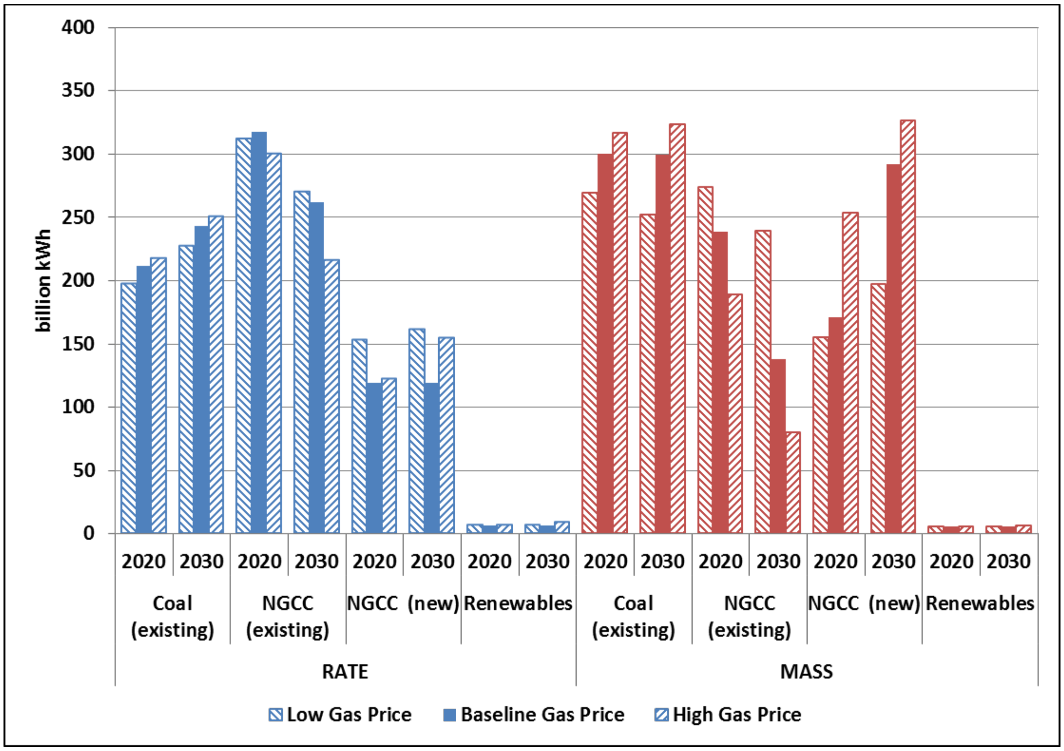
Figure 19. Alternative energy efficiency quantities



Finally, natural gas prices are an important determinant of how the electricity sector responds to demand levels and any existing or new policies. To explore the implications for the CPP, alternative gas prices are applied in DIEM on the basis of the high-resource and low-resource side cases in the AEO (U.S. EIA 2014a). These cases define gas prices that are approximately 25%–30% higher or lower than the expected baseline prices in the model.

Figure 20 shows that price changes have somewhat different effects for the rate-based scenario covering existing units than for the mass-based scenario covering existing units. In the rate-based scenario, low gas prices benefit new NGCC generation as well as existing NGCC units that are generally less efficient (i.e., have higher heat rates measured in Btus of gas per kilowatt-hour of electricity output) than the new NGCC units. This extra gas generation reduces the need for electricity from coal. Higher gas prices hurt existing, less-efficient NGCC units, increasing generation from new NGCC units to meet electricity demands. Mass-based scenarios show larger responses to natural gas prices sensitivities: low gas prices increase existing NGCC generation at the expense of coal and new NGCC units, and high gas prices increase coal and new NGCC units at the expense of existing NGCC generation.

Figure 20. Alternative natural gas prices



Conclusions

Generation in the Southeast region is in the midst of a dramatic transition, having shifted over the last decade from reliance on coal to reliance on natural gas. The CPP policy encourages additional natural gas generation while incentivizing significant declines in electricity from coal-fired plants, though with notable differences between rate- and mass-based compliance approaches covering only existing units; rate-based approaches lead to a steeper drop in coal generation, especially in 2020. If the capital costs of renewables play out as anticipated by the EIA (U.S. EIA 2014b), there are likely to be few cost-effective renewable options in the region, which leads to large declines in coal generation in the rate-based approach and to smaller declines in the mass-based approach. However, as the sensitivity analyses demonstrate, rate-based coal generation partially recovers if renewables costs proceed along more optimistic trajectories.

Across the four possible approaches to covering existing sources under the CPP, a rank ordering of policy costs from lowest to highest is as follows:

1) Mass-based with regional trading
2) Mass-based with state trading
3) Rate-based with regional trading
4) Rate-based with state trading

Each of these four options can result in significant shifts into new NGCC units because these units remain outside the policy definition. Attempting to regulate these units under the CPP results in mixed messages regarding policy costs, Figure 11 showed. A mass-based system including new NGCC units appears to entail greater policy costs than a rate-based system including these units, particularly through 2050. The emissions reduction achieved by these systems varies considerably. Comparing costs for significantly different emissions outcomes is difficult given that the goal of the Clean Power Plan is to reduce CO_2 emissions.

Across states in the Southeast region, CPP policy costs are relatively dissimilar, a perhaps not surprising result given that current generation varies widely across these states. Although the final outcome of policy costs is likely to be the result of a political process, the model findings indicate less state-to-state variation with mass-based approaches, which have smaller impacts than rate-based approaches. The same broad result holds for the allowance prices that represent variation in marginal policy costs across states. As with the implications of mass versus rate, the modeling makes clear that regional coordination in meeting policy goals is likely to lead to substantial cost savings, whether measured in terms of marginal or of total policy costs.

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