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Federal Policies for Renewable Electricity

Impacts and Interactions

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Abstract

Three types of policies that are prominent in the federal debate over addressing greenhouse gas emissions in the United States are a cap-and-trade program (CTP) on emissions, a renewable portfolio standard (RPS) for electricity production, and tax credits for renewable electricity producers. Each of these policies would have different consequences, and combinations of these policies could induce interactions yielding a whole that is not the sum of its parts. This paper utilizes the Haiku electricity market model to evaluate the economic and technology outcomes, climate benefits, and cost-effectiveness of three such policies and all possible combinations of the policies. A central finding is that the carbon dioxide (CO_2) emissions reductions from CTP can be significantly greater than those from the other policies, even for similar levels of renewable electricity production, since of the three policies, CTP is the only one that distinguishes electricity generated by coal and natural gas. It follows that CTP is the most cost-effective among these approaches at reducing CO_2 emissions. An alternative compliance payment mechanism in an RPS program could substantially affect renewables penetration, and the electricity price effects of the policies hinge partly on the regulatory structure of electricity markets, which varies across the country.

Key Words: renewable portfolio standard, renewable energy credits, cap-and-trade, climate policy

JEL Classification Numbers: Q42, Q54, Q58

Table of Contents

Introduction **1**

Policy Background and Literature Review **2**

- Greenhouse Gas Policies 2
- Renewables Policies 3
- Literature Review 5

Model Description **7**

Scenario Descriptions **10**

- Baseline Scenario (BL) 10
- Policy Scenarios 11
  - Cap-and-Trade Program (CTP) 12
  - Renewable Portfolio Standard (RPS) 12
  - Tax Credits (TC) 13
  - Policy Combinations 13
  - Nuclear Cost Sensitivity 13

Results **13**

- Renewables Penetration and REC Prices 14
- Generation Mix 17
- Electricity Prices 23
- CO_2 Emissions and Allowance Prices 29
- Policy Evaluation 31

Conclusions **34**

References **37**

Appendix **39**

Federal Policies for Renewable Electricity: Impacts and Interactions

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Introduction

The struggle in the United States to find politically palatable policies to address the issue of global climate change has engendered an array of proposals in the U.S. Congress. These proposals range from establishing binding caps on greenhouse gas emissions to providing incentives for research, development, and deployment of clean energy technologies. Similar policies have been advanced and in many cases adopted at the state level. All of these policies aim to accelerate the expansion of renewable electricity generation and reduce greenhouse gas emissions. At the state level, the most common policies to promote renewables that have been adopted are renewable portfolio standards (RPS) and tax credits for renewable electricity production. At the federal level, the government offers a substantial suite of tax credits and loan guarantees for renewables and continues to debate further legislation that could extend the current policies, create a federal RPS, and/or institute a federal cap-and-trade program for carbon emissions. The efficacy and cost-effectiveness of these different policy approaches depends on the combination of policies that are adopted, the particulars of the policy design, and the goals that the policies seek to achieve.

This paper examines the cost-effectiveness of various renewable energy and climate policies, individually and combined, at accelerating deployment of renewable generation technologies and reducing greenhouse gas emissions. The policies examined are a federal cap-and-trade program, a federal RPS, and an extension of federal tax credits for qualifying renewable energy sources. A partial equilibrium electricity market simulation model is used to analyze how these policies affect the generation mix, electricity prices and consumption, and greenhouse gas emissions at both the national and regional levels. The model provides information on carbon dioxide (CO_2) emissions effects both within the electricity sector and, for cap-and-trade policies, for the broader economy. The analysis finds that the CO_2 emissions

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reductions under cap-and-trade can be an order of magnitude greater than those of the other policies examined, even for similar levels of renewable electricity production, and the benefits can be achieved more cost-effectively. An RPS program with a sufficiently high target does increase renewable generation; however, alternative compliance payment mechanisms can significantly diminish the effect of the policy while generating significant government revenue and potentially creating the opportunity for policy combinations to increase the penetration of renewables. The cap-and-trade policy modeled here tends to raise electricity prices while the tax credit policy tends to lower it in all regions, but the effect of the RPS on electricity prices varies regionally, depending on how electricity markets are regulated in each region.

The paper is organized as follows. The first section provides an overview of the current and proposed policies in the United States to promote renewables and restrict greenhouse gas emissions and reviews the existing literature. The next two sections describe the Haiku electricity market model that is used for the analysis and the different policy scenarios that are analyzed. The last two sections present the results and some conclusions from the analysis.

Policy Background and Literature Review

Over the past several years there have been many efforts to introduce incentive-based policies to limit emissions of greenhouse gases and increase use of renewable energy in the United States. Some proposed climate legislation has included provisions that directly promote greater use of renewables. Several stand-alone policies to promote electricity generation from renewable sources and other clean energy sources have also been introduced in Congress. In general, policies to promote renewables have been more successful at winning legislative approval, particularly at the state level, than policies that seek to limit emissions. In this section we briefly discuss each type of policy and its current status in the United States.

Greenhouse Gas Policies

The majority of proposals that use an incentive-based approach to reduce emissions of greenhouse gases take the form of cap-and-trade policy rather than pricing emissions directly through a fee or tax mechanism. Several cap-and-trade bills have been introduced in recent sessions of Congress. The bill that progressed furthest in the legislative process is the Waxman-Markey Bill (H.R. 2454), which passed the U.S. House of Representatives on June 26, 2009. In addition to capping emissions, this bill also included a federal renewables portfolio standard of 20 percent by 2020 and other provisions to promote clean technology, such as research and development funding for carbon capture. Since this action by the House, several other bills have been proposed in the Senate, but none have passed out of committee or been considered for a floor vote.

Despite the lack of progress on climate legislation at the federal level, several states and groups of states have implemented or are on their way to implementing cap-and-trade programs for greenhouse gas emissions. The Regional Greenhouse Gas Initiative (RGGI), which is a cap-and-trade program covering CO_2 emissions from the electricity sector in the Northeast, is the only U.S. program that has already been implemented, having started at the beginning of 2009. California has passed a law, AB 32, that would regulate CO_2 emissions by cap-and-trade, but it has yet to take effect and the implementation details are not yet resolved. California is also one of seven western states and four Canadian provinces that have banded together to form the Western Climate Initiative, which is developing its own regional cap-and-trade program. The governors of several midwestern states and the premiers of two Canadian provinces have signed on to the Midwestern Greenhouse Gas Accord, which is in the process of developing a policy to limit emissions. None of these policies include any direct incentives for renewables, although some RGGI states are using some of the CO_2 allowance revenues generated at auction to fund renewables R&D and deployment projects.

Renewables Policies

As of this writing, the main federal incentive-based policy to promote renewables is a suite of production and investment tax credits. For new renewable generators brought online between 2009 and the end of 2013 (2012 for wind), the production tax credit policy provides a 2.1-cent tax credit for every kilowatt-hour generated using wind, geothermal, and closed-loop biomass, and a 1.1-cent tax credit per kWh for landfill gas, other forms of biomass, and hydrokinetic and wave energy. The tax credit applies to all generation during the first 10 years of operation.[1] The first renewables production tax credit passed in 1992; it has lapsed three times since then but always been reinstated, albeit at modified levels and with some changes in eligibility over time. The intermittency of this policy has led to large yearly fluctuations in the installation of wind turbines as project developers race to beat the policy expiration or see a greater option value in waiting to develop new projects when the policy has lapsed (Wiser 2008). The American Recovery and Reinvestment Act of 2009 extended the deadlines on the production tax credit and also allowed investors to choose among the production tax credit, an investment

[1] For more on the renewables tax credits legislation, see Bolinger et al. (2009).

tax credit equal to 30 percent of installation costs, and a cash grant equivalent in value to the investment tax credit. Although the production tax credit does not apply to solar, Congress recently extended a 30 percent investment tax credit for commercial and residential solar installations through 2016.

At the state level, the most common type of policy for renewables is an RPS, which requires that a minimum amount of electricity generated or sold in the state be produced using eligible renewable technologies. As of September 2010, 29 states plus the District of Columbia had implemented RPS policies.[2] These standards vary substantially across the states in terms of their timetables, targets, and eligible renewables. Sixteen states have special provisions for solar or other forms of distributed generation. In states where credit trading is allowed, the RPS generally works by creating an additional commodity, a renewable energy credit (REC), for every kWh of eligible renewable electricity generated. The RECs created by renewable generation may then be sold to utilities that generate electricity by other means and are required to hold some predefined number of RECs for every megawatt-hour of power they sell. Some states cap the price of RECs by allowing generators to purchase unlimited RECs at a fixed price called an alternative compliance payment. Thus, the effect of an RPS on the economics of renewable generation depends on the specific features of the policy design.

In addition to or, in some cases, instead of the RPS, the states have pursued several other types of policies to promote renewable sources of electricity. As of September 2010, 43 states plus the District of Columbia had net-metering policies that require utilities to allow end-use customers to sell back to the electricity grid at the avoided cost of generation, essentially allowing the electric meter to run backward when a distributed renewable generator produces more electricity than required for its own consumption. Some states also have their own tax incentives for renewables as well as rebate and loan programs. Utilities and other power suppliers in 47 states also have voluntary green power purchase programs for consumers (Bird et al. 2009b). Following the lead of 18 European countries (NRC 2009), a few U.S. states (including California, Vermont, and Washington) have adopted feed-in tariffs, which specify a fixed wholesale price for renewable generation. The specifics vary widely across jurisdictions, but the policies are usually designed with higher-cost technologies, like solar photovoltaics, having higher tariffs than lower-cost technologies, such as wind. Feed-in tariffs are typically

[2] See http://www.dsireusa.org (accessed September 13, 2010) for more information about federal and state policies to promote renewables.

guaranteed for a certain amount of time and thus lower the risk borne by investors in renewable generation capacity. However, over-generous incentives could stimulate investment to levels that have undesirable effects. Spain recently had to reduce the size and structure of its feed-in tariff quite dramatically to keep from bankrupting the program (Voosen 2009; Cory et al. 2009).

Literature Review

The relative effectiveness and costs of different policies to promote renewables and to cap CO_2 emissions have been the subject of much modeling analysis in recent years. The National Renewable Energy Laboratory (NREL) has published several reports that use either the Regional Energy Deployment System (ReEDS) model or its predecessor, the Wind Energy Deployment System (WinDS) model, to analyze the expansion of renewable electricity generation throughout the United States in response to types and levels of policy. Sullivan et al. (2009) used the ReEDS model to examine three renewable electricity standard (RES) policies recently under consideration by Congress: a 20 percent RES by 2021 with energy efficiency assumed to account for up to 25 percent of the RES (proposed by Rep. Bingaman), a 25 percent RES by 2025 (proposed by Rep. Markey), and a 25 percent RES by 2025 that is assumed to be reduced by 20 percent if state energy efficiency programs are shown to yield electricity savings of 15 percent by 2020 (proposed by Reps. Waxman and Markey in an early draft of their legislation). Several of these policies exclude small utilities from the requirement, and this exclusion, combined with the inclusion of electricity savings from efficiency gains, would mean, according to the study, that the effective renewables share would be between 3 and 8 percentage points lower than the nominal goal stated in the policy. Moreover, under the Bingaman and Waxman-Markey policies, the study finds that renewable generation and capacity would actually fall in 2030, compared with the baseline scenario, because total load is lower as a result of efficiency and the substitution of distributed PV, which gets triple credits under the REC policy. They also find that these policies can reduce or, in some cases, slightly increase electricity prices, and that for the Bingaman policy the REC price would never rise above zero, indicating that the policy would be nonbinding.

Researchers at NREL also participated in a study that sought to characterize the changes to the electricity sector needed to achieve 20 percent of total generation from wind by 2030 (U.S. DOE 2008). This study found that, based on the projection of 5,800 terawatt-hours (TWh) of electricity consumption from the Annual Energy Outlook (AEO) 2007 of the Energy Information Administration (EIA), 305 gigawatts (GW) of wind energy capacity would be required to meet 20 percent of this load, with annual capacity growth of more than 16 GW after 2018. This is a major increase over both the 11.6 GW of total installed wind capacity at the time this report was written and the approximately 19 GW of total installed wind capacity by 2030 projected in AEO 2007. In another study focused on current policy, Bird et al. (2009a) look at the national and regional correspondence between renewables capacity growth and increased demand for renewables from state-level RPS policies. They find that overall, there should be sufficient renewables capacity nationwide to meet aggregate demand for renewable generation across all the state policies; however, in some states there may not be sufficient capacity locally, if econometric forecasts of new capacity likely to come on line are borne out.

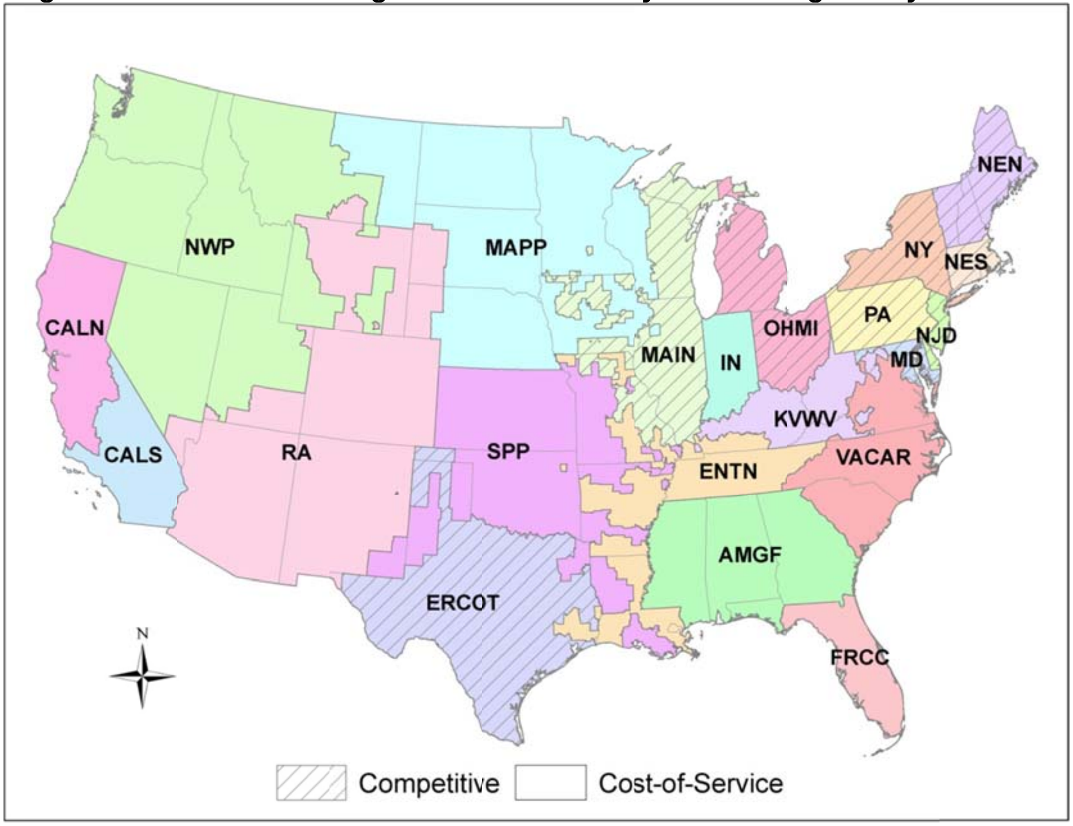
Bird et al. (2010) used the ReEDS model to analyze different levels of RPS policies and cap-and-trade policies and study the effects of each policy and of the various policy combinations on renewable generation, electricity supply, electricity prices, and CO_2 emissions. The objectives of that study are much like those of this study, but the modeling platforms and some assumptions about how the policies would be implemented are different. One similarity is that the standard cap-and-trade policy that they analyze is based on the H.R. 2454 emissions caps and very similar to the policy analyzed in this paper. The RPS scenarios that they model include some assumed levels of electricity demand reductions resulting from energy efficiency programs (enacted coincidentally with the renewable policies). They find that a 25 percent RPS policy (with associated efficiency savings) results in similar levels of CO_2 emissions reductions and similar electricity prices as their standard cap-and-trade case through 2020, when the two policies start to diverge and the cap-and-trade policy yields more emission reductions and higher prices than the 25 percent RPS. They find that cap-and-trade would lead to greater use of renewables than in a reference case in the near term, but layering an RPS on top of cap-and-trade would lead to even greater use of renewables without much of an effect on electricity price. They also find that adding an RPS, again combined with electricity consumption reductions due to efficiency gains, to a cap-and-trade policy would reduce CO_2 allowance prices.

Economists have also brought other analytical approaches to bear on this question of climate and renewable policy interactions. In a recent review piece, Fischer and Preonas (2010) look at how different policy mechanisms interact and what types of justifications are required for adopting multiple policies. They focus on the combination of a cap-and-trade policy for CO_2 and an RPS with REC trading for renewables. They find that understanding the existing policy landscape and existing market failures is important for assessing the effectiveness and economic efficiency of additional policies. Earlier work has shown that RPS policies tend to be more effective than price-based policies, like feed-in tariffs, at promoting investment in renewable generation capacity, and cap-and-trade policies (or emissions taxes) are more effective than quantity (RPS) or price-based (feed-in tariffs) policies at reducing CO_2 emissions. They also find that policies like an RPS that tax fossil generation and simultaneously lower the emissions allowance price under cap-and-trade tend to lower generation by natural gas disproportionately relative to coal. On the other hand, if an RPS policy is in place and a policy like cap-and-trade that taxes fossil output is added, it tends to reduce total generation and therefore reduce the quantity of renewables required to satisfy the RPS.

Model Description

The Haiku electricity market model (see Paul et al. 2009 for complete model documentation) is used in this study to evaluate the various policy scenarios that will be introduced in the following section. Haiku is a deterministic, highly parameterized simulation model that calculates information similar to the Electricity Market Module of the National Energy Modeling System (NEMS) used by the EIA and the Integrated Planning Model developed by ICF Consulting and used by the U.S. Environmental Protection Agency (EPA).

Figure 1. Haiku Market Regions and Electricity Market Regulatory Structure



Haiku simulates equilibria in regional electricity markets and interregional electricity trade with an integrated algorithm for emissions control technology choices for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury. Emissions of CO_2 are also tracked, but without any endogenous choice for emissions abatement technology. The composition of electricity supply is calculated for an intertemporally consistent capacity planning equilibrium that is coupled with a system operation equilibrium over geographically linked electricity markets; the model solves for 21 regional markets covering the 48 contiguous U.S. states. Each region is classified by its method for determining the prices of electricity generation and reserve services as either market-based competition or cost-of-service regulation. Figure 1 shows the regions and pricing regimes. Electricity markets are assumed to maintain their current regulatory status throughout the modeling horizon; that is, regions that have already moved to competitive pricing continue that practice, and those that have not made that move remain regulated.[3] The retail price of electricity does not vary by time of day in any region, though all customers in competitive regions face prices that vary from season to season.

Each year is subdivided into three seasons (summer, winter, and spring-fall) and each season into four time blocks (superpeak, peak, shoulder, and base). For each time block, demand is modeled for three customer classes (residential, industrial, and commercial) in a partial adjustment framework that captures the dynamics of the long-run demand responses to short-run price changes. Supply is represented using model plants that are aggregated according to their technology and fuel source from the complete set of commercial electricity generation plants in the country. Operation of the electricity system (generator dispatch) in the model is based on the minimization of short-run variable costs of generation and a reserve margin is enforced based on those obtained by EIA in the AEO 2010. Investment in new generation capacity and the retirement of existing facilities are determined endogenously for an intertemporally consistent equilibrium, based on the capacity-related costs of providing service in the present and into the future (going-forward costs) and the discounted value of going-forward revenue streams. Discounting for new capacity investments is based on an assumed real cost of capital of 8 percent. Generator availability, even for highly variable renewable resources, is captured in only a deterministic sense, i.e. no capacity penalty is assigned to account for the probability that a generator may be unavailable when called upon by the system operator.

[3] There is currently little momentum in any part of the country for electricity market regulatory restructuring. Some of the regions that have already implemented competitive markets are considering reregulating, and those that never instituted these markets are no longer considering doing so.

The assumed costs and operational characteristics of new technologies are reported in Table 1. The capital costs change over time and in response to capacity additions (learning-by-doing) based on the learning functions implemented in the NEMS model and described in the documentation of the AEO 2010 (EIA 2010b). Capital costs for technologies that are relatively immature fall faster than those for mature technologies. For example, capital costs for solar thermal generators are projected to fall by 46% by 2035, to $4270 per kW, even in the absence of any new capacity additions. For advanced nuclear plants, a sensitivity scenario is considered assuming that capital costs are 30% higher than those reported in the table.

Table 1. Technology Cost and Performance Assumptions

	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M (mills/kWh)	Heat Rate (Btu/kWh)	Average Capacity Factor (%)
Coal without CCS	2,223	28.15	4.69	9,200	--
Coal with CCS	3,776	47.15	4.54	10,781	--
Conventional Natural Gas Combined Cycle	984	12.76	2.11	7,196	--
Advanced Natural Gas Combined Cycle	968	11.96	2.04	6,752	--
Conventional Natural Gas Combustion Turbine	685	12.38	3.65	10,788	--
Advanced Natural Gas Combustion Turbine	648	10.77	3.24	9,289	--
Advanced Nuclear	3,820	92.04	0.51	10,488	--
Onshore Wind	1,966*	30.98	0.00	--	32-47**
Offshore Wind	3,937*	86.92	0.00	--	34-50**
Biomass	3,849	65.89	6.86	9,451	--
Landfill Gas	2,599	116.80	0.01	13,648	--
Solar Thermal	7,948	58.05	0.00	--	45
Geothermal	1,749	168.33	0.00	32,969	--

* These are the minimum overnight capital costs for wind plants. They are adjusted by multipliers that account for terrain and population density.

** Average capacity factors for wind plants vary by wind class with the minimum and maximum values shown here.

Equilibrium in interregional power trading is identified as the level of trading necessary to equilibrate regional marginal generation costs net of transmission costs and power losses. These interregional transactions are constrained by the level of the available interregional transmission capability as reported by the North American Electric Reliability Council (NERC 2003a; NERC 2003b).[4] Factor prices, such as the cost of capital and labor, are held constant.

[4] Some of the Haiku market regions are not coterminous with North American Electric Reliability Council (NERC) regions, and therefore NERC data cannot be used to parameterize transmission constraints. Haiku assumes no transmission constraints among regions OHMI, KVWV, and IN. NEN and NES are also assumed to trade power without constraints. The transmission constraints among the regions ENTN, VACAR, and AMGF, as well as those among NJD, MD, and PA, are derived from version 2.1.9 of the Integrated Planning Model (U.S. EPA 2005). Additionally, starting in 2014, we include the incremental transfer capability associated with two new 500-KV transmission lines into and, in one case, through Maryland, which are modeled after a line proposed by Allegheny Electric Power and one proposed by PEPCO Holdings (CIER 2007). We also include the transmission capability between Long Island and PJM made possible by the Neptune line, which began operation in 2007.

Fuel prices are benchmarked to the forecasts of the revised AEO 2010 (EIA 2010a) for both level and elasticity. Coal is differentiated along several dimensions, including fuel quality and content and location of supply, and both coal and natural gas prices are differentiated by point of delivery. The price of biomass fuel also varies by region depending on the mix of biomass types available and delivery costs. All of these fuels are modeled with price-responsive supply curves. Prices for nuclear fuel and oil are specified exogenously without any price responsiveness.

Emissions caps in the Haiku model, such as the Title IV cap on national SO_2 emissions, EPA's Clean Air Interstate Rule caps on emissions of SO_2 and NO_x, and the RGGI cap on CO_2 emissions, are imposed as constraints on the sum of emissions across all covered generation sources in the relevant regions. Emissions of these pollutants from individual sources depend on emission rates, which vary by type of fuel, technology, and total fuel use at the facility. The sum of these emissions across all sources must be no greater than the total number of allowances available, including those issued for the current year and any unused allowances from previous years when banking is permitted. To model economy-wide policies that price CO_2 (such as cap-and-trade or an emissions tax), the model includes a reduced-form rest-of-economy CO_2 emissions reduction supply function (based on EIA analysis of H.R. 2454) and two supply curves for emissions offsets, one from domestic sources and the other from international sources (based on offsets supply curves originally generated by EPA and later enhanced by EIA for its H.R. 2454 analysis). These supply curves vary over time.

Scenario Descriptions

This paper explores the effects of three types of policies on U.S. electricity markets, focusing on the use of renewable sources of electricity, CO_2 emissions from the electricity sector, and effects on consumers. The policies, which are described in detail below, are a cap-and-trade program on CO_2 emissions, a renewable portfolio standard, and an extended tax credit policy for renewable generation and investment. All possible combinations of these policies are also considered, which is important given that most recent climate legislation proposals that have had cap-and-trade as a central element have also included other provisions, like RPS, to promote the use of renewables. These policy scenarios are evaluated relative to a baseline scenario, which is described first. All scenarios simulate the timeframe 2010 to 2035.

Baseline Scenario (BL)

The baseline scenario, which is denoted as BL in the text that follows, is calibrated to yield electricity demand levels by region and customer class that match the levels reported in the

AEO 2010 (EIA 2010a). Included in the scenario is a representation of the state-level RPS policies that currently exist in 29 states plus the District of Columbia, aggregated to the 21 Haiku market regions. These policies are characterized by the schedule with which the renewable goals are phased in, the basis of the RPS (sales, generation, capacity, etc), the utilities that are required to comply, the types of qualifying renewable technologies, the extent of interstate trading allowed, and the level of any alternative compliance payment (ACP). Also included is a representation of tax credits for renewables that are in place in 6 states (Florida, Iowa, Maryland, New Mexico, Oklahoma, and Utah) and those included in the federal American Recovery and Reinvestment Act (ARRA). ARRA extended the production tax credit available to existing wind generators through 2012 and for other technologies through 2013. It also allowed generators to choose between a production tax credit and an investment tax credit, depending on which provides more benefit.[5]

The BL scenario incorporates several existing environmental policies, including the SO_2 cap-and-trade program under Title IV of the Clean Air Act Amendments of 1990, the Clean Air Interstate Rule[6] restrictions on emissions of SO_2 in the eastern part of the country as well as the annual and ozone season restrictions on NO_x emissions, the cap on CO_2 emissions in the RGGI states (the Northeast), and the state-level mercury MACT programs. All provisions of the BL scenario are assumed to continue under all policy scenarios.

Policy Scenarios

Three core policy scenarios and four scenarios of policy combinations are described below. The core scenarios are based on salient features of existing policy proposals. Sensitivity cases that address scenarios of elevated costs for nuclear capacity and the absence of alternative compliance payment provisions of the RPS policy are also considered. Abbreviated names for the policies are given in parentheses and will be used in the Results section.

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[5] The ARRA policy also allows for renewable generators to opt for a cash grant instead of the tax credit. In the Haiku model, a cash grant is indistinguishable from an investment tax credit because capital is treated as perfectly mobile.

[6] The rule was vacated and remanded to EPA in July 2008 by the federal appeals court, but after a request for rehearing, the court remanded the rule to EPA without vacating, in December 2008. Thus the rule remains in effect while EPA develops a replacement rule that satisfies the concerns raised in the appeals court decision. This new final rule is pending.

Cap-and-Trade Program (CTP)

The CTP policy simulates an economy-wide cap-and-trade program on CO_2 emissions based on H.R. 2454, which was passed by the House of Representatives on June 26, 2009. The emissions targets would reduce U.S. emissions of CO_2 from major sources by 17 percent in 2020 and by 80 percent in 2050 compared with 2005 levels. The CTP policy is modeled to include unlimited allowance banking and the same restrictions on offsets use that were specified in the bill: up to 2 billion tons of offsets annually, with no more than 1.5 billion from foreign sources. The scenario modeled here differs from H.R. 2454 in the treatment of allowance allocation, by modeling an allowance auction with no revenue recycling.[7] The CTP policy does not include any targeted provisions to promote renewables other than those in the baseline.

Renewable Portfolio Standard (RPS)

The RPS policy is modeled with the targets, timetables, and an alternate compliance payment (ACP) level equivalent to the RPS policy included in Title I of H.R. 2454. This policy imposes a floor on the percentage of electricity sales that must be generated with qualified renewable technologies, which include biomass, solar, wind, and geothermal. Under the policy, each MWh of electricity generated by a qualified technology creates a renewable energy credit, and these RECs are fully tradable in a national market. The policy ramps up to a 20 percent renewable standard by 2020 and thereafter, and the ACP is set at $25 per MWh, which serves as a cap on the price of RECs and generates government revenue.[8] The RPS scenario is different from the H.R. 2454 RPS in at least two important ways. First, whereas the bill allows for energy savings from investments in efficiency to count for a portion of the portfolio standard, the RPS scenario modeled here does not include this feature. Second, H.R. 2454 exempts from the RPS requirement utilities that sell less than 4 billion kWh per year and allows for REC banking over a three-year period, but the RPS scenario modeled here includes no such provisions and is thus more stringent.[9] As the results below will show, the ACP proves to be a very important feature of the RPS policy, so a sensitivity version of the RPS policy that includes no ACP is also considered; it is labeled RPS_noACP.

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[7] H.R. 2454 would allocate 30 percent of the allowances to local distribution companies to offset consumers' electricity bills. This allocation would end by 2030.

[8] The ACP is assumed to grow at the rate of inflation and thus be fixed in real terms.

[9] H.R. 2454 also excludes from the basis for the RPS policy any generation from incremental nuclear capacity, from hydropower facilities, and from fossil-fired facilities that include CCS; the scenario modeled here does not.

Tax Credits (TC)

The tax credit policy scenario extends the production tax credit and investment tax credit provisions in the ARRA, including the flexibility to pick one or the other, through 2035.

Policy Combinations

In addition to these single-policy core scenarios, four scenarios of policy combinations are also modeled: the RPS in combination with the TC (RPS+TC), the cap-and-trade policy combined with the RPS (CTP+RPS), the cap-and-trade policy combined with the TC (CTP+TC), and all three policies combined (CTP+RPS+TC). The RPS sensitivity policy that lacks an ACP is also included for each combination scenario. These are RPS_noACP+TC, CTP+RPS_noACP, and CTP+RPS_noACP+TC.

Nuclear Cost Sensitivity

Recent estimates of the costs of a new nuclear plant are substantially higher than what EIA assumed in its AEO 2010 (EIA 2010a) forecast, and since nuclear is an important zero-carbon-emitting competitor to renewables, it is important to see how this assumption affects the use of renewables both in the baseline and in the policy scenarios. Therefore, sensitivity scenarios that assume nuclear capital costs are 30 percent greater than in all other scenarios are considered. Haiku incorporates learning functions that lead to endogenous capital cost declines over time and as new capacity installations accumulate, so the 30 percent increment applies to the initial kernel cost. The 30 percent scenarios have initial nuclear capital costs of $4,966 per kW. These sensitivity cases are solved for scenarios with the following abbreviated labels: BL@N30, CTP@N30, CTP+RPS@N30, CTP+TC@N30, CTP+RPS+TC@N30. The other core and combination scenarios are not included because the nuclear cost assumption has little effect on the BL scenario and the use of nuclear is not much affected by the TC and RPS scenarios; thus they were excluded from the sensitivity analysis.

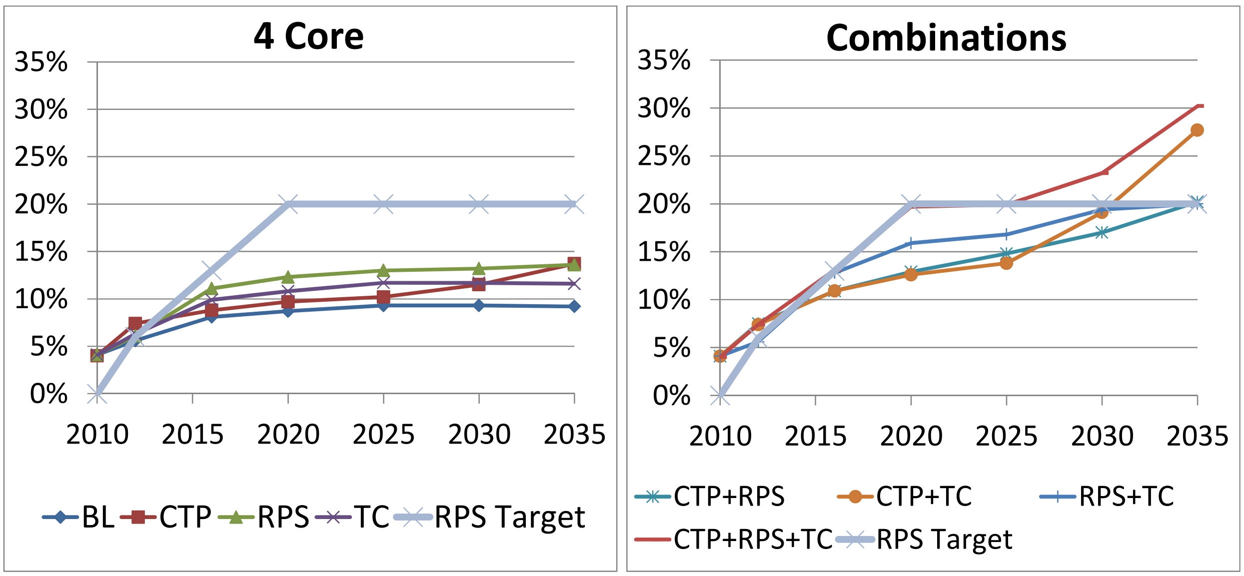
Results

The results of the simulations offer insights into the quantitative effects of the policies, combination scenarios, and sensitivity cases on several metrics of interest, including renewable energy deployment and REC prices, generation mix, electricity prices, CO_2 emissions, and emissions reductions cost-effectiveness. This section also addresses interactions among these federal policies and between the federal policies and the state renewable policies. All the monetary results are reported in real 2008 dollars. The results are presented primarily as figures; the numbers behind most of the figures are available in the Appendix (Tables 4–7).

Renewables Penetration and REC Prices

The effects of the different policies on the percentage of national generation met by renewables in each year are shown in Figure 2. The left-hand panel focuses on the core scenarios, and the right-hand panel displays the results for the four combination scenarios. Each graph also shows the RPS target.

Figure 2. Renewables Penetration



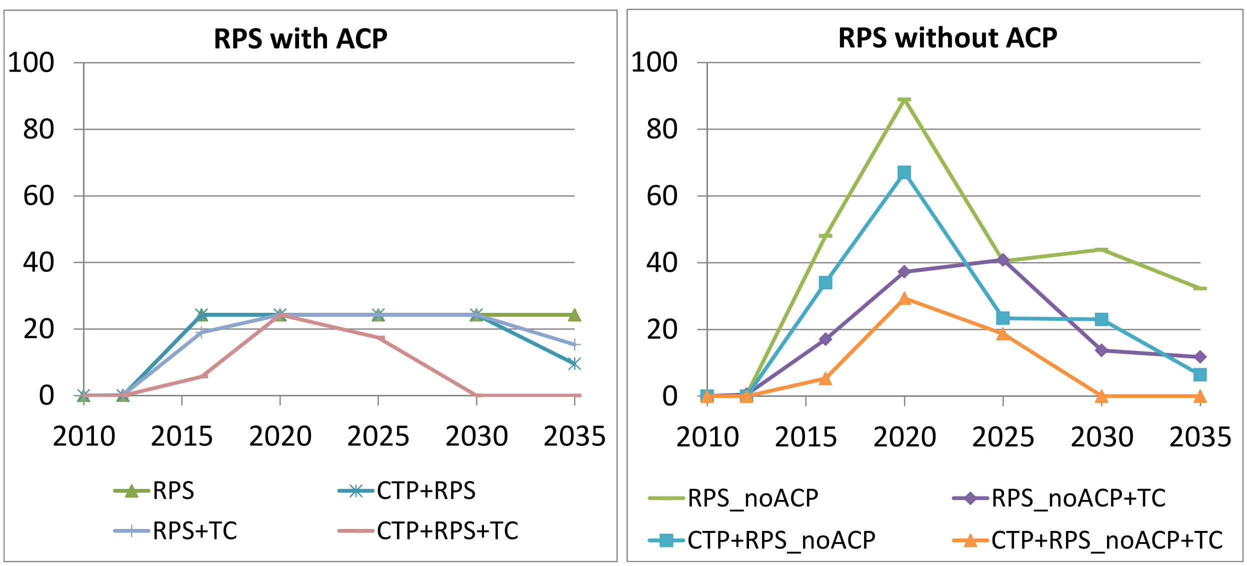
The left-hand panel reveals that over most of the modeling horizon, the RPS is the most potent policy for encouraging renewables, followed by the TC and then the CTP.[10] After 2012, the renewables share with the RPS is below the target because the ACP is binding. This implies that if the RPS is combined with another policy that either lowers the cost of renewables (as does the TC) or makes fossil technologies less attractive relative to renewables (as does the CTP), then those policy combinations can yield higher renewables shares than the RPS alone. This result is shown in the right-hand panel. Under the CTP+RPS+TC scenario, the renewables share is at the target in 2016 and 2025 (it is below the target by 0.3 percent in 2020), when the ACP does not bind but the RPS requirement does. After 2025 the RPS is no longer binding, and the renewables share climbs to about 30 percent by 2035. For the other combination scenarios that include an RPS, the RPS target is binding throughout, and the ACP is binding from 2020 through

[10] Note that because we do not exclude small utilities from the requirement, this standard is more stringent than the actual RPS proposed in H.R. 2454.

2030 (also in 2016 for CTP+RPS) but no longer by 2035. The CTP+TC policy achieves a renewables share like that of the CTP+RPS scenario through 2025, and thereafter, renewables rise quickly.

The time path of REC prices is displayed in Figure 3. The left-hand panel shows the REC prices for the four scenarios that include an RPS and illustrates the binding ACP that was implied in Figure 3. The right-hand panel shows REC prices under the scenarios that include an RPS but lack an ACP. Inevitably, these scenarios yield REC prices significantly higher than the prices that obtain with an ACP in the years that the ACP is binding. In some years, the REC prices in the absence of an ACP are lower than in the presence of the ACP because of investment dynamics. For example, the REC price in 2035 under the CTP+RPS scenario without an ACP is below that of the scenario with an ACP because of the increase in renewables penetration (and corresponding decrease in nonrenewables capacity) in years prior. This difference makes RPS compliance easier in 2035, and the REC price falls accordingly. The RPS is nonbinding beginning in 2030 in the CTP+RPS+TC scenario regardless of the presence or absence of an ACP.

Figure 3. REC Prices ($/MWh)

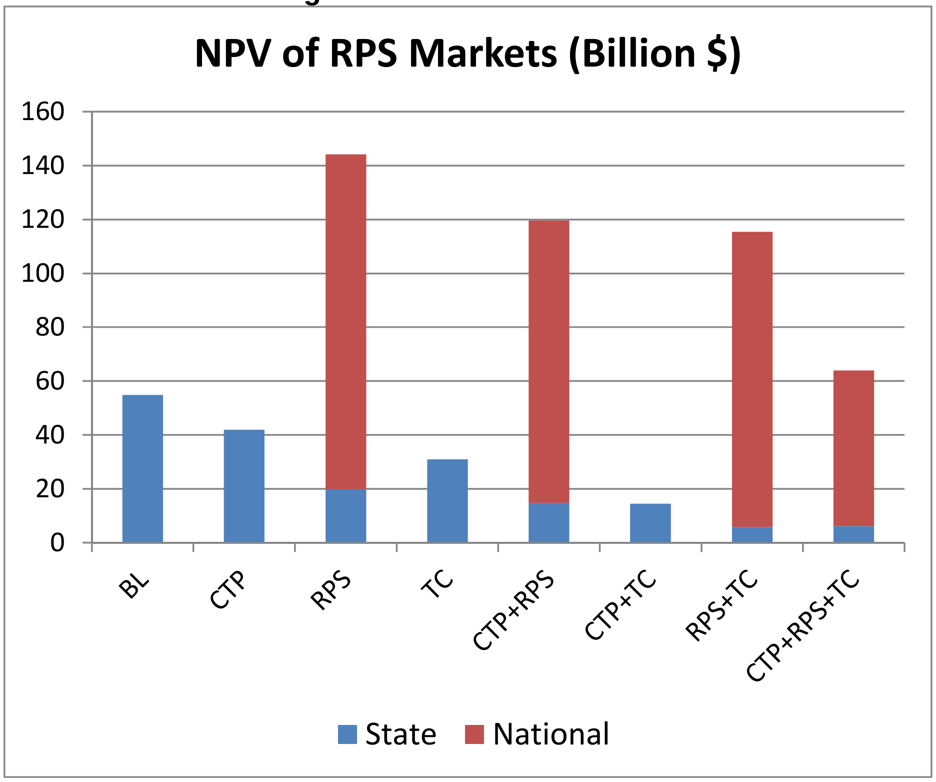


This analysis also allows us to look at the interactions between state and federal RPS policies. Despite the increase in renewable generation that is induced by all the policies, many state RPS policies are still binding under the single-policy scenarios, especially in the eastern part of the country. For example, under the federal RPS, which induces the largest expansion of renewables, most of the state RPS policies west of the Mississippi bind in only 2010, before the national RPS is in effect, but all the state RPS policies east of the Mississippi are binding in

2020–2035. This is because a large portion of the renewables expansion driven by a national RPS occurs in the western half of the country, so the eastern states still require additional renewables to meet their state RPS requirements. As the federal policies are combined, however, the eastern United States begins to experience a greater expansion of renewables, pushing the state RPS policies closer to nonbinding. Under CTP+RPS+TC, for example, the only state with a binding RPS in the later years of this analysis is New York, which has a very stringent RPS requirement of 30 percent renewables (including hydro) beginning in 2015.

Figure 4 illustrates the size of the state and federal REC markets in each scenario as the net present value (discounted at 8 percent) of total REC and ACP costs incurred by nonrenewable generators. These include the total value of state and federal RECs and all ACP payments for both federal and state policies under each scenario. The first lesson to be drawn from the figure is that the costs generated by the federal RPS policy will be much greater than those associated with the preexisting state policies, no matter the combination of policies that accompany the federal RPS. Secondly, and inevitably, the quantity of renewables that is engendered by the core policies and combination scenarios will be positively correlated with the reduction in the size of the markets for state RECs.

Figure 4. REC Market Value



Generation Mix

The mix of technologies and fuels that emerges under the various scenarios is particularly affected by the presence or absence of the CTP, and affected less by the RPS and TC. This is illustrated in Figure 5, which shows the mix over time for each of the scenarios that include the ACP.[11] The top four panels of the figure show the core policies, and the bottom four show the combination scenarios. Generally, the presence of the CTP drives a substantial shift in the generation mix from coal and natural gas to nuclear and wind. Among renewable technologies, wind and biomass show expansion potential, but other technologies remain priced out of the market.

Comparing the panels of the figure reveals some interesting results related to policy interactions. First, both RPS and TC are made more potent in terms of renewable generation expansion by the presence of CTP, since CTP closes the cost gap between renewables and other technologies. This occurs even though the CTP policy reduces overall electricity demand. The second observation is that despite the binding ACP level in the RPS scenario and because of the level of the tax credits, the RPS leads to more additional renewable generation compared with BL than does the TC.[12] However, when the CTP is in place, the TC is incrementally more potent at encouraging renewable generation than the RPS. The relative potency of RPS and TC depends on the presence of the CTP and its design. For an RPS with no ACP (or a nonbinding ACP), the RPS rewards renewables only up to the floor established by the policy, but the TC rewards all incremental renewables. In the RPS scenarios modeled here, the ACP is binding in all years prior to 2035, which renders the generation floor effect irrelevant in those earlier years, but in 2035 the REC price falls substantially when the CTP is in place (see the left-hand panel of Figure 3). This lower REC price in 2035 affects investments in all years prior, since investors consider the long-run payoff when making choices in earlier years. Thus, although the incremental incentives provided by the TC are not dependent on the presence of the CTP (i.e., the level of the TC does not change), the incremental incentives provided by RPS are less in the presence of the CTP because the REC price is lower in the later years.

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[11] The data for the figure for the years 2020 and 2035 are given in the Appendix.

[12] The share of renewables that is induced by the TC scenario is consistent with the findings of Palmer and Burtraw (2005). However, the effect of the TC policy relative to BL is smaller. This occurs because the baseline in this analysis includes several state-level RPS policies that result in higher baseline renewables. There is also more nuclear generation in the future in the current baseline scenario than there was in the Palmer and Burtraw analysis.

Figure 5. Generation Mix (TWh) for Core and Combination Scenarios

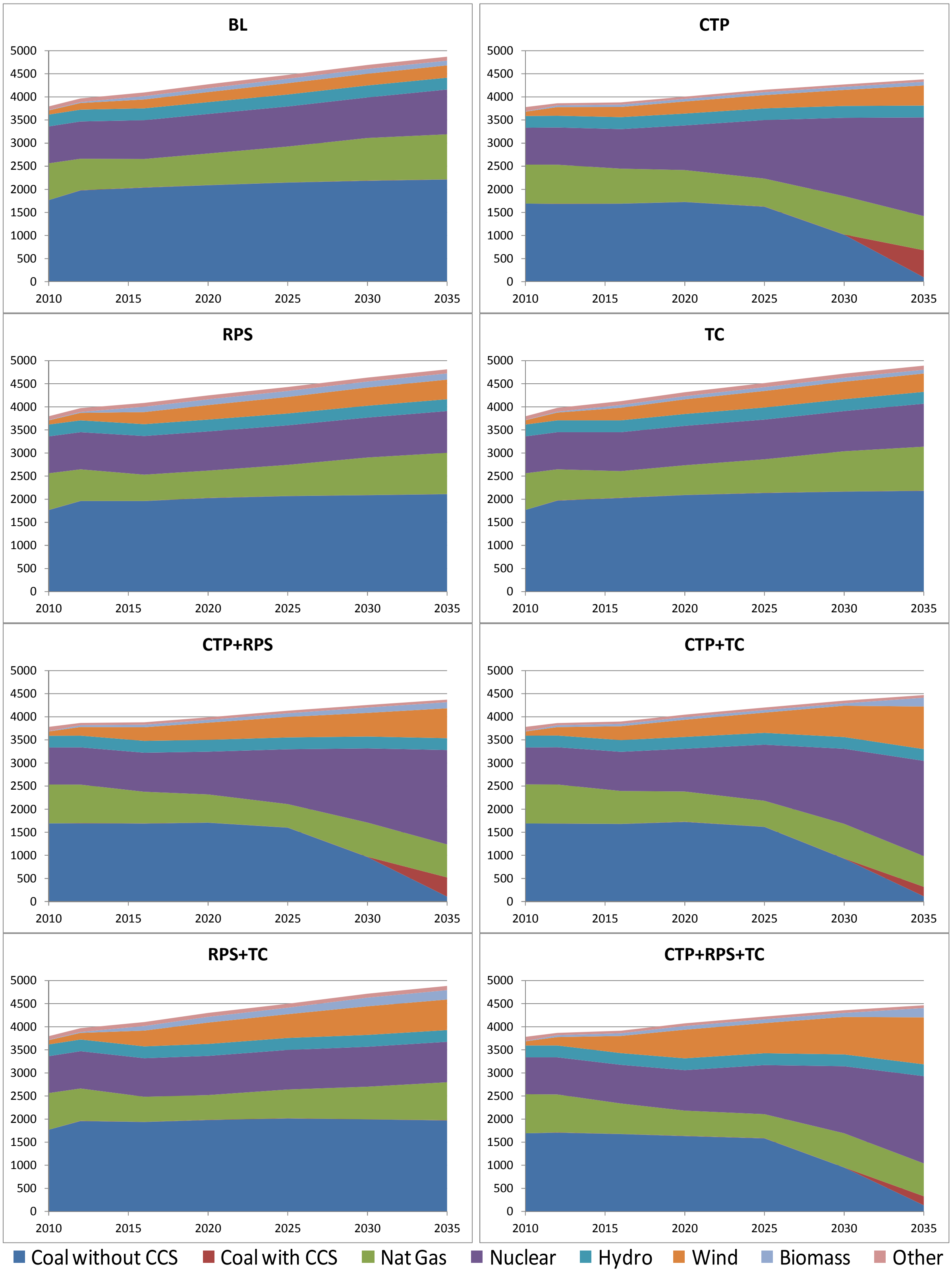
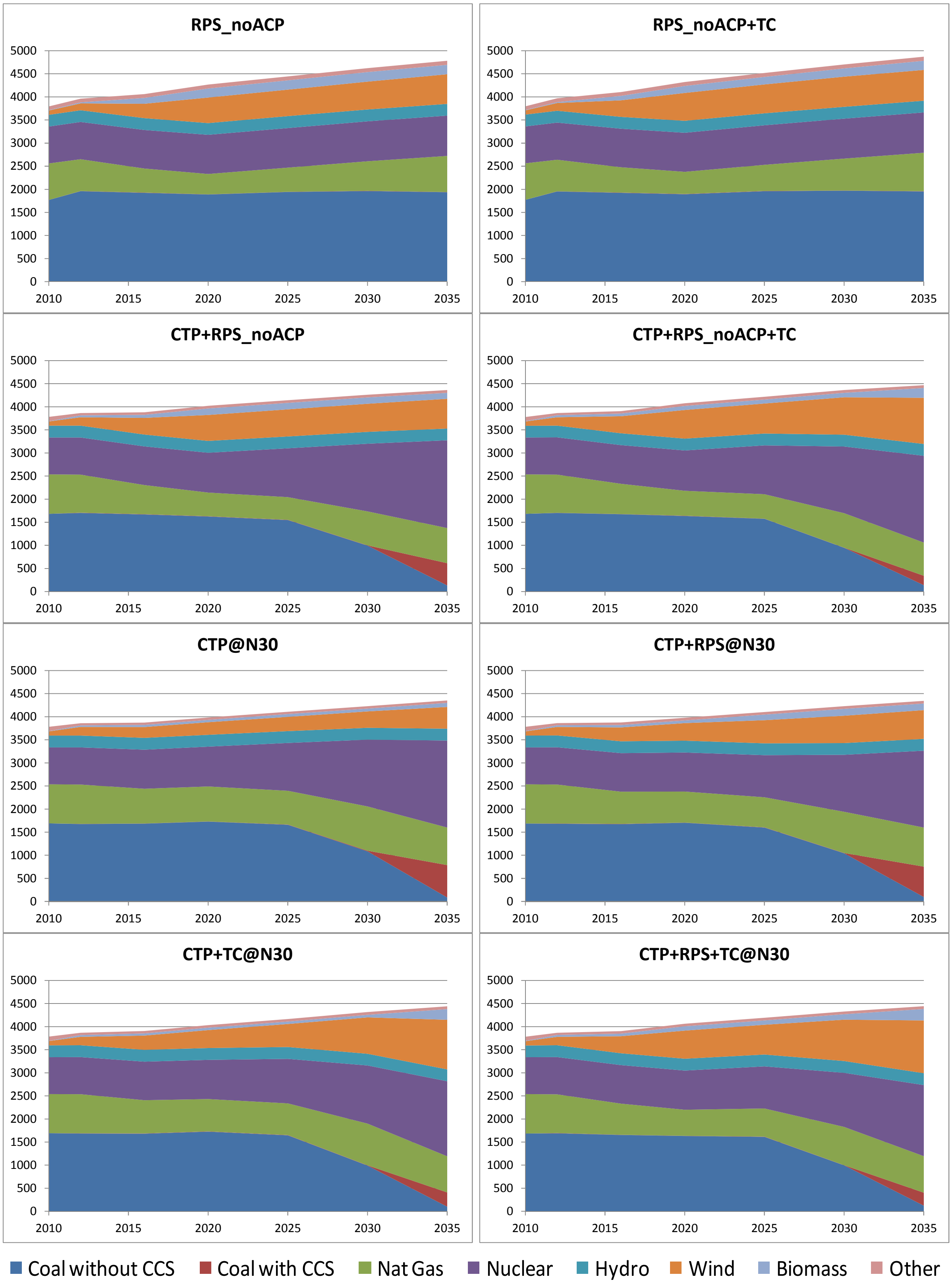


Figure 5 also shows that an expanded role for nuclear is an important outcome of the CTP policy. Nuclear generation increases by 100 percent or more in 2035 in all the CTP scenarios relative to the baseline, but the RPS scenario results in 5 percent less nuclear generation in 2035 than the baseline. The CTP policy also brings in coal with CCS after 2030. However, when the RPS, TC, or both are combined with the CTP, the role for coal with CCS diminishes. The CTP also affects the composition of both the wind and the biomass that are included. Biomass cofiring plays an important role under the RPS and TC policies in isolation, but with the CTP in place, opportunities for cofiring diminish dramatically and are essentially eliminated in the later years of the time horizon. Thus wind and dedicated biomass play more prominent roles as sources of renewable generation in the CTP scenarios. Most of the wind that gets deployed in the model is on-shore wind, but under the scenarios that include both the CTP and the TC, off-shore wind makes it into the generation mix by 2035.

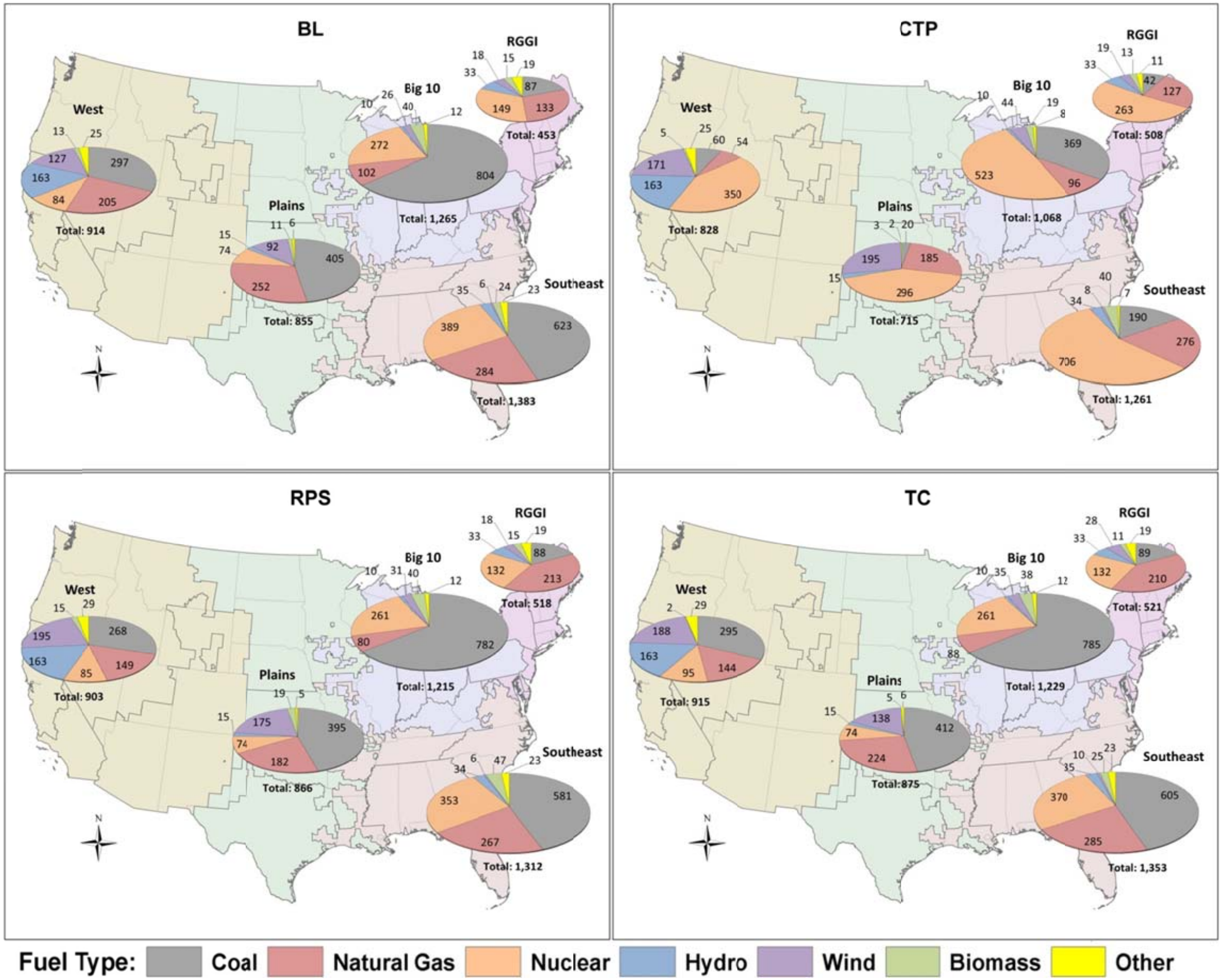
Figure 6 provides the generation mix for the set of cases without an ACP and for the nuclear cost sensitivities. With noACP, the share of generation coming from renewables is substantially larger under the RPS scenario, and the renewables are displacing gas, coal, and nuclear at different points in time. The effect of eliminating the ACP is smaller in the combination scenarios because the combinations made the ACP less binding when it was in effect. The higher nuclear cost cases all result in a slight reduction in nuclear generation compared with their counterparts with standard nuclear cost assumptions, and we see slight reductions in overall generation as well. For the CTP case, the reduction in generation from nuclear is made up by more generation from natural gas, renewables, and coal with CCS. In general, however, the effect of the higher cost on nuclear’s share of generation is not that large, and nuclear is still 22 percent of total generation in 2020 and 43 percent in 2035. Differences in total nuclear generation between the high nuclear cost and standard version of the CTP combination cases are similarly small, and the generation that displaces the lost nuclear generation tends to come from all other available sources, not disproportionately from renewables.

Figure 6. Generation Mix (TWh) for noACP and High Nuclear Cost Scenarios



The policies have different effects on the mix of technologies used to generate electricity across regions of the country. To show these effects, we group the 21 regions in the Haiku model into five regions of the country, as illustrated in Figure 7. This figure shows the composition of total electricity generation in 2035 in each region for the baseline and the three policies individually. In general, most of the renewables expansion happens west of the Mississippi. Under all three policies, the share of generation from renewables is roughly the same in the West. However, in the Plains region the amount of generation from wind is largest under the CTP, followed by the RPS and then the TC. In the Southeast and Big 10, renewable generation grows the most under the RPS, with the largest component coming from biomass. In the Big 10, renewable generation actually shrinks under the CTP. This reduction occurs because much of the renewable generation in this region is cofired biomass, and opportunities for cofiring are much reduced under the CTP because of the dramatic reduction in coal-fired generation under that policy. In the RGGI region, the largest growth in renewables happens under the TC policy, which produces lower electricity prices and higher demand, and thus greater demand for generation from renewables. The figure also shows that the amount of coal displacement under the CTP varies by region, with the biggest reduction in coal in the Plains states, where wind resources are readily available.

Figure 7. Regional Generation Mix (TWh) for Core Policies

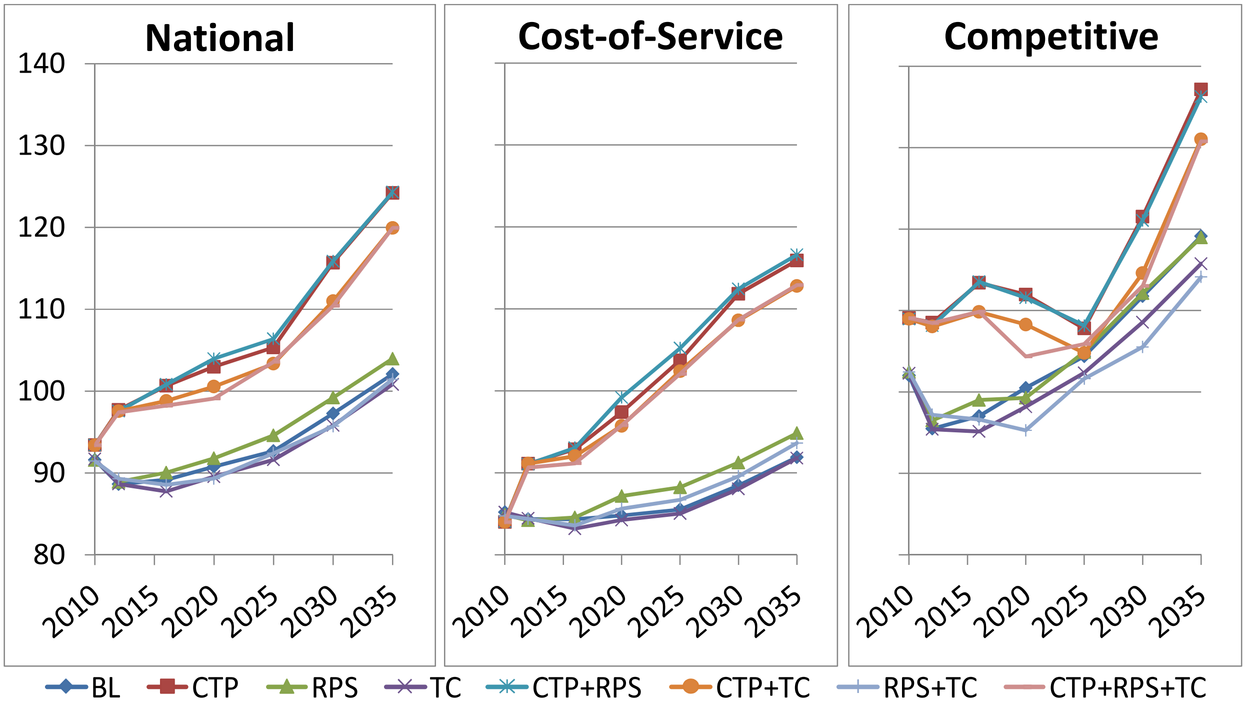


Electricity Prices

The core policies and combination scenarios induce different electricity price effects, and these effects exhibit regional variation according to the regulatory structure governing electricity markets. The left-most panel in Figure 8 shows the trajectory of national annual average electricity prices over the simulation horizon under each scenario. Consider first the three policies in isolation: CTP, RPS, and TC. The CTP policy has by far the biggest effect on electricity prices, causing them to increase by roughly 13 percent in 2020 and 22 percent in 2035 relative to BL.[13] The RPS policy has a much smaller but still positive effect on national average prices, raising them by 1 percent in 2020 and 2 percent in 2035 relative to BL. The TC policy induces a slight electricity price decline of roughly 1 percent compared with BL in both 2020 and 2035. Similar incremental effects of the CTP, RPS, and TC are revealed when comparing the combination scenarios.

[13] The magnitude of this effect depends importantly on the assumption that emissions allowances are allocated by auction. If instead some portion of allowances were allocated to local distribution companies, as proposed under H.R. 2454, the effect on electricity prices would be smaller nationwide. If they were grandfathered, as under the SO_2 trading program authorized by the Clean Air Act Amendments of 1990, the effect would be smaller in regions that price electricity by cost-of-service regulation but approximately unchanged in regions that price generation services in competitive markets.

Figure 8. Electricity Prices ($/MWh)



The middle and right-hand panels of Figure 8 show the electricity price effects broken down by electricity market regulatory structure, with the average across the cost-of-service regions in the middle panel and the average across the competitive regions on the right. In the cost-of-service regions, the CTP policy has larger effects than it does in the competitive regions.[14] This is partly because the cost-of-service regions have historically been more heavily dominated by coal-fired generation. The other finding revealed by the two right-hand panels of this graph is that the effect of an RPS on electricity prices tends to be positive in the cost-of-service regions but negative in the competitive regions. When electricity is priced on the margin, as it is in competitive regions, adding more wind, which has a very lower marginal cost, tends to

[14] The electricity price decline in the competitive regions over the period 2016–2025 under the scenarios that include CTP is driven primarily by the timing of investments in new nuclear capacity and retirements of existing coal capacity. Nuclear investments begin in earnest in the competitive regions in 2020 and reach about 17 GW by 2025. There is no retirement of coal capacity over this timeframe, but there is significant coal retirement immediately thereafter. The net influx of capacity over 2016–2025 drives prices down. The net retirement immediately thereafter drives prices back up.

lower the market-clearing price for energy. If the effect of the REC price on the cost of marginal fossil generators is not high enough to offset the first effect, then prices in competitive regions will fall with an RPS. This means that it is the producers in these regions who bear the cost of this policy. This is consistent with findings in Fischer (2010) and studies surveyed in Wiser and Bolinger (2007). Other studies surveyed in Fischer and Preonas (2010) also find that combining an RPS with a cap-and-trade policy can lead to lower electricity prices.[15]

Electricity prices under the RPS_noACP sensitivity scenarios can either increase or decrease relative to the standard RPS scenarios, and this result varies over time and the other policies included. The outcome depends on the supply curve in competitive regions and the relative renewable generation in the two regions. The noACP scenarios have much higher REC prices in many years than the ACP scenarios, and in the competitive regions the resulting REC prices are sufficient in some years to more than offset the marginal cost reductions that result from the rightward shift of the supply curve by the addition of renewables capacity. The cost-of-service regions increase renewable generation in the noACP scenarios, which necessarily raises costs, but this increase is offset in some years by increased revenue from REC exports to competitive regions.[16] Conceptually, each of these effects has an ambiguous effect on electricity prices, so the national average result is also ambiguous. In the scenarios modeled, there are years when electricity prices decrease in both types of regions, and other years when prices increase in both types of regions, as well as years when the regions experience opposite price effects. At the national level, this results in nonuniform price effects from removing the ACP in the RPS policy, although electricity prices never change by more than approximately $1.6 per MWh.

The assumed level of nuclear cost will also influence how the different policy scenarios affect the average electricity price. In the BL@N30 scenario, increasing the capital costs of new nuclear investments has a small effect on electricity prices—less than $0.50 per MWh in all

[15] One qualification to these results involves the use of power purchase agreements. A power purchase agreement is a long-term agreement between a renewable generator and an entity, either an electricity distribution company or another type of electricity retailer, that commits the retailer to purchase some portion of the output of the generator on predetermined terms. Under such an arrangement, the generator is guaranteed a particular price for its power, and the effect of adding a renewable facility to the low end of the power dispatch curve may be muted either in general or at particular times of the day, since the full cost of retail companies' obligations under the power purchase agreement is presumably passed on to consumers in retail electricity rates. The extent to which this is likely to happen depends on the relationship between the contract price of power and the marginal cost in the market at any given point in time.

[16] This assumes that the owners of renewables are regulated entities.

years. This is because BL includes only a small amount of new nuclear investments, so increasing capital costs does not have a large effect on prices. In the CTP policy scenario, nuclear capacity expansion is much greater, so the CTP@N30 scenario yields electricity prices that are nearly $3 per MWh higher in some years than in the CTP scenario. The rest of the scenarios with increased nuclear costs have electricity price increases relative to the scenarios with baseline nuclear costs that fall within this range of $0.5 per MWh to $3 per MWh.

The effects of the different policies on regional electricity prices in the five geographic regions (see Figure 7) are reported in Table 2. The differences across regions are the result of a culmination of the following attributes that differ across the regions:

- the mix of technologies currently used to generate electricity;
- the regulatory treatment of electricity markets; and
- the availability of renewable resources.

The table shows the effects of each policy and policy combination on regional average electricity price in 2035 expressed in both $/MWh and percentage terms. The CTP yields the largest price increase in the Plains region, followed by the Big 10 and then the Southeast. The West and RGGI, which are much less reliant on coal-fired generation, experience a much smaller price effect under the CTP. In most regions the RPS produces a small increase in electricity price, with the smallest increases occurring in the West and the Big 10. In RGGI, however, electricity prices actually fall under the RPS. This occurs because all of Haiku market regions that comprise RGGI have competitive electricity pricing, and thus electricity price is determined by marginal cost. The drop in price means that the additional costs associated with meeting the RPS tends to be absorbed by producers in the form of lower producer surplus. In average-cost regions, all the costs associated with using more renewables are passed on to consumers, so prices will increase as long as REC exportation does not generate enough revenue to lower total average cost. On the other hand, the TC policy lowers price in all regions, but the largest price decline under this policy happens in the RGGI region.

Removing the ACP from the RPS policy tends to lead to bigger price effects in both the negative and the positive directions. The simple RPS_noACP scenario has an even bigger negative effect on electricity price in RGGI than the regular RPS scenario, while in other regions and for the nation as a whole, the positive effect on price tends to be bigger for the RPS_noACP scenario than for the straight RPS. For the combination policies, removing the ACP tends to have a very small effect on prices.

With higher nuclear costs, the average national price effect of the different policies in 2035 tends to be about $2 per MWh higher than with the standard nuclear cost assumption. However, there is considerable variation both across regions and across policies. In general, the Plains and the West both see smaller price increases in this sensitivity case than the regions in the East, where nuclear generation tends to play a more important role. In the Plains and the West, CTP+RPS is the scenario where prices increase most because of the higher nuclear costs, but in the Southeast the higher nuclear costs produce the biggest price effect in the CTP+RPS+TC scenario.

Table 2. Regional Price Effects in 2035: for BL, \$/MWh; for others, Δ \$/MWh from BL and %Δ

	RGGI	West	Big 10	Southeast	Plains	National
BL	150.7	104.2	90.9	92.2	99.4	102.1
CTP	+13.7	+14.5	+24.3	+22.2	+31.0	+22.1
	(+9%)	(+14%)	(+27%)	(+24%)	(+31%)	(+22%)
RPS	-3.6	+0.9	+1.4	+3.7	+3.6	+1.9
	(-2%)	(+1%)	(+2%)	(+4%)	(+4%)	(+2%)
TC	-7.0	+0.0	-1.4	-0.3	-0.4	-1.3
	(-5%)	(+0%)	(-2%)	(-0%)	(-0%)	(-1%)
CTP+RPS	+12.0	+15.1	+24.1	+23.3	+30.5	+22.2
	(+8%)	(+15%)	(+26%)	(+25%)	(+31%)	(+22%)
CTP+TC	+6.0	+11.8	+18.7	+20.7	+24.5	+17.9
	(+4%)	(+11%)	(+21%)	(+22%)	(+25%)	(+17%)
RPS+TC	-8.9	-0.2	-2.3	+2.4	+1.3	-0.6
	(-6%)	(-0%)	(-2%)	(+3%)	(+1%)	(-1%)
CTP+RPS+TC	+5.9	+12.6	+18.7	+20.0	+24.9	+17.8
	(+4%)	(+12%)	(+21%)	(+22%)	(+25%)	(+17%)
RPS_noACP	-5.3	+4.6	+0.9	+5.7	+4.5	+3.0
	(-4%)	(+4%)	(+1%)	(+6%)	(+5%)	(+3%)
RPS_noACP+TC	-9.3	+0.7	-2.1	+2.3	+1.3	-0.5
	(-6%)	(+1%)	(-2%)	(+2%)	(+1%)	(-0%)
CTP+RPS_noACP	+9.6	+19.3	+24.1	+22.9	+31.5	+22.8
	(+6%)	(+18%)	(+27%)	(+25%)	(+32%)	(+22%)
CTP+RPS_noACP+TC	+5.9	+12.5	+19.2	+20.2	+25.2	+18.1
	(+4%)	(+12%)	(+21%)	(+22%)	(+25%)	(+18%)
CTP@N30	+15.9	+16.5	+26.6	+23.5	+31.8	+23.8
	(+11%)	(+16%)	(+29%)	(+25%)	(+32%)	(+23%)
CTP+RPS@N30	+14.9	+17.3	+26.2	+24.6	+33.0	+24.3
	(+10%)	(+17%)	(+29%)	(+27%)	(+33%)	(+24%)
CTP+TC@N30	+9.9	+12.8	+20.9	+22.0	+26.8	+19.8
	(+7%)	(+12%)	(+23%)	(+24%)	(+27%)	(+19%)
CTP+RPS+TC@N30	+9.1	+13.0	+20.7	+21.7	+26.6	+19.6
	(+6%)	(+13%)	(+23%)	(+24%)	(+27%)	(+19%)

CO_2 Emissions and Allowance Prices

The CTP policy has a very different effect on CO_2 emissions than do the other policies, yielding significantly greater reductions. This follows from the fact that the penalty imposed upon generators under CTP depends on CO_2 emissions rates, and therefore differentially affects coal, natural gas, and nuclear generation. The other policies treat these types of generation as equivalent and so any expansion of renewables generation displaces a more carbon-intensive portfolio under CTP than under the other policies. This section focuses on the different policies' effects on CO_2 emissions from the electricity sector; the effects outside the electricity sector are small and swamped by the power sector effects. The CTP scenarios have identical cumulative economy-wide CO_2 emissions, except for minute differences that are within the convergence criteria of the model. The scenarios that do not include the CTP have identical emissions outside the electricity sector.

Figure 9. Cumulative Emissions Reductions (billion tons CO_2)

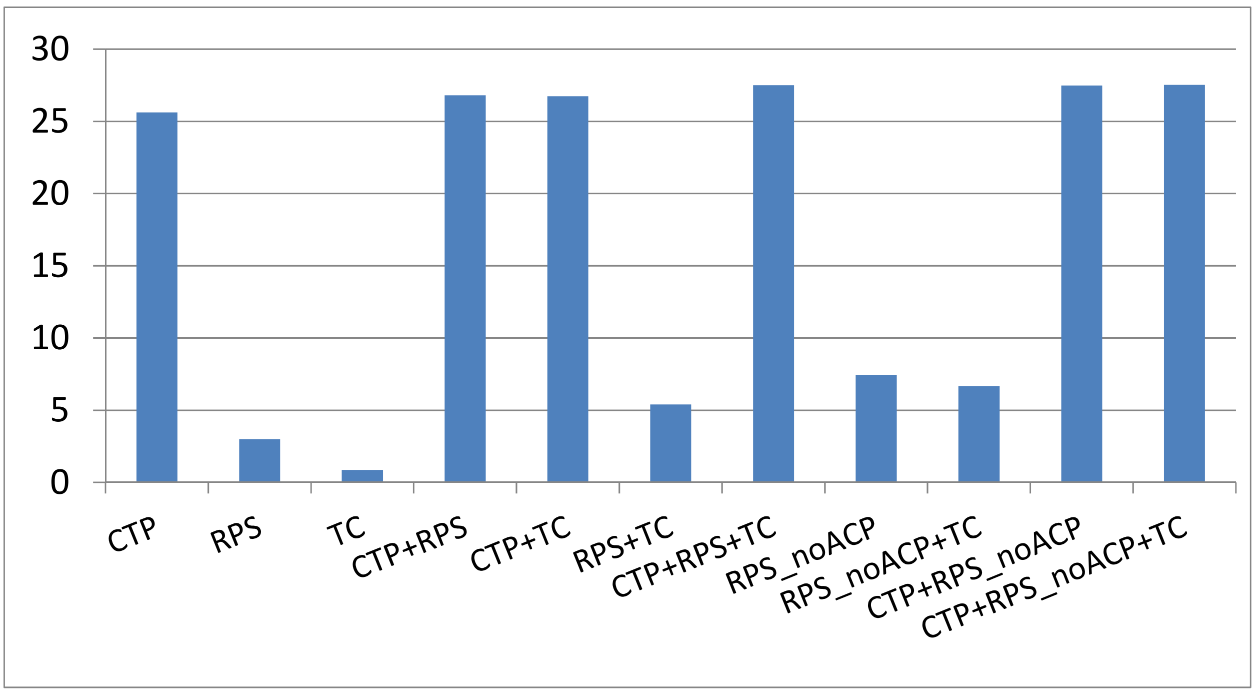


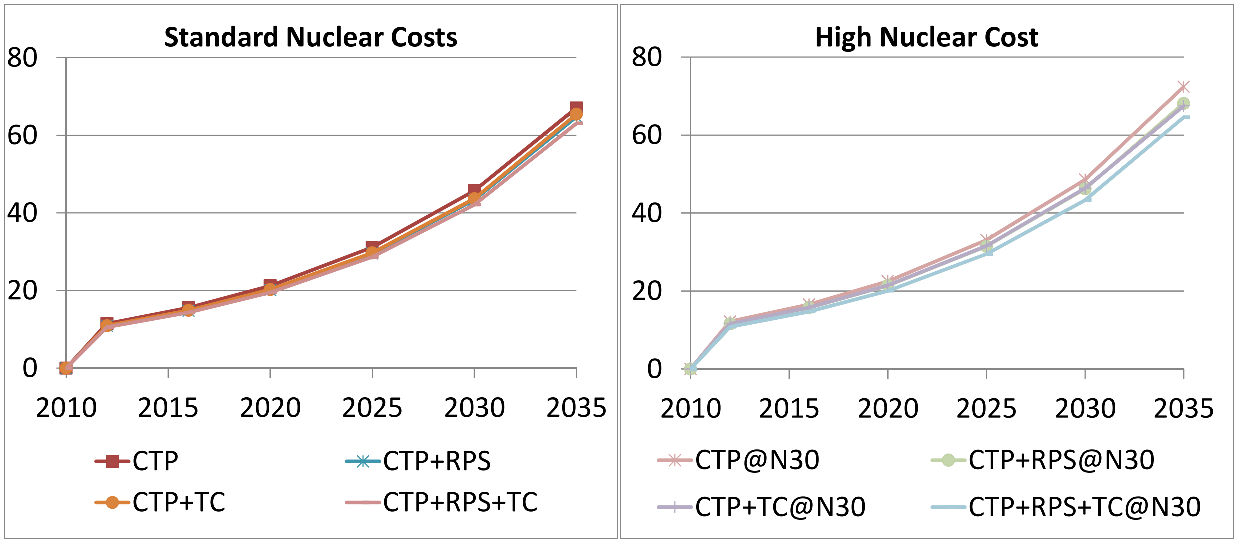
Figure 9 shows the cumulative (2010–2035) reductions in CO_2 emissions from the electricity sector under the core policies and policy combination scenarios, and scenarios without an ACP. The figure clearly shows that for all the policies that include a CTP, the reductions are larger than for the RPS or TC policies. This occurs even though the penetration of renewable technologies are roughly similar (see Figure 2 and Figure 5) because CTP displaces a more carbon-intensive mix of generation than the other policies. The magnitude of this result hinges partly on cost assumptions, especially those for capital costs of new nuclear and renewables capacity, which are highly uncertain. A comparison of the RPS and TC policies reveals that the RPS policy yields more emissions reductions than the TC, and this is exaggerated when the RPS has no ACP. [17] When the ACP is binding, adding a TC to the RPS further reduces CO_2 emissions. However, when there is no ACP, adding the TC to the RPS actually increases cumulative CO_2 emissions relative to the baseline. This occurs because the RPS target is already being met, so the TC does not increase the share of generation coming from renewables but does lower electricity prices (as discussed in the previous section), which increases total generation, including generation by nonrenewables. The figure also shows that adding a TC or an RPS to a CTP leads to greater emissions reductions within the electricity sector, though they are exactly offset by lesser reductions outside the sector since cumulative economy-wide emissions are governed by the allowance cap. These shifts of reductions into the electricity sector occur because the addition of a TC or an RPS to a CTP makes electricity sector reductions more affordable, and so more are harvested.

The left-hand panel of Figure 10 shows the time path of CO_2 allowance prices for core and combination scenarios that include a CTP. When a CTP policy is combined with either an RPS or a TC, the allowance price in 2035 is about $2 below its level under the CTP policy by itself. When both policies are added to the CTP, the allowance price is about $4 below its level with the CTP alone.[18] The right-hand panel shows allowances prices under the four scenarios of increased costs for nuclear capacity. The pattern across these scenarios is like that of the left-hand panel, but allowances prices are systematically about $2 to $5 higher in 2035 when nuclear costs are 30 percent higher.

[17] Palmer et al. (2010) find relative emissions reductions between CTP and RPS that are similar to the findings here. They find about 25% as many emissions reductions under an RPS with an ACP that rarely binds as under a CTP policy.

[18] These allowance price differences across policies are slightly overstated relative to those that would emerge under H.R. 2454, since the modeling horizon ends (in 2035) prior the sunset date of the House legislation (2050). The legislation allows for allowance banking, but Haiku cannot characterize emissions beyond the modeling horizon and so is set to achieve cumulative emissions levels through 2035 instead of through 2050.

Figure 10. CO_2 Allowance Prices (\$/ton CO_2)



Policy Evaluation

One of the objectives of each policy is to reduce greenhouse gas emissions. As discussed in previous sections, the policies have significantly different CO_2 emissions effects and electricity price effects. In this section, we evaluate the policies on cost-effectiveness grounds, accounting for CO_2 emissions reductions, total costs—including those borne by consumers, producers, and government—and electricity consumption. The policies' other objectives, aside from climate change mitigation, such as cost reductions for renewables achieved through learning-by-doing, employment, and investment risk mitigation for renewables, are discussed at the end of this section.

The conventional way to assess cost-effectiveness is to divide costs, measured in economic welfare terms, by benefits. The measurement of consumer welfare is complicated by the opportunity for consumers to substitute end-use capital energy efficiency for electricity consumption. The Haiku demand module captures this substitution by a reduced-form representation of the dynamics of electricity consumption through a partial adjustment representation of electricity demand: when the electricity price increases, consumers adjust their capital stock, and demand is lower in the future. This methodology provides sound estimates of the effects of policies on the levels of electricity consumption but is not explicit about the costs incurred to achieve the implied levels of end-use energy efficiency. Therefore, this assessment of the cost-effectiveness of the different policies will be based not on a complete measure of economic welfare, but rather on total costs normalized by electricity consumption levels.

The first column of Table 3 shows total costs incurred within the electricity sector (i.e., the costs of generating and delivering electricity) and by the government (including tax credit expenditures and ACP payment revenues) for each scenario, expressed in net present value (NPV) terms[19] over the entire modeling horizon of 2010–2035. The ranking of scenarios by total costs may not be intuitive; for example, the RPS scenario has slightly lower costs than the BL scenario, but this is explained by the relative electricity consumption levels. The RPS scenario yields an increase in electricity prices relative to BL, which in turn results in a decrease in electricity consumption that is proportionally greater than the decrease in costs. Therefore, costs per unit consumption are greater under the RPS than under BL, as shown in column 3. This normalized measure of costs is computed using total consumption over the modeling horizon discounted in the same manner as total costs (shown in column 2). Consumption is discounted to reflect the fact that reductions in the near term are more highly valued than those further in the future. Reductions in CO_2 emissions are shown in column 4; these are not discounted because the timing of CO_2 emissions is relatively unimportant over this 25-year period, which is so much shorter than the residence time of CO_2 in the atmosphere. Column 5, the quotient of the difference in NPV total costs / NPV consumption from BL (calculated from column 3) and the emissions reductions in column 4, is the measure of cost effectiveness.

Table 3. Cost-Effectiveness

	NPV Total Cost B$	NPV Consumption TWh	NPV TC / NPV Cons $/MWh	Emissions Reductions Btons	Cost-effectiveness $/MWh/Btons
BL	3,646.2	46,358	78.65	-	-
CTP	3,700.3	43,964	84.17	58.0	0.0950
RPS	3,642.6	46,140	78.95	3.0	0.0976
TC	3,677.1	46,548	79.00	0.9	0.3995
CTP+RPS	3,695.7	43,899	84.19	58.1	0.0953
CTP+TC	3,737.9	44,261	84.45	58.2	0.0997
RPS+TC	3,721.8	46,476	80.08	5.4	0.2644
CTP+RPS+TC	3,779.4	44,402	85.12	58.2	0.1111

The CTP scenario is revealed to be most cost-effective at reducing CO_2 emissions. The other two policies in isolation, RPS and TC, are each less cost-effective, with the TC scenario being by far the least cost-effective. These results align with economic theory. The TC scenario is least cost-effective because if fails to provide any direct incentive for CO_2-intensive electricity

[19] This calculation uses a discount rate of 8 percent, which is equivalent to that used in the other modules of the Haiku model.

generation technologies to reduce generation or emissions and actually works to encourage higher levels of overall consumption. The RPS scenario is superior to TC on cost-effectiveness grounds because it does provide an incentive for reduced generation by emitting technologies. Under this policy, each unit of generation by nonrenewables, which includes the CO_2-intensive technologies, incurs a cost equal to a fraction of the REC price. In cost-of-service regions of the country, the RPS also tends to raise electricity prices, providing incentives for electricity conservation. The CTP scenario is the most cost-effective because not only does it punish generation by CO_2-intensive technologies, but it does so differentially, according to the level of CO_2 intensity. The CTP scenario also raises electricity prices substantially and therefore provides the strongest incentive for conservation.

The combination policies exhibit cost-effectiveness results that follow from the cost-effectiveness of the policies in isolation. Adding the TC to the RPS increases the cost per MWh per ton by about 70 percent relative to that of the RPS alone, but the combined policy decreases the cost by about 34 percent relative to the TC alone because it achieves substantially larger emissions reductions. Adding an RPS to the CTP does not affect this measure of cost by much, and adding a TC to the CTP creates a slightly larger increase in this average cost measure because the TC mutes the electricity price effects of CTP. The combination of all three policies yields the greatest emissions reductions but is the least cost-effective among the scenarios that include CTP, since the RPS and TC raise costs but deliver virtually no additional emissions reductions relative to the CTP by itself.

Policies to promote renewables may be enacted with objectives in mind other than climate benefits. Renewable technologies are fairly immature in their technological development—some more so than others—and there are presumably cost-reducing benefits from technological learning that would come from greater deployment. If these benefits depend on aggregate deployment and experience, then they will not be internalized by a particular firm, and so there would be an externality argument for using policy to increase deployment to help bring costs down more quickly. Learning-by-doing benefits are captured endogenously in Haiku and so accounted for in this cost-effectiveness analysis. Increasing employment has been another argument for promoting renewable generation during the recent economic downturn, although this argument may apply to many other forms of investment as well. Employment effects are not modeled in Haiku. Another feature of the RPS and TC policies that is not captured in the modeling presented here is their effect on reducing uncertainty for renewables investors. These policies provide a more certain level of payments (TC) or demand (RPS) for renewable generation that reduces investment risk. Evaluating the role of risk in investment decisions is outside the scope of this study.

Conclusions

The future of federal energy and climate policy in the United States is uncertain, but a host of recent proposals suggest that with or without a binding cap on CO_2 emissions, policies to promote renewables are likely to play a role. This analysis shows that the effectiveness of these policies in reducing CO_2 emissions and encouraging deployment of renewables depends on policy design elements and on how the policies are combined. Of the policies analyzed here—

- a cap-and-trade program (CTP);
- a renewable portfolio standard (RPS), with and without an alternative compliance payment (ACP); and
- investment and production tax credits (TC)

—CTP produces cumulative CO_2 emissions reductions that are significantly greater than those from the RPS policy, which in turn are substantially larger than the reductions under a TC. The homogenous treatment of nonrenewable technologies under RPS and TC, which yields a displacement of a relatively low carbon-intensity mix of generators by renewables expansion compared to CTP, is the primary driver of the difference between CTP and the other policies. The magnitude of the difference depends partly on highly uncertain assumptions about technology costs. Adding an RPS or a TC to the CTP policy increases the share of CO_2 emissions reductions from the electricity sector and reduces the allowance price. When a TC and an RPS are combined in the absence of the CTP, the cumulative emissions reductions of the pair of policies are greater than the sum of the effects of the two policies alone. The result hinges on the ACP, which binds frequently under RPS; this occurs because the cost gap between renewables and alternative investments is closed by either policy, making the addition of a second policy more potent than it would be in isolation. The reverse is true when an RPS has no ACP; then the addition of a TC to the RPS actually yields fewer emissions reductions than the RPS by itself because the tax credits are an electricity generation subsidy that lowers electricity prices and therefore increases total electricity generation.

Of the three core policy scenarios, the RPS achieves the highest percentage of generation from renewables, and the TC is the second most potent policy in this regard until late in the 25-year simulation horizon. These results are not inherent features of the policy mechanisms but rather hinge on the levels of the RPS targets, ACP rate, emissions caps, TC level, and assumed technology costs. By 2035 the RPS and the CTP achieve similar levels of renewables penetration, and in general the differences in the level of renewables among these four policies are small. The TC policy is more potent at encouraging renewables when it is combined with the CTP than it is in isolation because of the effect of CTP on the relative costs of renewables and alternative investments, described in the previous paragraph.

This analysis finds that the ACP is an important design parameter of the RPS that affects the ability of the policy to deliver both additional renewables and CO_2 emissions reductions. The ACP can cause a large gap between the renewables target and their actual penetration. It also changes the incremental effects of additional policies on renewables and emissions because the additional policies can help close the gap left by the ACP. The policies are also distinct in their effects on electricity prices. The CTP induces large price increases with some variation in magnitude across different regions of the country. In particular, regions that currently have more coal-fired generation generally experience greater price increases than other regions. The TC results in small decreases in electricity price in all regions because it is a subsidy from taxpayers to renewables producers. The RPS generally raises electricity prices in cost-of-service regions; however, it need not do so if regulated renewable generators are exporters of RECs, in which case the revenue from those exports lowers the local revenue requirement, thus lowering regulated prices. This outcome was observed in a small number of cases in this analysis. An RPS can also lower electricity prices in competitive regions when renewables investments shift the electricity supply curve to the right, thereby lowering marginal generation costs and thus the market-clearing price of electricity. The price-reducing effects of the RPS and TC contribute to their limited effectiveness in reducing CO_2 emissions because lower electricity prices induce additional electricity demand.

The most effective of the core policies, as they are specified here, in terms of reducing CO_2 emissions—the CTP policy—also is the most cost-effective. The RPS is less cost-effective and the TC is the least cost-effective of the three core policies at reducing CO_2 emissions. The TC and RPS are less cost-effective than a CTP because they do not differentiate among nonrenewable technologies or tend to reduce electricity consumption, which is an important part of the cost-effective mix of emissions reduction strategies. The TC is less cost-effective than an RPS because the subsidy to electricity production leads to lower electricity prices and greater electricity consumption and because it imposes no penalty on nonrenewable generation. The cost-effectiveness of policy combinations at reducing CO_2 emissions follows directly from the relative cost-effectiveness of the three core policies. Adding an RPS to a CTP or adding a TC to either of the other policies tends to reduce cost-effectiveness.

Additional policy combinations are likely to emerge from the on-going debate on climate and energy legislation in Washington. For example, several recent proposals for both standalone RPS policies and RPS policies coupled with cap-and-trade include the provision that some portion of the RPS could be met using electricity savings from investments in energy efficiency. In addition, some proposals call for expanding the scope of the RPS to include other sources of low- or non-CO_2-emitting generation, such as generation from incremental nuclear capacity, in the portfolio of technologies that receive credit under the policy. Future research is needed to gain further insights into how these and other modifications to the policies modeled here might affect their ability to reduce emissions, their consequences for consumers, and their cost-effectiveness.

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Appendix

Table 4. National Results in 2020 for Core and Combination Scenarios

	BL	CTP	RPS	TC	CTP+RPS	CTP+TC	RPC+TC	CTP+RPS+TC
Electricity Price ($/MWh)	90.8	103.0	91.8	89.6	104.0	100.5	89.3	99.1
Electricity Consumption (TWh)	4,032	3,786	4,011	4,061	3,773	3,824	4,056	3,851
Electricity Generation (TWh)	4,273	4,006	4,247	4,316	3,988	4,046	4,300	4,074
Coal	2,092	1,728	2,029	2,094	1,711	1,728	1,984	1,637
Natural Gas	682	688	591	641	607	655	536	548
Nuclear	856	967	848	853	927	925	848	874
Hydro	259	256	256	258	255	256	257	256
Renewables	351	366	492	438	488	482	646	759
Wind	215	262	314	315	373	373	464	620
Biomass	85	53	124	69	60	55	125	82
Other Renewables	51	51	54	54	54	54	57	58
Other	34	0	31	33	0	0	28	0
Capacity (GW)	991	945	1,007	1,019	967	976	1,056	1,042
Coal	295	251	288	296	251	251	286	249
Natural Gas	396	371	383	395	366	376	386	366
Nuclear	108	122	107	107	117	117	107	110
Hydro	96	96	96	96	96	96	96	96
Renewables	80	90	115	108	124	123	162	207
Wind	59	73	87	88	105	106	133	184
Biomass	12	8	18	10	10	8	19	13
Other Renewables	9	9	9	9	9	9	10	10
Other	17	14	19	17	13	14	19	14
CO2 Allowance Price ($/ton)	0.0	21.2	0.0	0.0	20.1	20.2	0.0	19.5
Cumulative CO2 Emissions Reductions (M tons)	0	8,718	776	210	8,475	8,445	1,191	8,583
Electricity Sector	0	5,080	776	210	5,312	5,225	1,191	5,655
Rest of Economy	0	550	0	0	522	525	0	507
Offsets	0	3,088	0	0	2,640	2,695	0	2,421
REC Price ($/MWh)	0.0	0.0	24.3	0.0	24.3	0.0	24.3	24.3

Table 5. National Results in 2035 for Core and Combination Scenarios

	BL	CTP	RPS	TC	CTP+RPS	CTP+TC	RPC+TC	CTP+RPS+TC
Electricity Price ($/MWh)	102.1	124.2	103.9	100.8	124.3	119.9	101.4	119.9
Electricity Consumption (TWh)	4,605	4,150	4,554	4,626	4,148	4,229	4,619	4,230
Electricity Generation (TWh)	4,871	4,380	4,813	4,893	4,372	4,471	4,883	4,464
Coal	2,216	681	2,114	2,186	523	319	1,976	330
Natural Gas	975	738	891	951	714	665	822	710
Nuclear	968	2,138	905	931	2,044	2,061	874	1,889
Hydro	256	255	255	256	255	255	255	256
Renewables	423	569	618	536	836	1,170	924	1,279
Wind	268	436	425	398	649	921	660	1,017
Biomass	103	79	136	81	131	191	205	203
Other Renewables	52	53	57	56	56	58	59	59
Other	33	0	32	33	0	0	31	0
Capacity (GW)	1,129	1,059	1,147	1,165	1,107	1,188	1,222	1,213
Coal	308	153	298	306	136	114	289	127
Natural Gas	492	381	476	497	382	388	474	388
Nuclear	119	267	110	114	255	257	107	235
Hydro	96	96	96	96	96	96	96	96
Renewables	99	148	149	135	226	321	238	355
Wind	75	123	120	113	192	278	196	309
Biomass	15	16	20	13	25	33	31	36
Other Renewables	9	9	10	10	9	10	10	10
Other	17	14	19	17	12	12	19	13
CO2 Allowance Price ($/ton)	0.0	67.0	0.0	0.0	64.8	65.4	0.0	63.1
Cumulative CO2 Emissions Reductions (M tons)	0	58,035	2,998	858	58,095	58,154	5,395	58,210
Electricity Sector	0	25,617	2,998	858	26,804	26,738	5,395	27,500
Rest of Economy	0	3,462	0	0	3,299	3,326	0	3,206
Offsets	0	28,956	0	0	27,991	28,090	0	27,504
REC Price ($/MWh)	0.0	0.0	24.3	0.0	9.5	0.0	15.3	0.0

Table 6. National Results in 2020 for noACP and High Nuclear Cost Scenarios

	RPS_noACP	RPS_noACP+TC	CTP+RPS_noACP	CTP+RPS_noACP+TC	CTP@N30	CTP+RPS@N30	CTP+TC@N30	CTP+RPS+TC@N30
Electricity Price ($/MWh)	90.8	87.8	102.8	98.8	104.7	104.9	101.6	99.3
Electricity Consumption (TWh)	4,032	4,080	3,804	3,856	3,762	3,759	3,811	3,839
Electricity Generation (TWh)	4,268	4,321	4,022	4,078	3,982	3,977	4,032	4,063
Coal	1,891	1,898	1,630	1,641	1,733	1,708	1,731	1,636
Natural Gas	439	478	512	542	758	671	700	564
Nuclear	848	848	864	872	861	848	848	848
Hydro	256	258	255	256	256	256	256	256
Renewables	808	811	761	768	374	495	497	759
Wind	553	604	563	620	272	379	389	610
Biomass	196	150	141	90	51	59	53	91
Other Renewables	59	57	58	58	51	56	56	58
Other	26	28	0	0	0	0	0	0
Capacity (GW)	1,078	1,098	1,022	1,042	944	964	975	1,045
Coal	285	282	246	249	252	249	252	246
Natural Gas	372	382	365	369	383	375	380	381
Nuclear	107	107	109	110	108	107	107	107
Hydro	96	96	96	96	96	96	96	96
Renewables	203	214	196	208	92	126	128	206
Wind	163	181	164	184	76	107	110	182
Biomass	30	23	22	14	8	9	8	14
Other Renewables	10	10	10	10	9	10	10	10
Other	17	18	11	11	13	12	13	10
CO2 Allowance Price ($/ton)	0.0	0.0	19.4	19.3	22.5	21.4	21.5	20.1
Cumulative CO2 Emissions Reductions (M tons)	1,751	1,565	8,658	8,524	9,285	9,062	8,919	8,912
Electricity Sector	1,751	1,565	5,767	5,670	5,053	5,325	5,154	5,762
Rest of Economy	0	0	504	502	584	556	558	521
Offsets	0	0	2,386	2,352	3,647	3,181	3,207	2,629
REC Price ($/MWh)	88.9	37.3	67.0	29.3	0.0	24.3	0.0	24.3

Table 7. National Results in 2035 for noACP and High Nuclear Cost Scenarios

	RPS_noACP	RPS_noACP+TC	CTP+RPS_noACP	CTP+RPS_noACP+TC	CTP@N30	CTP+RPS@N30	CTP+TC@N30	CTP+RPS+TC@N30
Electricity Price ($/MWh)	105.1	101.6	124.9	120.1	125.9	126.4	121.9	121.6
Electricity Consumption (TWh)	4,524	4,607	4,134	4,228	4,118	4,117	4,200	4,204
Electricity Generation (TWh)	4,782	4,871	4,362	4,467	4,351	4,343	4,438	4,441
Coal	1,940	1,958	613	341	788	754	409	404
Natural Gas	780	832	760	718	813	844	782	791
Nuclear	874	874	1,901	1,881	1,884	1,666	1,626	1,540
Hydro	255	255	255	256	255	255	255	256
Renewables	905	923	833	1,271	611	823	1,366	1,451
Wind	641	667	645	1,000	473	622	1,076	1,143
Biomass	203	197	129	211	86	143	231	249
Other Renewables	60	59	59	59	53	58	59	59
Other	28	30	0	0	0	0	0	0
Capacity (GW)	1,199	1,220	1,106	1,207	1,066	1,095	1,221	1,236
Coal	283	283	157	125	158	161	125	131
Natural Gas	468	478	385	390	406	404	415	410
Nuclear	107	107	237	234	235	207	202	191
Hydro	96	96	96	96	96	96	96	96
Renewables	230	239	223	352	159	217	372	398
Wind	189	199	189	305	133	181	324	347
Biomass	31	30	24	37	16	26	38	42
Other Renewables	10	10	10	10	9	10	10	10
Other	16	17	9	11	13	12	12	10
CO2 Allowance Price ($/ton)	0.0	0.0	62.3	61.8	72.4	68.1	67.5	64.6
Cumulative CO2 Emissions Reductions (M tons)	7,458	6,669	58,121	58,039	58,104	58,232	58,101	58,094
Electricity Sector	7,458	6,669	27,483	27,524	24,378	25,568	25,431	26,746
Rest of Economy	0	0	3,184	3,167	3,694	3,504	3,502	3,293
Offsets	0	0	27,454	27,348	30,033	29,160	29,168	28,055
REC Price ($/MWh)	32.3	11.7	6.4	0.0	0.0	5.6	0.0	0.0