BACKGROUNDER

June 2010; revised October 2010

Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity

Karen Palmer, Richard Sweeney, and Maura Allaire

1616 P St. NW
Washington, DC 20036
202-328-5000 www.rff.org

RESOURCES FOR THE FUTURE

NEPI National Energy Policy Institute

Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity

Karen Palmer, Richard Sweeney, and Maura Allaire

Executive Summary

The two primary motivations for energy policy in the United States are promoting energy security and combating climate change. Because the electricity sector accounts for roughly 40 percent of national carbon dioxide (CO_2) emissions, renewable sources of electricity could be particularly important for addressing this latter concern about climate change. However, renewables are typically more expensive than fossil-fueled electricity sources such as coal, which supplies nearly 50 percent of our electricity today; as a result, renewables are not economic absent policy intervention. Moreover, most renewable sources of electricity, such as wind and solar, must be exploited in the sometimes-remote locations where they are found, and they are not dispatchable—that is, they cannot produce more electricity when demand is high and less when demand is low. This latter feature limits their flexibility in helping to match electricity supply with hourly fluctuations in electricity demand.

To promote technological learning, clean generation, and economic development, a number of states have imposed policies—including renewable portfolio standards (RPSs) and tax incentives—to promote development of renewables. The federal government has continued to extend a production tax credit for wind power and other technologies as well as an investment tax credit for solar power. Given the size of the climate challenge, greater reliance on renewables likely will be necessary to make a major dent in U.S. CO_2 emissions.

Using the National Energy Modeling System (NEMS-RFF), this analysis considers the following policies to promote renewable and low-carbon sources of electricity:

- a 25 percent RPS;
- a 25 percent clean energy portfolio standard (CEPS) that includes a broader range of low-emitting technologies (with new natural gas (CEPS-NG) and without new natural gas (CEPS) included in the mix);
- a CO_2 cap-and-trade policy modeled after the cap-and-trade title of H.R. 2454, the American Clean Energy and Security Act;
- a 25 percent RPS combined with a carbon cap-and-trade policy and a CO_2 tax;

- a more aggressive clean energy portfolio standard (CEPS-All) that seeks to replicate the total share of electricity produced by technologies other than coal-fired boilers obtained under the cap-and-trade policy, which is substantially higher than the 25 percent requirement in several other policies;
- an aggressive pair of portfolio standards for generation from renewables and from new natural gas plants (RINGPS) that sums to 45 percent; and
- a policy to extend the federal production and investment tax credits for renewables indefinitely into the future.

These latter two policies receive limited treatment in the body of the report because they are very costly and the extended tax credit scenario is not very effective in reducing CO_2.

The results confirm that none of the policies aimed at promoting clean energy has a big effect on total petroleum use over this time horizon. The cap-and-trade policies produce somewhat larger reductions, on the order of 3 billion barrels of oil (2 percent of total petroleum use in the baseline) over the 2010–2030 time horizon at a present discounted welfare cost per barrel ranging from $45 to $46.[1]

Among the central technology policies that do not include a price on CO_2, the CEPS-All policy has the biggest effect on cumulative CO_2 emissions, reducing them by more than 7.6 billion metric tons or 6.1 percent over the 2010–2030 time horizon. The second-most effective policy at reducing CO_2 emissions is the RPS, which reduces emissions by nearly 3.5 billion metric tons or 2.8 percent over the 21-year horizon. The CEPS and CEPS-NG policies result in 2.9 and 2.7 billion metric tons, respectively, of the cumulative CO_2 emissions reductions.

Comparing the policies' cost-effectiveness shows that at $11 per metric ton, the CEPS-NG has the lowest average cost of all the policies that do not explicitly price CO_2; however, it produces only 35 percent of the cumulative emissions reductions of the CEPS-All at an average cost that is 73 percent of the CEPS-All average cost. The RPS and CEPS policies have comparable average costs to the CEPS-All but substantially lower effectiveness at reducing emissions. Note that the RINGPS is nearly as effective as the CEPS-All at reducing CO_2 emissions but at an average cost that is more than 1.5 times as high.

---

[1] However, the cap-and-trade policies achieve reductions in cumulative petroleum comparable to several of the oil-reduction policies modeled in another volume in this study, such as a Pavley CAFE and high feebate. The Pavley CAFE policy is based on California CAFE targets, adopted by the Pavley bill, to be implemented after 2016. The policy would increase federal CAFE standards 3.7 percent per year for 2017 to 2020, and 2.5 percent per year 2021 to 2030. The high feebate policy imposes a fee on manufacturers for vehicles with low fuel economy and offers a rebate for fuel-efficient vehicles. The feebate rates are set to achieve comparable fuel economy outcomes to the Pavley CAFE policy. The high feebate rate initially is $2,000 per 0.01 gallons/mile, and is phased in between 2017 and 2021. After 2021, the rate increases 2.5 percent a year, to reach $2,969 per 0.01 gallons/mile in 2030. The central cap-and-trade scenario results in a 3.1 billion barrel reduction over the 2010–2030 simulation period compared to the baseline, while Pavley CAFE and high feebate policies achieve reductions of 3.6 and 3.5 billion barrels, respectively (Small 2010). However, the oil reduction policies are much more cost-effective, having a present discounted welfare cost per barrel of $12.30 and $12.10, respectively (Small 2010).

The policies that include the central cap-and-trade program (or an analogous tax on CO_2 emissions) all yield substantially higher reductions in cumulative CO_2 emissions, on the order of 12.4 billion metric tons, at an average cost ($12 per metric ton) that is more than 20 percent less than that of the CEPS-All. Combining a cap-and-trade program with an RPS yields a slight increase in the average cost of emissions reductions while it produces no effect on emissions because of the cap. Combining an RPS with a carbon tax, however, yields more than 700 million metric tons of additional cumulative CO_2 reductions over the time horizon.

The policies that impose floors on renewable or clean generation are typically less cost-effective than the cap-and-trade approach for several reasons:

- They are limited to the electricity sector and thus may encourage socially inefficient fuel switching away from electricity to other sources of energy.
- In most cases, they do not discriminate among the more and less carbon-intensive fossil technologies that renewables or other non- or low-emitting technologies are likely to displace. As a result, they have a limited effect on the use of coal-fired generation.
- In some cases, they single out a particular group of zero- or low-carbon technologies that may not be the least-cost package of options for reducing emissions.
- They generally do not have a large effect on electricity price and thus provide inadequate incentives for electricity conservation.
- They give "credits" toward meeting the minimum generation floor to renewable and new clean generation that occurs in the baseline and thus does not contribute to emissions reductions. This is especially true for the more flexible standards.

Making the generation floor policy more flexible by expanding the set of eligible technologies, but holding the 25 percent goal fixed, tends to lower the effect of the policy on CO_2 emissions without raising the cost. On the other hand, increasing the share of generation that must come from clean energy, including renewables, tends to increase the CO_2 emissions reductions and the average cost of the policy.

The inclusion of an RPS (also known as a renewable energy standard or RES) in H.R. 2454 suggests that this type of policy may become part of a federal CO_2 cap-and-trade law.[2] Combining these two policies will have no effect on overall CO_2 emissions; however, if the RPS floor is binding, it will lower the price of CO_2 allowances and could raise the overall cost of the policy. Also, if the cap-and-trade policy includes a safety valve or ceiling on the price of allowances, then adding an RPS policy to the mix

[2] Note that the draft climate bill introduced in May 2010 by Senators John Kerry (D-MA) and Joe Lieberman (R-CT), does not include a clean energy portfolio standard or an RPS. However, S. 3464, introduced by Senator Dick Lugar (R-IN) in June 2010 aims to reduce CO_2 emissions not through a cap-and-trade program or CO_2 tax, but instead by clean energy sources, including renewables, and promotion of energy efficiency.

could reduce the likelihood that the allowance price cap will be triggered. Combining a cap-and-trade policy with an RPS could be justified on the grounds of market failures related to research and development or adoption of new technologies and learning by doing, but the magnitude of these externalities is not well understood and is a subject of some controversy.

An alternate way to control CO_2 and add some predictability regarding the cost of the policy is to use a carbon tax. When CO_2 is subject to a tax instead of a cap, policies that increase use of renewables could result in incremental emissions reductions. Adding an RPS to a CO_2 tax policy with tax levels analogous to allowance prices resulting with the central cap-and-trade case yields small incremental reductions in emissions of CO_2.

Important areas for additional research remain. The nature, size, and variability across technologies of externalities associated with research and development and learning by doing are not well understood. The costs of dealing with intermittency of wind and solar and the challenges associated with siting and building the transmission necessary to bring electricity from the renewable sources to market are also uncertain. In addition, the electricity price distortions created by electric-utility regulation and average cost pricing may be compounded or reduced by the various policies analyzed here, and these policy interactions need further analysis. Designing efficient policies to address these challenges will require a better understanding of the nature and extent of these potential market failures as well as how effective different policies might be in addressing them.

This background paper is one in a series developed as part of the Resources for the Future and National Energy Policy Institute project entitled "Toward a New National Energy Policy: Assessing the Options." This project was made possible through the support of the George Kaiser Family Foundation.

Contents

Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity

Karen Palmer, Richard Sweeney, and Maura Allaire*

1. Introduction

The two primary motivations for energy policy in the United States are promoting energy security and combating climate change. Given the many ways we use energy and the different forms in which it is delivered, a host of technologies and fuel options likely will play a role in addressing these concerns. Renewable sources of electricity could be particularly important for addressing climate change.

The electricity sector is a major contributor of greenhouse gas emissions in the United States, accounting for 40 percent of national carbon dioxide (CO_2) emissions in 2008. Currently, roughly 50 percent of the electricity consumed in this country is produced using coal, the most CO_2-intensive fossil fuel. Renewable sources of electricity generally do not emit CO_2 and thus could be used to mitigate climate change. However, renewables are typically more expensive than coal and other fossil-fueled electricity sources and are not economic absent policy intervention. Moreover, most renewable sources of electricity, such as wind and solar, must be exploited in the sometimes-remote locations where they are found, and they are not dispatchable—that is, they cannot produce more electricity when demand is high and less when demand is low. This feature limits their flexibility in helping to match electricity supply with hourly fluctuations in electricity demand. Transforming our electricity system to a low-carbon structure will require major changes in how and where we produce electricity.

Coal's current dominance as a generation fuel follows from its low cost relative to other sources of energy, its flexibility to be dispatched when needed, and the fact that certain environmental externalities, such as the cost of CO_2 emissions, are not fully taken into account in private decisions about electricity supply. Its dominance may also result from other market failures, such as the inability of private investors to capture the social benefits of research and

* Karen Palmer is the Darius Gaskins Senior Fellow at Resources for the Future; Richard Sweeney is a graduate student at Harvard University's Kennedy School, and Maura Allaire is a graduate student at University of North Carolina at Chapel Hill. The authors wish to thank David McLaughlin for research assistance with this paper and Kristin Hayes, Mary Haddican, Ian Parry, Margaret Walls and Alan Krupnick for helpful comments.

development (R&D) or technological learning that may be contributing to the difficulties that renewable sources of electricity are having in penetrating the marketplace.[1]

The purpose of this report is to evaluate the effectiveness and cost-effectiveness of policy options to promote renewable energy and other low-carbon sources of electric power using NEMS-RFF[2]. Because petroleum plays such a minor role in the U.S. electricity supply, the focus of this analysis largely will be on the climate benefits of these policies. The report begins with an overview of the different renewable technologies available for producing electricity, the various issues that inhibit greater use of renewables for electricity generation, and policies currently in place. Section 2 describes how renewable technologies for electricity generation are treated in the NEMS-RFF model, and section 3 reviews the different policy options that have been proposed or adopted in the states or in other countries to address the renewables issue. In section 4, we discuss why none of the renewable-technology assumptions in NEMS-RFF were adjusted for purposes of this project, and in section 5, we describe the results of the NEMS-RFF simulation. Section 6 reviews the qualitative and unmodeled aspects of the policies, and section 7 concludes.

1.1 Renewables Technology Background

In 2008—the most recent year for which data is available—the United States had 939 gigawatts (GW) of summer electricity capacity (EIA 2010). Of that, 109 GW (12 percent) was from renewable sources. However, the overwhelming majority of renewable capacity, 77 GW, comes from conventional hydroelectric power.[3] Non-hydro renewables (which we will refer to simply as "renewable energy" from this point forward) contributed 32 GW of capacity. Looking at generation, which is arguably the more relevant metric, net electric power generation in 2008

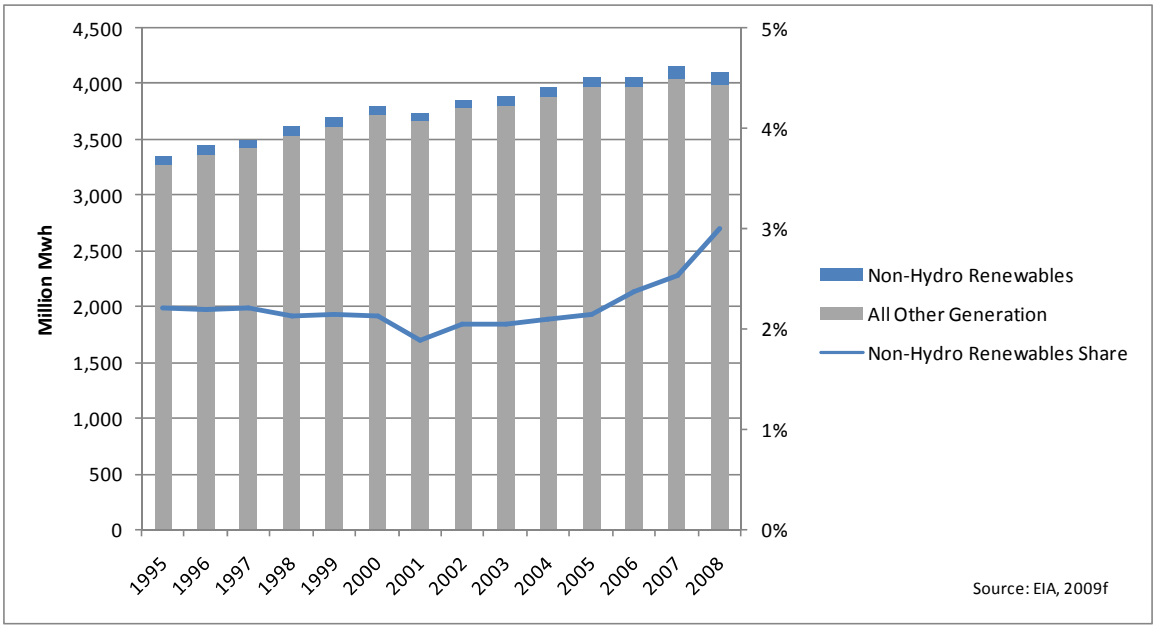
[1] A greater reliance on domestic renewable sources of electricity may also be associated with energy security benefits, although the fact that very little electricity comes from oil means that the benefits from reduced oil consumption are likely to be small.

[2] The National Energy Modeling System (NEMS) is a computer-based, energy-economy market equilibrium modeling system for the United States developed by the U.S. Department of Energy. NEMS-RFF is a version of NEMS developed by Resources for the Future (RFF) in cooperation with OnLocation, Inc.

[3] Though an important component of America's electricity system, conventional hydropower capacity is essentially exhausted because damming larger rivers raises many environmental concerns. Thus, new hydropower development is not included for the remainder of this report; instead, we focus solely on non-hydro renewable energy. Note that it remains an open question if practical limits on new hydropower development would be overcome in the presence of a high price on CO_2 emissions.

was 4,110 billion kilowatt hours (BkWh). Non-hydro renewables contributed 124 BkWh, or 3 percent. Figure 1 shows how these two statistics have evolved since 1995. Figure 2 breaks these figures down by component in 2008. In this section, we describe each individual technology briefly and conclude with a discussion of how the technologies compare in terms of cost and other performance characteristics.[4]

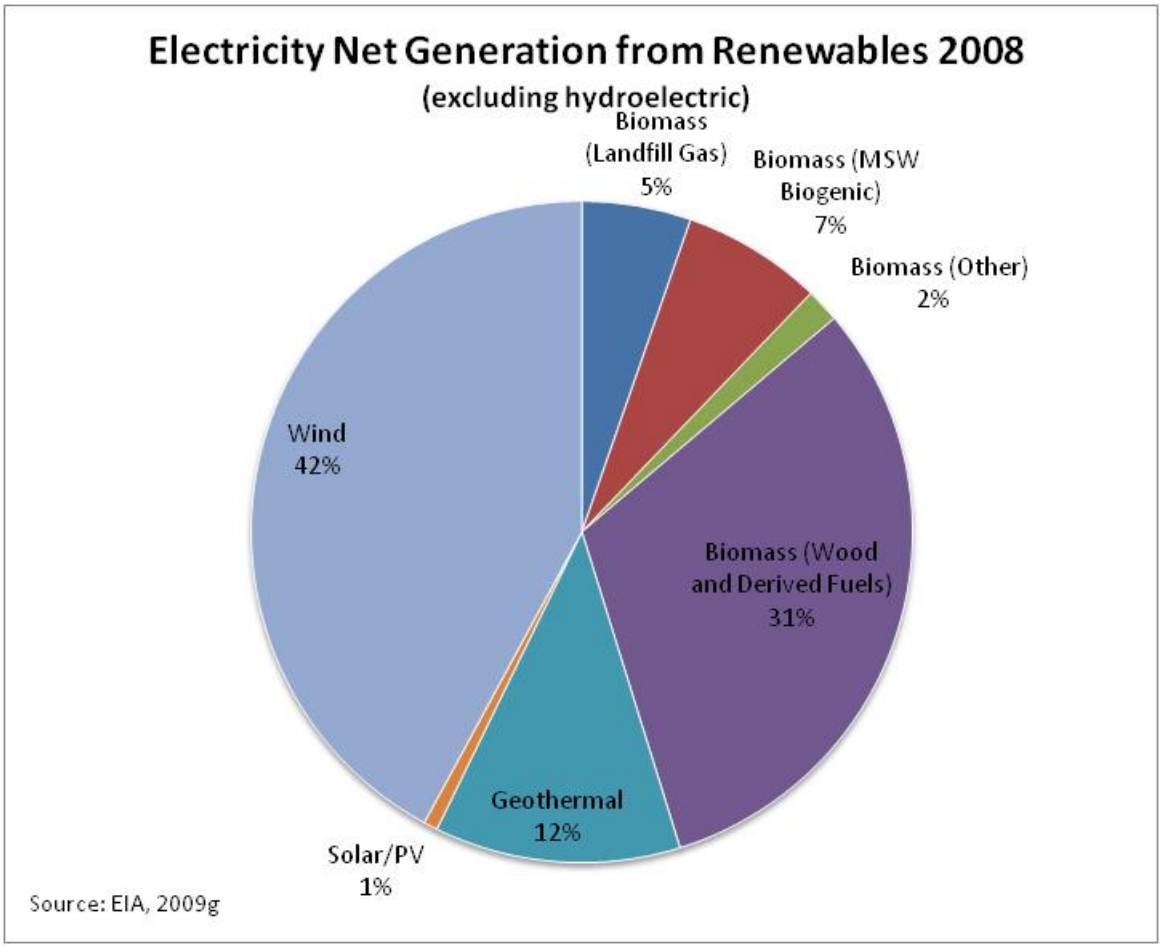
Figure 1. Non-Hydro Renewable Generation Compared to Total Net Generation



Note: MWh=megawatt hours.

[4] For a more detailed discussion of these renewable resources and the associated generating technologies, see NRC 2009. The renewable technologies included here are the ones that are currently at (or near) the commercial stage of development. Other nascent renewable technologies, such as ocean tidal or enhanced geothermal power, are not included.

Figure 2. Net Generation of from Non-hydro Renewables 2008



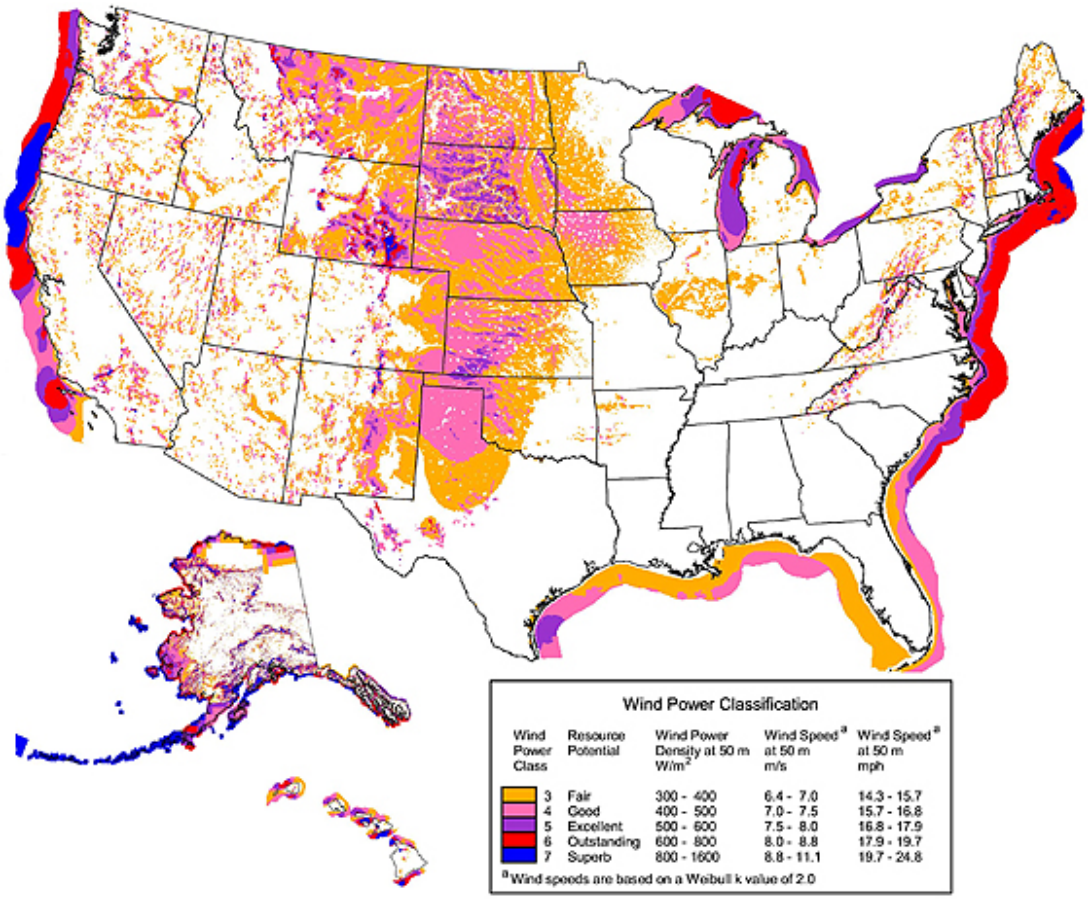
Notes: MSW=municipal solid waste; PV=photovoltaics.

Wind

Wind power uses turbines to harness kinetic energy from wind and convert it into electricity. The availability and intensity of the wind resource varies considerably across the country, as shown in Figure 3. Wind generators can only supply electricity when the wind is blowing, and the amount of energy they generate will depend on the intensity and persistence of the wind resource in a particular region, with capacity factors of new facilities expected to vary between 30 percent and 46 percent depending on the intensity of the resource. Wind is not dispatchable, and often the periods of most intense wind availability—nighttime in many regions—do not correspond to the periods of peak electricity demand. Thus, the contributions of wind generators to generating capacity can be much smaller than their average contribution to generation. The National Research Council (NRC 2009) estimates that the total amount of

extractable wind power from land-based wind facilities is about 2.2 million GW hours (GWh) per year, which equals roughly half of the total electricity generated in the United States in 2008. The NRC estimates that adding in offshore sources of wind adds another 1.6 million GWh per year of generation, which is roughly 40 percent of total electricity generated in 2007. Wind energy is the fastest-growing source of energy in the country, contributing 42 percent of all new generating capacity (8,500 megawatts, or MW) in 2008 (American Wind Energy Association 2009).

Figure 3. U.S. Wind Resources Map (measured at 50 Meters)



Notes: W/m^2=watt per square meter; m/s=meters per second; mph=miles per hour.
Source: NREL.

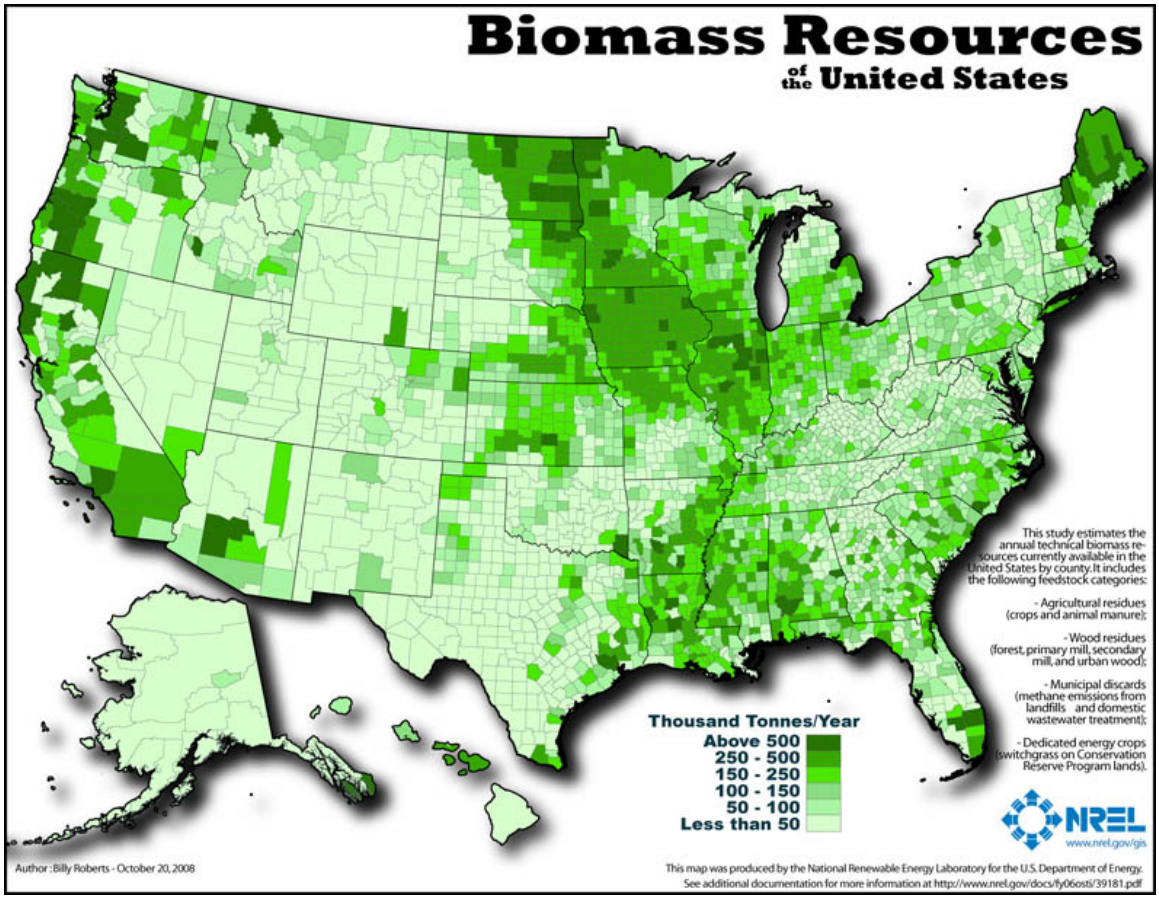
Biopower

Biopower is the use of biomass to generate electricity.[5] Technologies can include direct firing, co-firing at a coal plant, or gasification. Biopower has similar ability to be dispatched and capacity factor to a coal-fired boiler, making it a potential renewable substitute for coal. However, biomass feedstocks are often limited or costly. Sources of fuel for biopower include agricultural residues, wood residues, municipal waste, and dedicated energy crops, and the liquid fuels sector will compete for these feedstocks, particularly from the latter category.[6] The National Renewable Energy Laboratory map of available biomass resources, shown in Figure 4, reveals that the biomass is largely concentrated in the Northern Plains, Heartland, and Southeast. Biomass co-firing is technologically limited to 15–20 percent of fuel input and can involve costly boiler retrofits and cleaning. National statistics on current levels of biomass co-firing at coal plants are not available, but it appears to be very rare. Most existing biomass generation happens at industrial facilities that have a ready source of fuel, such as a pulp and paper mill or a wood products company, and most of the electricity that they generate is for their own use.

[5] We adopt the term "biopower" from NRC 2009.

[6] Biopower can also be generated capturing and processing the methane that is produced as organic material decays in landfills or by using anaerobic digestion to transform animal or human waste into methane, which is used to power a gas turbine or combined cycle generator, and usable compost.

Figure 4. Map of Biomass Resources



Geothermal

Geothermal energy captures heat from the Earth to power generators and produce electricity. Geothermal resources include underground reservoirs of steam, hot water, and hot dry rocks. The most economic form currently is hydrothermal geothermal, which makes use of large volumes of water trapped in permeable rock at depths to 11,000 feet and with temperatures above 100°C (EIA 2009d). Hydrothermal technology has a capacity factor in the 90 percent range and is a very reliable source of power. However, this resource is geographically concentrated in the western states, Alaska, and Hawaii. A 2006 National Renewable Energy Laboratory study (Green and Nix 2006) estimates that 30 GW of shallow hydrothermal resources could be developed across the United States.

Enhanced geothermal resources are in theory more widespread geographically but involve drilling of deep wells that could be several kilometers deep to access hot dry rock. A

study done by MIT (2006) suggests that substantial heat is available, but given the large depths, there are serious challenges associated with assessing the size of that resource and exploiting it. In addition, the water requirements and potential for induced seismic activity are not well understood (NRC 2009).

Solar Photovoltaic

Solar photovoltaics (PVs) use semiconductor materials to convert both direct and diffuse sunlight directly into electricity. PVs get their name because the process converts photons into voltage (National Renewable Energy Laboratory n.d.). Most traditional PV cells are made from silicon, although recent innovations in thin-film cells also use other materials, including cadmium telluride. Because it can convert energy from indirect sunlight, solar PV is ideally suited for smaller, distributed generation. However, despite dramatic declines in cost over the past few decades, PV is currently a relatively inefficient means of energy conversion and is the most costly renewable source of electricity included in this study. The NRC (2009) estimates that total national potential electricity supply from rooftop-distributed PV could range from 2 to 5 times the level of total national electricity consumption of roughly 4.1 GWh in 2005.

Solar Thermal Power

Solar thermal plants use mirrors to concentrate the sun's energy onto collectors that in turn heat water to make steam to turn a steam turbine. The three main solar thermal power technologies are parabolic troughs, power towers, and dish-Stirling engine systems (parabolic dishes). Concentrating solar power (CSP) systems require large amounts of insolation and thus will produce the highest amount of energy in regions of the country that have large amounts of direct normal solar radiation (such as the Southwest). Many systems have the capability to store energy for up to 12 hours, making solar thermal more reliable than wind or solar PV. However, these systems are costly and take up large spaces such that they are likely to be placed in the desert. There, the sunlight is abundant and land is inexpensive, but transmission is scarce, and thus substantial investment in new transmission would be needed to transport the electricity supplied to load centers. According to the NRC (2009), the total amount of potential generation from solar CSP is between 4 and almost 8 times the total amount of electricity demand in 2005 of 4.1 GWh.

1.2 Issues for Renewables

The technology descriptions above suggest several challenges associated with the various renewable energy technologies. These challenges in turn help explain renewable energy's minor

role in America's electric power market and will have to be overcome if renewable energy is going to increase substantially its contribution to electricity supply in the future. Each challenge is discussed below.

Generation Cost

The main determinant of a technology's market share in electricity generation is its relative cost. Table 1 shows capital and operating costs and associated levelized cost of energy for each generation option included in the NEMS-RFF model under the baseline scenario.[7] Note that the levelized costs are a model output instead of a model input because they depend on the price of fuel, the amount of total installed capacity of a particular type of technology (and the associated effects of technological learning), and the extent to which the model has exhausted low-cost wind generation sources and inexpensive sources of biomass. Aside from biopower, renewable energy is characterized by high fixed capital costs and low variable costs.[8] Though this capital intensity leads to less variability in costs, and therefore in profits, once the technology is in place, it means that relatively more capital is needed up front, per kW, to get a renewable project off the ground.

Renewables are also more costly because unlike fossil fuels, which can be shipped to generators, wind, solar and geothermal resources are natural phenomena specific to a particular geographic location. These resources are also not evenly distributed throughout the country, and, importantly, their distribution does not coincide well with the distribution of electricity demand or with the location of existing transmission infrastructure. Thus, getting renewable electric power to consumers involves not just the standard capital and operating costs, but also the costs of transmission to connect to the grid and, with high levels of renewable development, to expand the grid to accommodate greater volume of long-distance electricity transmission (Vajjhala et al. 2008). Expanding transmission capacity raises a host of issues, including potential disruption of natural habitat and wild areas and the need to gain acceptance for siting of lengthy transmission corridors from the multiple state and federal agencies that may have jurisdiction over territory crossed by a long-distance transmission line. Dealing with siting issues can raise the cost of

[7] This table focuses on 2012 because that is the first year when most new facilities can be added, given construction lead times.

[8] The fixed costs of onshore wind are not high, but given the low capacity factor of these facilities, the levelized costs are higher than for baseload coal and gas-fired plants.

increasing transmission capacity and the amount of time required between the recognized demand for new transmission facilities and when those facilities are available for use.

Table 1. Technological Characteristics and Levelized Costs of New Generating Technologies

Technology	Size (mW)[b]	Leadtime (years)[b]	Total Overnight Cost in 2008 (2007 $/kW)[b]	Variable O&M ($2007 mills/kWh)[b]	Fixed O&M ($2007/kW)[b]	Heatrate nth-of-a-kind (Btu/kWh)[b]	National Levelized Cost ($2008 per MWh)[c, d]
Scrubbed Coal	600	4	2058	4.59	27.53	8740	83.2
Integrated Coal-Gasification Combined Cycle (IGCC)	550	4	2378	2.92	38.67	7450	100.5
IGCC with Carbon Sequestration	380	4	3496	4.44	46.12	8307	116.8
Conventional Gas/Oil Combined Cycle (CC)	250	3	962	2.07	12.48	6800	92.8
Advanced CC	400	3	948	2	11.7	6333	88.1
Conventional Combustion Turbine (CT)	160	2	670	3.57	12.11	10450	154.2
Advanced CT	230	2	634	3.17	10.53	8550	136.2
Nuclear	1350	6	3318	0.49	90.02	10434	102.2
Biopower	80	4	3766	6.71	64.45	7765	99.4
Geothermal	50	4	1711	0	164.64	30301	87.1
Wind	50	3	1923	0	30.3	9919	101.5
Offshore Wind	100	4	3851	0	89.48	9919	171.1
Solar Thermal	100	3	5021	0	56.78	9919	191.6
Solar Photovoltaic	5	2	6038	0	11.68	9919	303.2

[a] Online Years: 2012 or sooner except IGCC with CCS: 2016, Adv CC with CCS: 2016, Nuclear: 2016

[b] Source: EIA 2009. Table 8.2 from Assumptions to the Annual Energy Outlook 2009. DOE/EIA-0554

[c] Source: OnLocation, Incorporated

[d] 2012, except: Coal: 2026, IGCC with CCS: 2016, Conv CC: 2021, Adv CC: 2018, Nuclear: 2017, Offshore Wind: 2014

Notes: MW=megawatts; kW=kilowatts; O&M=operation and maintenance; btu=British thermal unit; kWh=kilowatt hours; MWh=megawatt hours.

Intermittency/Reliability

Wind and solar energy are plagued by a lack of predictability in their inputs, which translates into intermittency of electricity supply. This is evidenced by their relatively low capacity factor compared to geothermal, biopower, or a coal-fired boiler. The electricity grid is a finely balanced system, and due to the prohibitively high cost of most forms of electricity storage, grid operators have to manage the operation of generators connected to the system in a way that balances electricity demand and supply in real time. Adding increasing amounts of

intermittent resources to the system will increase the challenge of meeting this goal and may increase demand for back-up generation that can be called in quickly in case of a sudden and unexpected loss of generation. In the event that supply fails to meet demand, there is a risk of a limited or extensive system blackout, which would have widespread costs (Brennan et al. 2002; Stoft 2002). The NRC (2009) concludes that grid integration costs for wind, the most economic of the intermittent technologies, are likely to be less than 15 percent of total costs if wind supplies 20 percent or less of total electricity generation.

To ensure sufficient generating capacity to meet peak levels of demand, the regional transmission organizations and other system operators typically require load-serving entities to have arrangements with capacity providers to supply capacity in excess of the total needed to meet peak demand. The amount of excess capacity, referred to as a reserve margin, varies from location to location, but a typical level is between 12 and 15 percent (Stoft 2002). Since wind and, to a lesser extent, solar, are intermittent, and wind, in particular, typically has a peak-demand-period capacity factor that falls well below its average capacity factor, operators discount their average level of available capacity when calculating their contribution to the necessary reserve.

Environmental Externalities

One reason renewable electricity appears more costly than electricity produced using fossil fuels is that the external costs associated with fossil generation are not fully accounted for in private decisions of utilities and grid operators. Chief among these external costs is the cost of CO_2 emissions from burning fossil fuels, which are not currently priced for U.S. generators, except for those in the Northeast states participating in the Regional Greenhouse Gas Initiative.[9] Renewable generators do not emit CO_2 during the generation process and thus avoid this cost. Imposing a policy that places a price on CO_2 emissions would help to close the gap in costs between fossil and renewable technologies identified above.

Other environmental externalities also bias electricity generation resource choices. Fossil generators emit a variety of air pollutants including sulfur dioxide, nitrogen oxides, and mercury. While most of these are regulated to some extent, regulations may be set at levels that fail to

[9] The price of Regional Greenhouse Gas Initiative allowances is below the social cost of carbon estimates currently under consideration by the federal government for use in regulatory impact analyses (Interagency Working Group on Social Cost of Carbon 2010)

fully internalize costs (Banzhaf et al. 2004), so an increase in regulatory stringency, such as tightening the Title IV sulfur dioxide cap, could improve the relative cost picture for renewables. In addition, most generators—including coal-boilers and other fossil units, nuclear, and even some renewables (such as CSP, geothermal, and biomass)—use water for cooling purposes. If generators do not pay the full opportunity cost of those water resources, an uninternalized externality may exist there as well. While the size of the water externality is likely to be small compared to those for air pollution and to vary across the country, pricing water fully may serve to improve the relative cost position of wind relative to most other sources of electricity.

Energy Security Concerns

Renewable energy is also more secure than some fossil fuels; however, because only a very small portion of electricity in the United States (roughly 1 percent in 2008) is produced using oil, the energy security benefit of producing more electricity with renewables is likely small. The size of the energy security benefit of more renewable generation in the future depends on what the marginal source of natural gas generation is likely to be. If, as expected up until very recently, the United States would need to become more reliant on imports of liquefied natural gas to meet growing demand from the electricity sector, then anticipated growth in use of natural gas to supply electricity could add to energy security concerns, particularly given that two-thirds of the world's natural gas reserves are found in Russia, Iran, Qatar, the United Arab Emirates, and Saudi Arabia (Schmitt 2006). If increased natural-gas generation meant growing reliance on imports from these countries, then increasing the share of renewables generation at the expense of natural gas could yield important energy security benefits. However, recent technological advances in horizontal drilling and hydraulic fracturing (Navigant 2008) that enable the extraction of natural gas from vast reservoirs in shale formations indicate that natural gas will be in sufficient supply to meet domestic demand for some time to come, even with increased use from the electricity sector. According to the Potential Gas Committee (2009), estimates of total natural-gas supply increased by 25 percent between the 2008 and 2006 assessments, and one-third of total potential resources comes from shale gas plays, illustrating the importance of this new resource.[10]

[10] For analysis of how the enhanced gas supply that might be enabled by these developments would influence the efficacy and cost-effectiveness of different policies to reduce CO_2 emissions, see Brown et al. 2009.

R&D and Learning by Doing

The cost gap between renewables and other sources of generation could potentially be reduced through both R&D and learning by doing.[11] However, well-recognized externalities associated with each create a gap between private and public incentives to pursue these cost-reducing activities (Jaffe et al. 2005). With regard to R&D, the benefits from successful research to improve existing renewable technologies typically spread beyond those who bear the costs of the research, and thus private firms have an insufficient incentive to invest in R&D. With regard to technology adoption, potential social benefits from more widespread adoption of a new technology due to learning by doing, learning by using, and network externalities can drive a wedge between socially optimal levels of technology adoption and what occurs in private markets.

Fischer and Newell (2008) analyze the literature on the effects of knowledge accumulation through the combination of learning from experience with a technology and learning from R&D and find that for a 10 percent increase in accumulated knowledge stock with respect to a particular type of renewable, capital costs are assumed to fall by 3 percent. They then model the optimal policies for addressing a CO_2 externality and the inability to appropriate the effects of learning and R&D expenditure on aggregate costs. They find that the optimal subsidy for renewables production to internalize the learning externality is about 0.3 cents per kWh (or 4 percent of the electricity price), which is substantially less than the typical subsidy associated with a renewables tax credit or renewables quota policy such as an RPS.

1.3 Current Policies to Promote Renewables

In the United States, Europe, and other parts of the globe, governments have implemented a number of different policies to promote renewables. Typically these policies either subsidize the cost of generating with renewables or increase the demand for renewable generation. In some cases, policies provide for additional sources of revenue for renewable

[11] Whether learning by doing or R&D will be the more fruitful path for achieving costs reductions is subject to controversy. For example, in the case of solar PV, Borenstein (2008a, 2008b) argues that learning by doing has no case as a route to achieving cost reductions and that cost reductions in the past are more likely the results of technical innovations resulting from more traditional R&D. Nemet (2006) uses an engineering economics model to look at the role of various factors that contributed to the dramatic decline in the cost of PV technology between 1980 and 2001 and finds learning from experience plays a limited role in explaining this decline in cost. On the other hand, Surek (2005) finds that costs of new PV modules have declined dramatically with increases in production.

generators, such as through the sale of renewable energy credits, or seek to create a private retail market for renewable electricity itself.

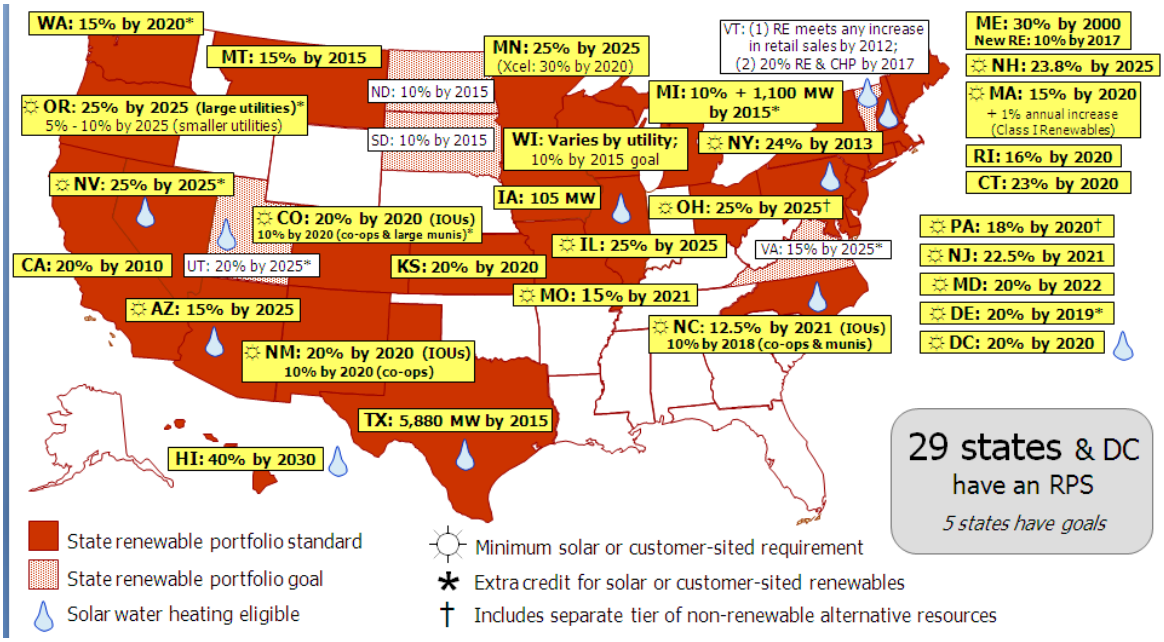
In the United States, the main policies used to promote renewables are tax credits and accelerated depreciation. The tax credits for renewables can take the form of either a production tax credit or an investment tax credit. For new generators brought online between 2009 and the relevant expiration date, the policy provides a 2.1 cent tax credit for wind, geothermal, and closed loop biomass and a 1.1 cent tax credit 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 until it expires on December 31, 2012, for wind and December 31, 2013, for all other eligible technologies. Typically Congress has approved this policy, which initially passed in 1992, for one to two years into the future, and it has lapsed three times since its inception. 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 and 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 extends the deadlines on the production tax credit but also allows investors with limited expected tax liability to substitute a grant for the tax credit and generators to elect a 30 percent investment tax credit rather than the production tax credit. While 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.

A more popular policy at the state level is the renewable portfolio standard, which requires that a minimum amount of electricity generated or sold in the state be produced using eligible renewable technologies. As shown in Figure 5, as of August 2009, 29 states had RPSs.[12] 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. Some states include technologies other than renewables, such as waste coal and fuel cells, in the portfolio standard. 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. Renewable owners and operators then sell these RECs to utilities, who are required to purchase some predefined number of RECs for every megawatt hour (MWh) of power they sell. Some states cap the price of RECs, effectively removing the

[12] See http://www.dsireusa.org for more information about federal and state policies to promote renewables (accessed June 18, 2010).

floor by allowing generators to purchase unlimited RECs at the price cap (also known as an alternative compliance payment). Thus, the effect of an RPS on the economics of renewable generation will depend on the specific features of the policy design.

Figure 5. State Renewable Portfolio Standards



Source: http://dsireusa.org (August 2009).

An RPS addresses several current barriers to renewable energy adoption. First, it generates an additional revenue stream for renewable owners. This reduces the average net cost of investing in a new renewable generator, making them more competitive with fossil generation. Second, an RPS provides a long-term signal to investors that demand will be sufficient for renewable electricity for many years to come, regardless of what happens in coal or natural gas markets. Members of Congress have put forth numerous proposals for a federal RPS, and a renewable portfolio standard of 15 percent by 2020 is incorporated in Title I of the American Clean Energy and Security Act, which the House of Representatives passed in June 2009.

In addition to or instead of the RPS, states have several other types of policies to promote renewables. As of August 2009, 42 states have 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 backwards when a distributed renewable generator produces more electricity than it requires for its own consumption. Some states also have their own tax incentives for renewables as well as rebate and loan programs.

Another strategy used to promote renewable electricity production is green power marketing. Typically the term "green power" is used to refer to all types of renewables except new hydropower electricity facilities. Green power marketing focuses on marketing power from new but not yet existing facilities. Green power marketing to customers can occur in competitive electricity markets or as an optional tariffed service that regulated utilities offer customers who choose to purchase this type of service. According to researchers at the National Renewable Energy Laboratory, in 2008, green power products were available in 45 states and the District of Columbia (Bird et al. 2008), voluntary purchases of green power totaled roughly 18.1 billion kWh in 2007, and almost 90 percent of this electricity was generated by non-hydro renewables (Bird et al. 2007).[13]

In Europe, a popular policy for promoting renewable electricity production is to specify a minimum price that utilities must pay generators for renewable electricity; this price is known as a feed-in tariff. Currently, roughly 18 European countries, including Spain and Germany, have such a policy (NRC 2009), along with a few U.S. states (California, Vermont, and Washington), some of which were still refining their policy at the time of this writing.[14] The specifics of the European feed-in tariffs vary across countries and technologies, and are generally calculated to achieve profitability of the targeted technology. Thus high-cost technologies, such as solar PV, typically have higher feed-in tariffs than lower cost technologies, such as wind. Feed-in tariffs are typically guaranteed for a certain amount of time and thus lower the profit risk to renewable generators. However, Spain recently had to reduce the size of its feed-in tariff quite dramatically to keep from bankrupting the program (Voosen 2009).

2. Representation of Renewable Technologies in NEMS-RFF

Renewable-generating technologies that are used for commercial grid–scale generation are captured in the Renewable Fuels Module of the National Energy Modeling System (EIA 2009d). The technologies included in this module of NEMS-RFF are those described above in section 1.1, plus landfill gas and conventional hydropower. Electricity generated by distributed

[13] How much of this power is additional to what would have been generated in the absence of a green power market is an important unknown, and there is definitely potential for overlap between voluntary green power marketing and renewable requirements under state RPS policies (Bird and Lockey 2007).

[14] See http://www.dsireusa.org for more information on state-level feed-in tariff regulations in the United States (accessed June 18, 2010).

solar PV and distributed wind is included in the residential and commercial energy–demand modules of NEMS-RFF.

2.1 Technology Representation

The representation of renewable technologies in NEMS-RFF varies across the different technologies but typically includes measures of upfront capital cost, construction lags, fixed and variable operating and maintenance costs, capacity factors, and resource constraints. For wind and solar, the amount of resource and the capacity factor depend on the quality of the resource in a particular location and at particular times. For geothermal electric generation, the resource is limited to very specific sites, primarily in the western United States.[15] For biomass, the amount of energy supply depends on the availability of biomass fuel sources within a particular region, and biomass fuel supply is a function of the market price of the fuel.

2.2 Technological Learning

Each technology also has a learning function that allows for the upfront capital cost of adding new capacity to decline with the passage of time and as a function of cumulative capacity installations. Learning functions are steepest for the more nascent technologies like solar PV and CSP, which results in greater potential for cost declines, while they are flat for more mature technologies. In NEMS-RFF, wind is classified as a relatively mature technology and thus sees little in the way of cost declines due to experiential learning from more capacity installation. On the other hand, the integrated gasification combined cycle (IGCC) technology that is assumed for new biomass generation facilities has a fairly steep learning curve. Learning curves for wind-turbine capacity factors allow for these to increase with higher levels of wind power development up to some predetermined limit for each wind class. While adding more capacity has a positive effect on capacity-factor learning, it could have a negative effect on realized capacity factors because it raises the probability that wind generation will have to be curtailed during peak periods due to total system generation exceeding load during periods of low demand. This possibility is also accounted for in the NEMS-RFF model and will affect actual

[15] This type of geographic limitation does not hold for geothermal heat pumps, which take advantage of stable underground temperatures to provide space heating and cooling.

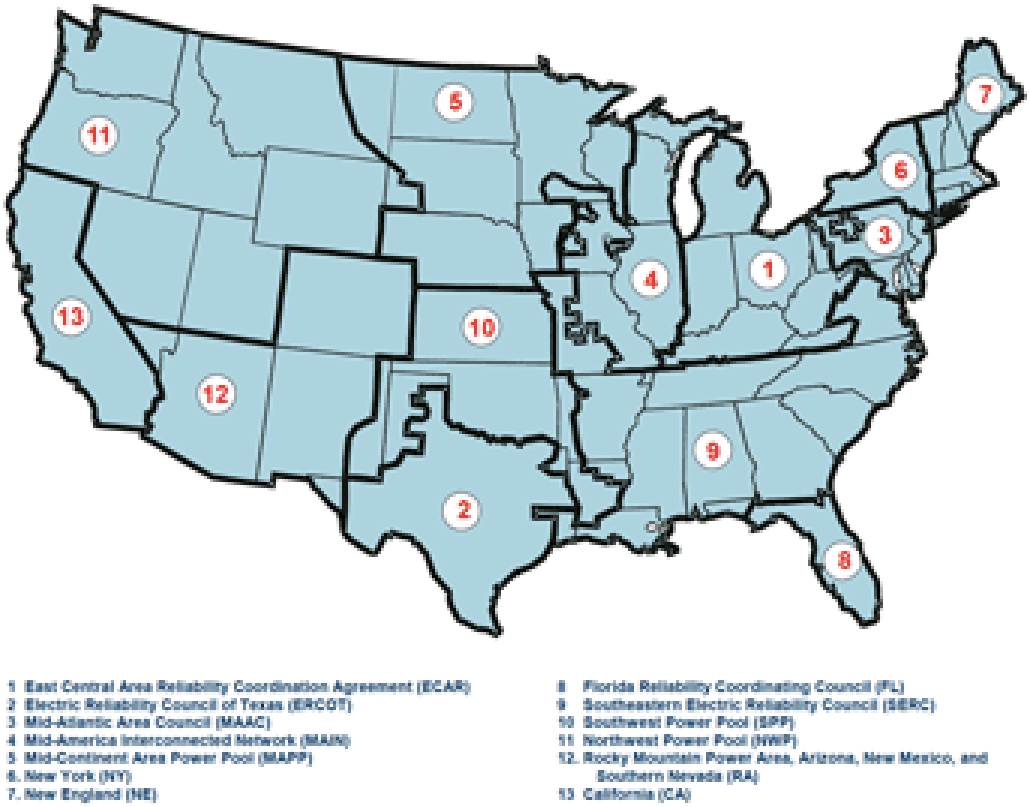
capacity factors in the future if and when wind generation capacity becomes abundant in certain regions.[16]

2.3 Geographic Representation of Wind, Solar, and Geothermal Technologies

Within the NEMS-RFF model, all information about location of electricity generators is ultimately represented at the Electricity Market Module (EMM) region level, and NEMS-RFF divides the continental United States into 13 regions, which largely overlap with the historical North American Electricity Reliability Corporation electricity reliability areas (or subregions). The NEMS-RFF EMM regions are shown in Figure 6. However, within these large regions is typically a fair amount of heterogeneity in the quality of solar or wind resources, the accessibility of the sites where the resources are located, and their proximity to the transmission grid. Within each region, land that is not available for wind development is excluded from the resource calculation. Such lands include all protected parks and wilderness areas, land with greater than 20 percent slope, public lands where wind development is precluded, urban areas, wetlands, and airports. For some types of land areas, like forested ridge lands, only 50 percent of the land mass is assumed to be available for wind development.

[16] For more information see EIA 2009d, section 3.

Figure 6. NEMS-RFF Electricity Market Module Regions



Source: EIA 2009a.

For wind, the resource base is "binned" according to wind speed as defined by the wind class in a particular portion of the NEMS-RFF region, the cost of accessing the sites on land (or in the ocean) necessary to exploit the wind and the costs of the additional transmission investment necessary to bring the generated electricity in the area to the load centers. Further, potential wind supply is disaggregated by certain time slices as generation potential varies over the course of the day and year. This classification results in a stepped wind supply curve for each region. Note that NEMS-RFF only includes the power available from developments in areas in the three highest wind classes. The size of a typical wind development (or wind farm) assumed

in NEMS-RFF is 50 MW consisting of 50 1 MW turbines of onshore development and 100 MW consisting of 50 2 MW turbines for offshore development.[17]

The two solar technologies included in NEMS-RFF are distinguished by scale and the type of solar resource that they require. Concentrating solar power requires direct sunlight at high levels of insolation and therefore cost-effective development is limited to areas in the U.S. West, particularly the desert areas of the Southwest. The NEMS-RFF model includes one of the three major CSP technologies: a 100 MW power tower with 6 hours of storage capacity in Molten Salt. The availability of CSP facilities is limited at night and on cloudy days, which vary in frequency across seasons, and thus this technology has different availability factors by season and for day versus night. Solar PVs can make use of diffuse sunlight and thus have a much broader potential geographic development, although capacity factors will vary with the degree of insolation. The PV technology represented in NEMS-RFF is a 5 MW fixed flat-plate crystalline silicon single-axis tracking array tilted at an angle equal to the site's latitude. For distributed PV, the size of the system is measured in kW instead of MW and installation potential is limited by the estimated amount of appropriately oriented rooftops on commercial and residential buildings (EIA 2009b, 2009c).

In NEMS-RFF, the geothermal resource for electricity generation is limited to hydrothermal resources potentially available at a number of sites in the U.S. West identified by the U.S. Geological Survey (Muffler 1978) and modified by subsequent studies by the Western Governors Association (2006) and the California Energy Commission (GeothermEx 2006). The NEMS-RFF model does not include any characterization of generating potential or costs for hot dry rock or other enhanced geothermal applications consistent with the assumption that these technologies will not be commercially available prior to 2030. The model currently incorporates 88 existing and potential sites. Each potential site is characterized by a capital cost, maximum capacity, heat rate, operating and maintenance costs, and capacity factor; these site-level

[17] Larger installations are assumed for offshore facilities to assure sufficient economies of scale to justify higher development, installation, and maintenance costs.

estimates are merged to form a geothermal supply curve for each of the relevant NEMS-RFF regions.[18]

2.4 Biomass Technology and Fuels

The NEMS-RFF model includes two technologies for converting biomass to electricity: a stand-alone IGCC technology and co-firing of biomass with coal, which is subject to a limit of 15 percent of total generator fuel input. Unlike wind, solar, and geothermal, biomass technologies require a fuel input—sources of wood waste and agricultural crops grown specifically for fuel. The amounts of these resources are quantified by region, and transportation costs (within an assumed limited radius that depends on the fuel type) are an important component of the fuel cost. The electricity sector must compete with demands from the liquid fuels sector (ethanol) for use of much of the biomass fuel source, and in NEMS-RFF, the higher-quality fuel is typically diverted to cellulosic ethanol production. Thus the price of biomass fuels to electricity generators are typically lower than those to refiners.

2.5 Inability to Account for Uncertainty

An important limitation of the NEMS-RFF model that is particularly relevant for intermittent technologies like renewables is its inability to represent uncertainty. In NEMS-RFF, the future is assumed to be known with certainty, so when firms make investment decisions, they know what fuel prices and interest rates will be, how much their generation facility will be available to operate, and what prices they will get for their electricity. In reality, a great deal of uncertainty surrounds these factors, and some technologies may introduce more uncertainty than others. These factors, which clearly play a role in firm decisionmaking, are not represented in NEMS-RFF or in most large energy sector models. So, for example, the effects of different investment paths on the variance of profits does not matter, and the model imposes no penalty for actions that could contribute to short-term system instability even though this is important to actual system operations.

[18] The number of potential sites for hydrothermal geothermal development is potentially in excess of those currently included in NEMS-RFF; however, the cost and performance data estimates necessary for running the NEMS-RFF model only exist for a subset of all sites. Note that the geothermal data in EIA 2009d is likely to be updated soon based on new information forthcoming from resource studies under way in the Department of Energy Office of Energy Efficiency and Renewable Energy. If the cost of developing sites that are currently excluded from the NEMS-RFF model is less than those that included, it could impose an upward bias on the cost of renewables policies reported here.

3. Policy Options

The set of potential policy instruments for promoting renewables draws largely from the existing policies identified above in section 1.3. In the main body of this analysis, we focus on one type of policy to promote renewables and other low-carbon sources of electricity generation: portfolio standards that impose a floor on the percentage of renewables and broader categories of clean generation with the creation of tradable credits in each case. We also consider a CO_2 cap-and-trade policy as well as scenarios that combine a carbon policy in the forms of cap-and-trade and an emissions tax with a renewable portfolio standard. Each policy is described in more detail below. Two additional policy options also receive some attention. First, because Congress has renewed the production and investment tax credits for renewables several times in the past, we also consider a scenario in which these tax credit policies are extended at current levels indefinitely into the future. Second, we look at a policy that combines the RPS described below with a separate minimum requirement for generation from new natural gas facilities. These two additional policies, marginal due to high cost and, in the former case, low efficacy, are described in later sections of the report.

3.1 A CO_2 Cap-and-Trade System

The central cap-and-trade policy scenario is based on the cap-and-trade provisions found in Title VII of the American Clean Energy and Security Act, sponsored by Representatives Henry Waxman (D-CA) and Edward Markey (D-MA), that passed the House of Representatives in June 2009. This policy scenario limits the total number of offsets that can be used to 1 billion tons, roughly half the limit specified in the bill, and divides that limit between a 500-million-ton limit on offsets from domestic sources and a 500-million-ton limit from international sources. By placing a cap on CO_2, the bill creates an opportunity cost for emissions of this byproduct of generation with fossil fuels and helps to reduce the gap in costs between generation with fossil and renewables. As a result, this policy should lead to an increase in renewables generation relative to a baseline scenario.[19]

However, a carbon policy might not be sufficient to yield the efficient level of generation from renewable sources for several reasons. For example a recent study by researchers at

[19] The policy also improves the cost-competitiveness of nuclear generation; however, siting and other impediments to the construction of new nuclear plants might limit the total amount of new nuclear capacity in the next 20 years. In recognition of these factors, we limit the total amount of new nuclear generation capacity that could be constructed over the next 20 years to 50 GW.

Carnegie Mellon University suggests that a politically feasible carbon emissions cap will yield a permit price that might not be sufficient to promote investment in renewable energy, which will ultimately be necessary to achieve substantial emissions reductions (Samaras et al. 2009). Also, as discussed in section 1.2 above, several potential market failures lead to underinvestment in renewables R&D—especially in relatively nascent technology, potential for learning by doing, and public goods problems with transmission, and pricing carbon will only address one market failure. However, policies targeting the other market failures, whether it be expanding transmission or promoting renewables research, have the potential to reduce the economic burden of an economy-wide cap-and-trade program further down the line.

3.2 Renewable Portfolio Standard (RPS)

The second scenario we analyze is an RPS policy consistent with the one originally proposed by Senator Bingaman in an earlier stand-alone RPS proposal (and largely incorporated into the renewables title in the original draft of H.R. 2454, although it was ultimately made less stringent as a result of legislative negotiations). This scenario calls for 25 percent minimum generation by non-hydro renewables nationwide by 2025 with interim targets leading up to this ultimate goal.[20] This policy allows trading of renewable energy credits and includes a $50 per MWh cap on REC price that grows at the rate of inflation. It is expected to reduce CO_2 emissions in the absence of a cap; however, past research suggests that it would be more costly than a cap-and-trade program (Palmer and Burtraw 2005; Fischer and Newell 2008). This policy scenario likely represents the outer limits of a federal minimum standard for renewables generation that the U.S. Congress might pass because it is more stringent than any requirement ever voted out of committee.[21]

Given the popularity of this type of policy with advocates, the fact that members of Congress have proposed in legislation in several past sessions and are actively debating it

[20] Under this policy, the 25 percent goal applies to retail sales of electricity and excludes generation from existing hydropower or municipal solid waste incinerators from both the numerator and the denominator, as specified in most federal RPS proposals. So the total generation to which the standard is applied is total electricity retail sales minus generation from hydro and existing municipal solid waste plants. As a result, when fully implemented and assuming that the price cap on RECs is not binding, the policy will lead to roughly 23.5 percent of total retail sales being generated by eligible renewables and a slightly lower percentage of total electricity generation including distributed generation.

[21] Unlike the federal RPS included in the American Clean Energy and Security Act, this policy does not include a provision that some portion of the RPS can be satisfied with energy-efficiency credits.

currently, and the fact that over half of the states have renewable portfolio standards in effect, the RPS is an important policy to analyze as a part of this project. Prior analysis of the Markey RPS proposal by the U.S. Energy Information Administration (EIA) suggests that it will reduce CO_2 emissions from the electricity sector in 2020 by 4 percent below baseline levels and in 2030 by 12 percent below baseline levels. We run this policy in conjunction with the baseline scenario and with both the central cap-and-trade case and a carbon tax scaled to the allowance price in the central cap-and-trade case.

A carbon cap as specified in the central cap-and-trade scenario would not only set a ceiling on CO_2 emissions, it would also set a floor. Thus, if an RPS is enacted on top of a CO_2 cap-and-trade system, the additional renewables will not reduce overall carbon emissions. The extra renewables mandated will drive down the demand for CO_2 allowances and thus their price. Also, it is possible that mandating scale will pull the market toward the optimal level of scale, learning, and innovation, which it cannot otherwise achieve because of other market failures. When central cap-and-trade is modeled as an emissions tax instead of a cap, adding an RPS is expected to lead to additional reductions in CO_2 emissions. How many additional reductions and at what cost are important empirical questions addressed by this analysis.

3.3 Clean Energy Portfolio Standard

This policy expands the set of technologies included in the portfolio beyond non-hydro renewables to also include incremental generation from nuclear power plants and generation from natural gas and coal plants with carbon capture and storage (CCS) capability. Under this scenario, generation from new nuclear power plants and all eligible renewable technologies will receive one credit per MWh generated, and generation by the two types of plants with CCS will receive alpha credits per MWh generated where alpha=(1-(emissions rate for technology T/emissions rate for coal boiler)). Note that alpha is defined to reflect the difference in emissions rate relative to a new pulverized coal boiler and is equal to 0.9 for IGCC coal with CCS and 0.95 for a natural gas combined-cycle plant with CCS. Under this policy, we model the same minimum requirement for this collection of eligible generators as we required for renewables under the RPS policy (25 percent by 2025) but with an expanded set of eligible generation types. This policy also includes the same $50 per MWh cap on the clean energy credit (CEC) price as the earlier RPS policy. In an earlier analysis, EIA found that a CEPS of 20 percent by 2025 reduced CO_2 emissions from the electricity sector by roughly 5.5 percent in 2020. As a result, the one we are modeling might be expected to yield reductions in the 7–9 percent range by 2020, although this is a bit difficult to predict given changes in the baseline and in fuel price

assumptions since EIA did its earlier analysis (EIA 2006, 2007a). This scenario is run in conjunction with the baseline only.

The downside of CEPS is that nuclear and CCS generation may be less desirable or technologically feasible than renewable energy. Nuclear power poses significant challenges with respect to siting and waste storage. For these and other reasons, no new nuclear plants have been built the United States for three decades (MIT 2003, 2009). CCS, on the other hand, is a nascent technology. In addition to the costliness of capturing and storing carbon, concerns are considerable that emissions will not remain sequestered.

The CEPS policy is similar in many ways to a policy recently proposed by Senator Lindsey Graham (R-SC) in a draft piece of legislation not formally introduced as of this writing. The Graham policy titled the "Clean Energy Act of 2009" sets a minimum standard for generation from clean energy sources of 13 percent in 2012 phasing to 50 percent in 2050 with a standard of 25 percent from 2025 through 2029 and growing to 30 percent in 2030. This policy includes incremental generation from nuclear plants and generation from coal with CCS that captures a minimum of 65 percent of the CO_2 emissions in its definition of clean energy as well as the suite of renewable resources modeled here. Like the CEPS that we model, it also includes discounting credits offered for units that use CCS related to the emissions reductions produced by the CCS and a 5 cent per kWh alternative compliance payment that effectively caps the price of CECs. Unlike the CEPS that we model, it includes credits for energy savings associated with energy-efficiency investments that could be used to comply with up to 25 percent of the clean energy standard, and it also awards partial credits for avoided generation from coal plants with average CO_2 emission rates in excess of 2,500 pounds per MWh that retire by a certain date. In addition, this policy allows for CEC banking, a feature we do not model. The draft energy bill S. 3464 introduced in June 2010 by Senator Dick Lugar (R-IN) also includes a CEPS that is similar to the one included in Senator Graham's bill, except that it includes no limit on the contribution from energy efficiency and a different mechanism for providing incentives for the retirement of older coal plants. It also projects higher levels of the CEPS past 2030.

3.4 Clean Energy Portfolio Standard with Natural Gas

An expanded version of the CEPS specified above includes incremental generation from natural gas with the other technologies that are eligible for CEPS credits. In this scenario, which we refer to as CEPS-NG, generation by new natural gas capacity receives a fraction of a CEC for each MWh generated by a natural gas–fired generator. Similar to the assignment of credits to technologies that incorporate CCS under the CEPS as described above, the fraction of a credit

(denoted by alpha) that a MWh of generation by an eligible gas generator receives depends on how its emissions rate compares to that of a new coal boiler. The portion of a CEC earned by a natural gas generator depends on the technology. There four types of new natural gas generators included in the model and their share of credits are:

- advanced natural gas combined cycle (.59),
- conventional natural gas combined cycled (.56),
- advanced natural gas turbine (.37), and
- conventional natural gas turbine (.33).

Under this policy, the path of clean energy–generation targets is the same as under the CEPS policy (hitting 25 percent by 2025), and the $50 per MWh price cap on clean energy credits also applies. This scenario is run in combination with the baseline scenario only.

3.4 Expanded Clean Energy Portfolio Standard

A third CEPS scenario seeks to replicate the total share of generation from all non-coal-fired technologies (with the exception of coal with CCS) that is obtained under a central CO_2 cap-and-trade policy. The mechanism for doing this is an expanded CEPS (CEPS–All) that creates one category of "clean" generation that includes generation from both new and existing non-coal generators. Unlike the two other CEPS scenarios, the basis for this run is all utility electricity sales and generation by all renewables (including hydro-electric and municipal solid waste incineration) will be included in both the basis and the "clean energy" requirement.

The policy works by requiring each electricity seller to demonstrate that it holds CECs equal to a minimum percentage of electricity sales. CECs are associated with the generation of electricity by any technologies except pulverized coal boilers or IGCC without CCS. Credits are assigned based on the relative emissions rate of each "clean" technology compared to a new pulverized coal boiler. Unlike in the CEPS and CEPS-NG scenarios, there is no cap on the price of CECs.

The assignment of credits to generation by each technology is based on the average value of 1-(the CO_2 emissions rate of each technology divided by the CO_2 emissions rate of a pulverized coal plant). For all renewable technologies (including hydro and municipal solid waste) and for nuclear power, the credit rate is 1. For the other technologies the credit assignment rates per kWh are as follows:

- advanced natural gas combined cycle (.59),

- conventional natural gas combined cycled (.56),
- advanced natural gas turbine (.37),
- conventional natural gas turbine (.33)
- gas/oil steam turbine (.13),
- IGCC with CCS (.90), and
- advanced natural gas combined cycle with CCS (.95).

Because partial credit is assigned to technologies that emit some amount of CO_2, the total amount of credits required per MWh of electricity sold will be less than the total share of clean energy under the cap-and-trade policy, which this CEPS-All policy is trying to replicate. The minimum standards or shares for the collective set of clean technologies is derived to be consistent with the amount of electricity produced by each technology in the "clean energy" group under the central cap-and-trade case in each year and the credit assignments to each technology type listed above. So, for example, if electricity under the cap-and-trade policy were produced by 30 percent coal, 30 percent gas combined cycles, 20 percent renewables, and 20 percent nuclear, then the clean energy share would be .7 and the total CEPS-All credit requirement would be (.3*.56)+(.2*1)+(.2*1) = .568. The clean energy share and associated credit requirements for each year between 2012 and 2030 are listed in Table 2.

Table 2. Credit Requirements for CEPS-All Scenario

Year	Clean energy share of total electricity sales in central cap-and-trade scenario	CEPS-All credit requirement
2012	.52	.46
2013	.54	.47
2014	.54	.48
2015	.55	.49
2016	.56	.49
2017	.56	.50
2018	.57	.50
2019	.57	.51
2020	.57	.51
2021	.58	.52
2022	.59	.53
2023	.61	.54
2024	.57	.55
2025	.62	.56
2026	.64	.57
2027	.65	.58
2028	.66	.59
2029	.70	.62
2030	.73	.65

Assigning partial credits based on relative CO_2 emissions rates to those technologies that emit some amount of CO_2 serves to differentiate the subsidy side of this CEPS according to each technology's potential emissions-rate reduction compared to coal. Scaling the total credit requirement under the portfolio standard to match the total amount of credits that would be awarded under such a policy for the mix of clean generators obtained with the central cap-and-trade policy helps to assure a continued but diminishing role for coal generation similar to what occurs under cap-and-trade. However, this policy is unlikely to exactly match either the aggregate mix of coal and clean generation or the mix of various types of clean generation found under the cap-and-trade policy. This lack of exact congruency occurs because the CEPS-All policy affects the price of fuels, particularly natural gas, used by the electricity sector, and those prices in turn will affect the value of the subsidy embodied in the price of the CECs. Both factors will affect the price of electricity, which will affect electricity demand.

3.5 Other Policies Not Modeled

Most policies chosen for analysis in this study represent either extensions of current policies or policies that have been proposed at the federal level. Some policies are variants on recent proposals, all of which lend themselves to analysis with the NEMS-RFF model. However, other policies that would address existing market failures and help to increase the use of renewables to supply electricity are excluded from the study either because of political infeasibility, limitations of the NEMS-RFF model, lack of information on costs and effectiveness, or some combination of these three factors. For completeness, we briefly discuss these policies here.

Investment in R&D

Rather than pulling renewable energy innovation through the market with a price signal, another option policymakers might consider is pushing innovation by investing in R&D. Indeed government investment in renewables R&D was substantially increased under the American Recovery and Reinvestment Act of 2009, and higher levels of support than in recent years are anticipated in the next federal budget. The conceptual economic justification for these types of investments is straightforward. Spillovers and imperfect property rights make innovation markets imperfect, and this attenuation problem, where innovators are not compensated for the full value of their innovation, is more pronounced the more nascent the technology (Newell 2008a, 2008b). As mentioned, several renewable technologies classify as nascent technologies, making them strong candidates for government-subsidized R&D.

If successful, R&D can reduce the overall cost of achieving a renewable-energy or CO_2 emissions target over a long enough time horizon. If innovation makes renewable energy significantly cheaper or more efficient, it will reduce the amount of government assistance necessary to achieve a given target in the future. However, while R&D has the potential to reduce program costs in the future, the benefits are highly uncertain.

This uncertainty limits our ability to model the effects of R&D investment on the cost and performance of the different renewables technologies.

Feed-in Tariff

Federal legislation was introduced in the 110th session of Congress by Representative Jay Inslee to establish a federal feed-in tariff for renewables similar to policies proposed in Europe. Under this policy, investors sign long-term supply contracts with electricity retailers that guarantee the price they will receive for their energy. As a result, the policy reduces the price

risk that generators face relative to an RPS, where future renewable credit prices are uncertain and likely to fluctuate. The flip side of this feature is that feed-in tariffs can be very expensive if conditions change in the middle of the long-term contract. Our experience in this country with Public Utility Regulatory Policies Act contracts with qualifying facilities is a case in point. Under the act, states were required to purchase electricity from cogenerators and renewable generators at the avoided cost of electricity generation from traditional sources. Under this provision, utilities in several states made long-term contracts with cogenerators and renewable suppliers at a point in time when the costs of producing electricity from conventional sources were relatively high; ultimately, these contracts proved to be uneconomic.

The main benefits from this form of policy come from its ability to reduce uncertainty for investors; thus it would be useful to have a quantitative measure of the value of reducing uncertainty. Unfortunately, the modeling tools to look at this question are not easily at hand. Moreover, the effects of such a feed-in tariff policy could be similar to the effects of a tax credit, albeit at a much higher level than modeled here.

Transmission Expansion

As discussed above, many of America's highest-valued renewable sites remain untapped because they are isolated from the electric power grid. By subsidizing transmission expansion into areas with great renewable energy potential, the federal government could help bring the most competitive renewable resources to the market, increasing the share of renewables that will ultimately be dispatched. However, transmission expansion is expensive, and planning is plagued by bureaucratic holdups and NIMBY (Not in My Backyard) mentality. Furthermore, once power lines are built, conventional generation sources likely will benefit from the increased transmission capacity as much as renewables will. Therefore, connecting the dots between a policy to increase new transmission capacity and the resulting effects on renewables capacity and generation is a complicated exercise.

4. Discussion of Relevant NEMS-RFF Assumptions

For purposes of this analysis, we did not change any of the cost or technological performance or technological learning assumptions in the NEMS-RFF model. Instead, project resources were devoted to running a broader range of renewable and low-carbon generation policy alternatives. In this section, we discuss the rationale for not adjusting the NEMS-RFF cost assumptions and explore some ways in which the assumptions in other models used for policy analysis differ from those in NEMS-RFF.

A recent study by the NRC (2009) found that with the exception of solar, the estimates of cost for the various renewable technologies that are assumed in the NEMS-RFF model are within the range of the estimates that are found in the literature.[22] The NRC study includes tables that compare input cost assumptions and current estimates of the levelized cost of a kWh from the NEMS-RFF AEO2009 baseline with cost estimates from a variety of sources, including the Electric Power Research Institute (EPRI), National Renewable Energy Laboratory/Black and Veatch, the Department of Energy's Office of Energy Efficiency and Renewable Energy, the Western Governors' Association, Standard and Poor's, and the American Solar Energy Society, as well as other industry associations. These comparisons suggest that the NEMS-RFF estimates of the levelized cost (cost per kWh of supply) are in the middle to upper ends of the range of cost estimates found in the literature. One reason that NEMS-RFF costs may be on the high side is that unlike most comparable estimates, they reflect the run-up on material costs that occurred just prior to the recession of 2009 and had a big effect on the costs of new plants. These increases in material prices affect NEMS-RFF capital costs for all generation technologies but have the biggest effect on the delivered cost of a kWh for the capital-intensive technologies, such as wind and solar.

In the case of biomass, the EIA assumes that a fairly advanced IGCC technology will be adopted by all new facilities. The biomass technology assumed for all new dedicated biomass generation investment in NEMS-RFF is a very advanced IGCC technology that as of this writing was not being used at a commercial scale in the United States, either with biomass or with fossil fuels like coal. As represented in the model (and yet to be verified in the real world), this technology is very efficient and has high potential for learning, so costs come down rapidly with increases in installed capacity. If another technology, such as a stoker boiler, were assumed instead, this could affect the role that biomass would play in meeting a renewable portfolio standard.

One important prerequisite to bringing large amounts of wind and solar capacity into the mix of generation technologies deployed in the United States is the building of new transmission capacity between areas where the resource is located and load centers. The costs of these types of investments are included in the NEMS-RFF model, but the modelers themselves will admit that due to the large size of the NEMS-RFF model regions and the limited geographic detail of the

[22] Note that the authors of this study participated in the writing of the NRC report.

underlying sources of information on grid infrastructure, these estimates of cost are fairly crude. In its Regional Energy Deployment System (ReEDS), the National Renewable Energy Laboratory uses geographic information systems to disaggregate the electricity market into 134 balancing regions for purposes of matching supply and demand and more than 356 resource regions for purposes of characterizing wind and solar resources, costs (including costs of delivering power), and performance (Short et al. 2009). This model identifies at a much more disaggregate geographic scale than NEMS-RFF such factors as terrain and more precise distance to transmission lines that might affect installation costs and the transmission investments and associated cost of delivering power to customers that would be required. The ReEDS model also includes economic decisions regarding more general transmission upgrades between regions and more explicit assumptions regarding the anticipated evolution of wind and solar technology costs over time, which are generally independent of the amount of installed capacity. The model also generates forecasts out to 2050. Note that the EIA acknowledges that the ReEDS model does a better job of capturing the locational features of wind and solar development, but what NEMS-RFF has that ReEDS does not have is the interactions with the rest of the energy sectors in the economy. According to EIA, incorporating this level of geographic detail into NEMS-RFF would increase solution time substantially, rendering the NEMS-RFF model much less useful for the types of modeling exercises and policy analyses that it is used for (EIA 2009c). One interesting difference between NEMS-RFF and ReEDS is that NEMS-RFF typically does not predict much investment in the future in CSP, while the ReEDS model does anticipate 30 GW of solar CSP by 2030 in its baseline, largely the result of more optimistic initial cost assumptions and improvements in cost over time.

5. NEMS-RFF Results

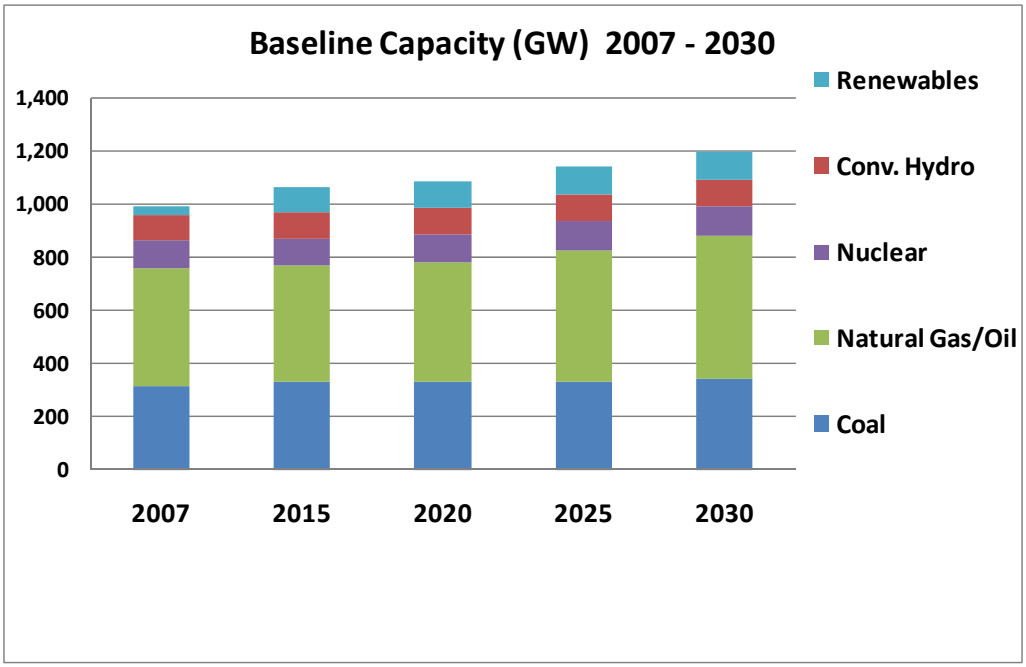
The purpose of this analysis is to study the effects and costs of several different policies to reduce CO_2 emissions and, to a lesser extent, oil use. All these policy scenarios are compared to the baseline scenario. Thus we begin our discussion of the results with a summary of the model predictions for several key electricity sector parameters for the baseline scenario. Then we present the policy comparison in terms of effectiveness in and average cost of reducing oil use and CO_2 emissions, the key metrics of interest. We follow that discussion with more detailed review of how each policy affects other aspects of the electricity markets, including price, electricity demand, capacity and generation mix, and CO_2 emissions that together determine the ultimate effectiveness and average cost results.

5.1 Baseline Scenario

We begin with a short discussion of the baseline scenario, in particular looking at how renewable capacity and generation are predicted to change over the next 20 years. We also discuss the projected evolution of CO_2 emissions with this scenario. This discussion will provide important context for the results of the different scenarios. The baseline scenario is similar to the modified AEO2009 reference case scenario that includes the effects of the American Recovery and Reinvestment Act and is used as the reference case in the EIA analysis of H.R. 2454 (EIA 2009e). The baseline scenario also includes the Obama administration CAFE rules, not included in the EIA modified reference case.

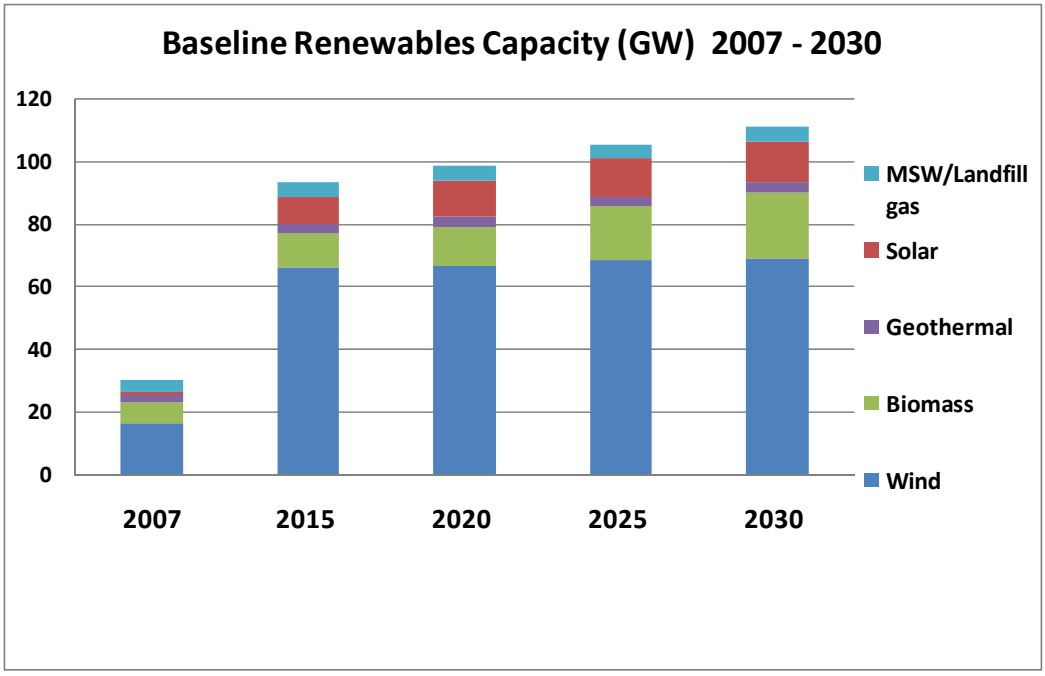
In the baseline scenario, total electricity-generating capacity is projected to increase by a little more than 20 percent between 2007 and 2030, growing from 993 GW to slightly more than 1,200 GW, as shown in Figure 7. Most of the increase comes in the form of renewables and natural gas capacity. Figure 8 shows that over the same time horizon, total renewables capacity more than triples, growing from slightly more than 30 GW in 2007 to more than 110 GW in 2030. The majority of the anticipated investment in renewables capacity is for wind turbines, which account for more than 60 percent of total renewable capacity in 2030. Solar capacity, almost all of which is PV, also increases substantially growing from slightly more than 1 GW in 2007 to more than 13 GW in 2030. Biomass capacity also more than triples between 2007 and 2030 when it tops 20 GW.

Figure 7. Generation Capacity by Fuel in the Baseline Scenario



Note: GW=gigawatts.

Figure 8. Renewable Generation Capacity by Fuel in the Baseline Scenario

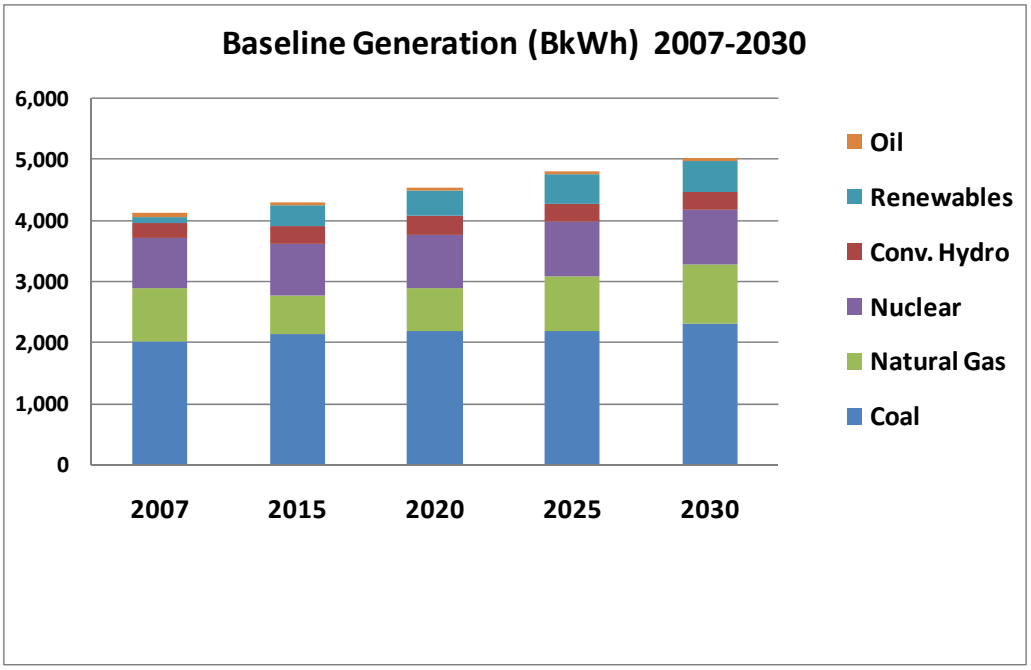


Note: GW=gigawatts; MSW=municipal solid waste.

Growth in total generation mirrors growth in capacity at about 21 percent between 2007 and 2030. Figure 9 shows that, with the exception of oil, all other sources of electricity contribute to this growth. Renewables exhibit the highest growth rate, rising from 2.5 percent of total generation in 2007 to 10 percent in 2030, when renewables produce almost 500 billion kWh of electricity. The amount of natural gas generation is lower in 2015 and 2020 than in 2007 but ultimately increases to a level that is nearly 10 percent higher than in 2007, at nearly 1,000 billion kWh.

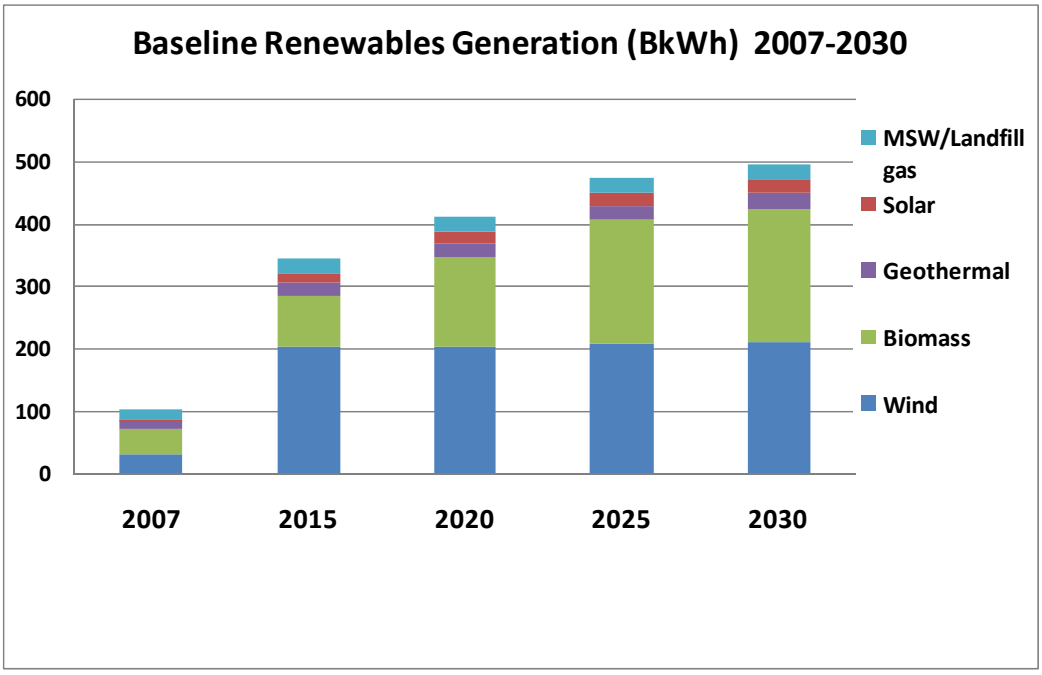
The five-fold increase in total renewables generation is illustrated in Figure 10. Consistent with the capacity increases shown in Figure 8, most of the early increase is due to increases in wind capacity, with a small portion coming from increased use of solar. After 2015, most of the increase in renewables generation comes from greater use of biomass, which ultimately accounts for roughly 40 percent of renewables generation, a share equal to that of wind in 2030.

Figure 9. Total Generation by Fuel in the Baseline Scenario



Note: BkWh=billion kilowatt hours.

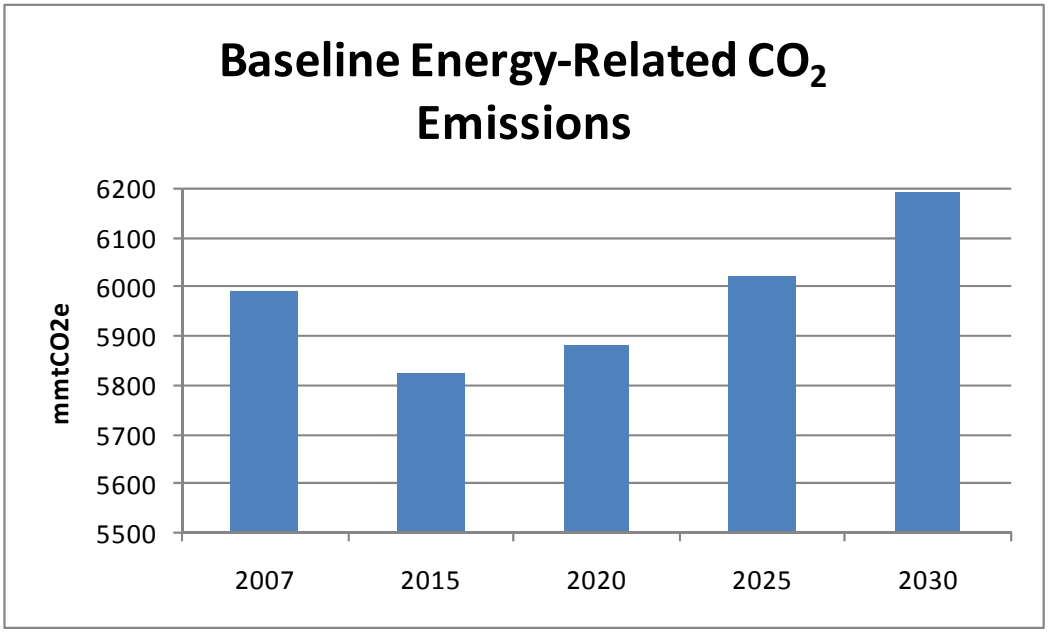
Figure 10. Total Renewables Generation by Type in the Baseline Scenario



Note: BkWh=billion kilowatt hours; MSW=municipal solid waste.

The time path for CO_2 emissions from energy consumption under the baseline scenario is shown in Figure 11. Total annual CO_2 emissions through 2020 are projected to be below levels that occurred in 2007, presumably due in part to the effects of the stimulus spending on energy efficiency and the higher CAFE standards included in this scenario. By 2025 aggregate emissions are above 2007 levels and continue to rise through 2030.

Figure 11. Energy Related CO_2 Emissions for the Baseline Scenario



Note: mmtCO2e=million metric tons of carbon dioxide equivalent.

5.2 Policy Comparison Using Key Metrics

We compare the policies in three time frames: a cumulative picture over the entire 2010–2030 time horizon and annual snapshots in 2020 and 2030. In each comparison, we measure reductions in oil imports and use as well as CO_2 and total greenhouse gas emissions. On the cost side of the ledger, we measure welfare costs as the economic deadweight loss (costs to producers and consumers) associated with each policy. Cost-effectiveness is equal to the total welfare costs divided by reductions in oil use and in total CO_2 emissions. A detailed explanation of how welfare costs are calculated for each policy scenario is presented in Appendix 1.

The most informative way to look at the cost-effectiveness is in terms of the cumulative effects over the full simulation horizon and the present discounted value of the associated stream of annualized costs. Table 3 summarizes the cumulative reductions in petroleum use and CO_2 emissions from energy under each of the seven policy scenarios relative to the baseline. The table also presents the net present value of the cumulative welfare costs and cost effectiveness measures for both petroleum reductions and emissions reductions. All costs are presented in 2007 dollars.

Table 3. Key Metrics over Entire Simulation Horizon

	2010 - 2030						
	Baseline Policy Runs				Carbon Policy Runs		
	RPS	CEPS	CEPS-ng	CEPS ALL	Cap and Trade	C&T with RPS	Carbon Tax with RPS
Key Metrics PDV (5% Discount Rate)							
Total Petroleum Reductions in million barrels (from Core 1)	448	402	79	27	3,129	3,248	3,243
Total Energy-CO_2 Emissions Reductions in mmtCO_2e (from Core 1)	3,489	2,850	2,652	7,632	12,366	12,697	13,103
Total welfare cost of policy $ billion (net present value)	$ 48	$ 40	$ 30	$ 116	$ 142	$ 151	$ 170
Average welfare cost of reducing petroleum $/barrel	$ 106	$ 100	$ 377	$ 4,385	$ 45	$ 46	$ 52
Average welfare cost of reducing CO_2, $/ton (NPV)	$ 14	$ 14	$ 11	$ 15	$ 12	$ 12	$ 13

Note: All monetary figures are in $2007

The results confirm that, as expected, none of the policies aimed at promoting clean energy has a big effect on total petroleum use over this time horizon, with cumulative reductions of well under 1 percent of total petroleum use. The cap-and-trade policies produce somewhat larger reductions, on the order of 2 percent of total petroleum use in the baseline at a present discounted cost per barrel ranging from $45 to $46.

With respect to CO_2 emissions, the results indicate that among the technology policies that do not include a price on CO_2, the CEPS-All policy has the biggest effect on cumulative CO_2 emissions, reducing them by nearly 7.6 billion metric tons or 6.1 percent over the compete time horizon. The 25 percent RPS is the second-most potent policy, reducing cumulative CO_2 emissions by nearly 3.5 billion metric tons or 2.8 percent over the 20-year time horizon.[23] The similarly scaled CEPS and CEPS-NG policies result in 37 and 35 percent, respectively, of the cumulative emissions reductions associated with the CEPS-All. When comparing the policies on cost-effectiveness grounds, we see that the CEPS-NG has the lowest average cost among the four policies that do not explicitly price CO_2. The low average cost of this policy is in part attributable to its relatively small scale, particularly compared to the CEPS-All. While it produces only 35

[23] The reductions in CO_2 emissions from an RPS identified in this study are substantially lower than those identified in EIA's earlier analysis. This is likely true for a several reasons. First, baseline emissions are lower in the baseline scenario used in this analysis than in the EIA reference used in EIA's analysis of a 25 percent RPS. Second, more existing policies to encourage renewables at the state level are included in the baseline, and thus the federal policy results in smaller increases in overall renewables generation. Third, baseline levels of electricity consumption grow at lower rates, and thus the amount of total renewable generation resulting from a particular percentage target is smaller.

percent of the cumulative emissions reductions of the CEPS-All, the CEPS-NG has an average cost that is 73 percent of that of the CEPS-All. The RPS and CEPS policies have comparable average costs to the CEPS-All, but substantially lower effectiveness at reducing emissions.

The policies that include the central cap-and-trade system (or an analogous tax on CO_2 emissions) all yield substantially higher reductions in cumulative CO_2 emissions on the order of 12.4 billion metric tons, which is 1.6 times the reductions resulting from the CEPS-All policy and 3.5 times the reductions from an RPS. (More than 87 percent of the reductions under a cap-and-trade policy occur in the electricity sector.) The average cost of these reductions is about 80 percent as large as that of the CEPS-All and 86 percent as large as the RPS.

Combining a cap-and-trade program with an RPS yields a slight increase in the average cost of emissions reductions (the change is less than $1 so not visible due to rounding) while it produces no effect on emissions because of the cap.[24] Combining an RPS with a carbon tax yields more than 700 million metric tons of additional cumulative CO_2 reductions and results in a small decrease the price of renewable energy credits in all years.

Comparing the cap-and-trade policies with the technology-promotion standards in terms of cost-effectiveness is complicated due to the differences in scale. If we assume that the marginal abatement cost of CO_2 reductions with a cap-and-trade policy is linear, then we can use the CO_2 allowance prices and associated CO_2 emissions reductions under the central cap-and-trade policy in each year to construct an approximate marginal abatement cost curve for CO_2 for that year.[25] These curves can be used to find the marginal and total cost of using a cap-and-trade approach to achieve the annual emissions reductions found under each of the other policies. We can then calculate the present discounted value of the average cost of achieving the cumulative reductions obtained under each policy if we had used a cap-and-trade approach instead. In the case of the CEPS-ALL policy, we ran the NEMS-RFF model again to represent a policy that

[24] Note that when we combined an RPS with a cap-and-trade policy, the model yields a different result for cumulative emissions reductions from the straight cap-and-trade scheme, but this is strictly a result of model convergence and not indicative of a real difference between emissions under these two scenarios.

[25] The assumption of linear marginal costs is probably overly conservative at low levels of emissions reductions. This implies that the average cost under cap-and-trade suggested in this table is likely an upper bound.

imposes a cap on emissions from the electricity sector that equals the level of emissions under the CEPS-All policy in each year.[26]

The result of these calculations is presented in Table 4 along with the emissions reductions and the average cost of each policy copied from Table 3. In every case, the implied cost of using a cap-and-trade approach to achieve the same level of CO_2 emissions reductions as obtained with the portfolio standard policy is lower than the cost of the portfolio standard approach.

Table 4. Comparison of Estimated Average Welfare Cost of Cumulative CO_2 Emissions Reductions Associated with Different Policies with Costs under a Cap-and-Trade Approach that Achieves the Same CO_2 Emissions Reductions

	RPS	CEPS	CEPS-NG	CEPS-ALL*
Cumulative emissions reductions (mmt)	3,489	2,850	2,652	7,777
Average cost with policy ($/ton)	$14	$14	$ 11	$15
Average cost with cap-and-trade ($/ton)	$4	$4	$3	$9

*The cap-and-trade equivalent of the CEPS-All policy is a true NEMS-RFF model result, whereas the other policies are interpolations based on an assumed linear marginal cost curve pegged to the cap-and-trade allowance prices under the central cap-and-trade case. The CEPS-ALL cap is modeled as a cap on electricity sector emissions only, so the emissions reductions numbers reported in this column are for the electricity sector only.

Notes: RPS=renewable portfolio standard; CEPS=clean energy portfolio standard; NG=natural gas; mmt=million metric tons.

The key metrics results for 2020 and 2030 are summarized in Tables 5 and 6, respectively. In addition to presenting the results for the baseline and each of the policy scenarios compared to the baseline, each table also includes the 2007 data as a point of comparison. Consistent with the results in Table 3, these tables show that the policies designed to encourage renewables and clean energy generation have virtually no effect on oil imports or petroleum use and that the effect of the cap-and-trade scenarios is only somewhat larger.

In terms of CO_2 emissions, the policies can be classified in two groups, with all the portfolio standards (RPS, CEPS, CEPS-NG and CEPS-All) yielding CO_2 emissions declines of

[26] Note that the calculation s in Table 4 include an approximation of the distortions from pre-existing tax policies investment tax credit and production tax credit) under each scaled cap and trade program, which is calculated by scaling the distortions under cap and trade by the fraction of emissions reductions under cap and trade achieved by each policy. For CEPS-All the distortions from the investment tax credit and production tax credit are measured directly.

between 150 and 270 million metric tons in 2020 and between 220 and 350 million metric tons in 2030, and the scenarios that include a carbon cap or tax yielding CO_2 emissions reductions of roughly 400 million metric tons (mmt) in 2020 and 1,000 mmt in 2030. Combining an RPS with a CO_2 tax produces close to 100 mmt fewer CO_2 emissions in 2030 compared to the cap-and-trade policy by itself. None of these policies has a very big effect on GDP in either year.

The cost-effectiveness results presented in Tables 5 and 6 indicate that analyzing cost-effectiveness on a yearly basis yields some anomalous results and inconsistent rankings of the policy scenarios across different years. For example the CEPS-All policy has the lowest annual average cost of CO_2 reductions of all the policies in 2020 and the highest annual average cost in 2030. Moreover, the cost-effectiveness measures for all the policies tend to vary substantially between the two years. These yearly fluctuations in cost occur because the different policies provide incentives for different types of capital investments at different points in time, and thus an annual snapshot of costs is a very incomplete assessment of the cost of the policy.[27]

[27] The change in consumer surplus tends to be very small and the change in preexisting tax distortions is also quite small compared to the effects of the renewables subsidy.

Table 5. Effectiveness and Cost-Effectiveness of Different Policies in 2020

		2020							
			Baseline Policy Runs				Carbon Policy Runs		
	2007	Baseline	RPS	CEPS	CEPS-ng	CEPS ALL	Cap and Trade	C&T with RPS	Carbon Tax with RPS
Key Metrics									
Net Imports (mmbpd)	10.00	9.34	9.33	9.33	9.33	9.28	9.11	9.13	9.11
Total Petroleum (mmbpd)	19.94	17.84	17.81	17.80	17.81	17.78	17.56	17.59	17.57
Total Energy-CO2 Emissions (mmtCO_2e)	5,991	5,883	5,704	5,758	5,735	5,612	5,384	5,388	5,376
Total GHG Emissions (mmtCO_2e)	7,282	7,383	7,207	7,261	7,237	7,114	6,658	6,665	6,650
Real GDP, $ billion (2007 $)	11,524	18,531	18,540	18,535	18,530	18,539	18,467	18,466	18,479
Total welfare cost of policy, $ million			$ 1,852	$ 1,151	$ 1,382	$ 2,383	$ 5,553	$ 5,237	$ 5,453
Average welfare cost of reducing petroleum $/barrel			$ 198	$ 94	$ 170	$ 106	$ 56	$ 59	$ 57
Average welfare cost of reducing CO_2 $/ton			$ 10	$ 9	$ 9	$ 9	$ 11	$ 11	$ 11

Note: All monetary figures are in $2007

Table 6. Effectiveness and Cost-Effectiveness of Different Policies in 2030

		2030							
			Baseline Policy Runs				Carbon Policy Runs		
	2007	Baseline	RPS	CEPS	CEPS-ng	CEPS ALL	Cap and Trade	C&T with RPS	Carbon Tax with RPS
Key Metrics									
Net Imports (mmbpd)	10.00	8.17	8.18	8.22	8.21	8.01	7.40	7.46	7.52
Total Petroleum (mmbpd)	19.94	17.99	17.83	17.89	17.98	18.05	16.94	16.92	16.93
Total Energy-CO2 Emissions (mmtCO_2e)	5,991	6,186	5,816	5,894	5,956	5,145	4,815	4,784	4,724
Total GHG Emissions (mmtCO_2e)	1,292	1,753	1,754	1,754	1,754	6,896	1,475	1,479	1,475
Real GDP, $ billion (2007 $)	11,524	23,912	23,904	23,917	23,915	23,814	23,715	23,731	23,732
Total welfare cost of policy, $ million			$ 4,736	$ 1,889	$ 1,228	$ 22,135	$ 17,482	$ 17,472	$ 19,976
Average welfare cost of reducing petroleum $/barrel			$ 81	$ 53	$ 500	$ (1,019)	$ 46	$ 45	$ 45
Average welfare cost of reducing CO_2 $/ton			$ 13	$ 6	$ 5	$ 21	$ 13	$ 12	$ 14

Note: All monetary figures are in $2007

Box 1: The Extended Production Tax Credit and Investment Tax Credit

The baseline scenario to which all policy scenarios are compared assumes that the production and investment tax credit policies currently in place phase out on schedule. However, these tax credit policies have been renewed repeatedly over the past several sessions of Congress, and there is good reason to expect that in the absence of an RPS or climate policy, they might continue to exist in some form for the indefinite future. Thus, we run an additional policy scenario that extends these two tax credit policies in their current form indefinitely into the future.

This extended tax credit scenario leads to cumulative reductions in CO_2 emissions of about 450 mmt, roughly 0.4 percent of total cumulative emissions under the baseline and only 13 percent of the reductions achieved under the RPS. This is a very small effect that is substantially smaller than that found by EIA (2007b) for a similar policy. Even though this policy produces a large increase in renewable generation capacity by 2030, it actually results in lower electricity prices than the baseline scenario and thus higher levels of electricity consumption, which limits its effectiveness in reducing emissions. Electricity price falls because some of the costs of generating with renewables are covered by the subsidy.

The total present discounted value welfare cost of this policy over the simulation horizon is $71 billion dollars, resulting in an average cost of $159 per ton, substantially above that of the other main policies analyzed here.

5.3 Detailed Results for Renewables and Clean Energy Policy Scenarios

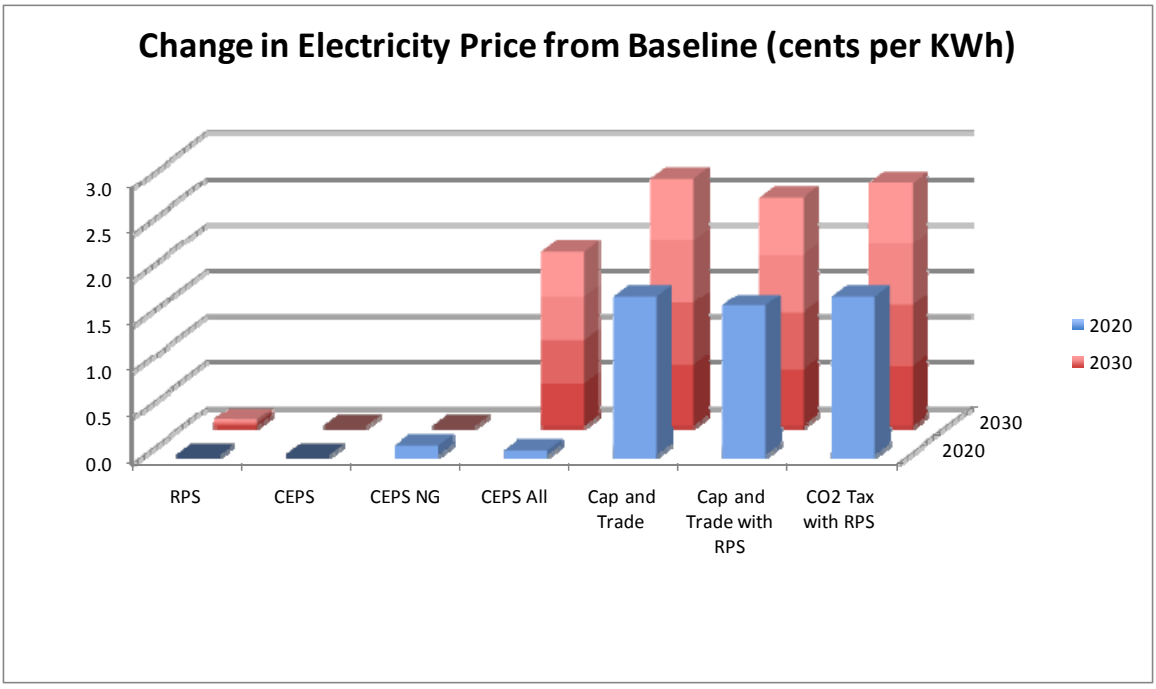
The differences in effectiveness and cost-effectiveness among the different policy scenarios follow from the nature of the incentives each policy creates to reduce demand and switch to the lowest-cost low-carbon sources of electricity. The next several sections discuss the detailed results of the different policy scenarios in terms of electricity prices and demand, generating capacity, generation mix, CO_2 emissions, and effects on oil imports and consumption. These detailed results provide further insights into the effects of different policies on electricity consumers and producers as well as the reasons some policies may be more or less cost-effective than others.

Electricity Price and Demand for Electricity from the Power Sector

One of the most visible indicators of the cost of an electricity-sector policy to consumers is that policy's effect on the price of electricity. The change in electricity price in 2020 and 2030 resulting from each of the policies is shown in Figure 12. Interestingly, the RPS and most forms

of the CEPS have virtually no effect on electricity price in most simulation years either in the absence or presence of cap-and-trade.[30] While these policies raise costs to producers and thus will raise price when price is equal to average cost, they do not consistently raise the marginal cost of generation and could even lower it in some cases. As a result, in those regions of the country where electricity generation is priced in a market, price may go down or up. However, CEPS-All has a positive impact on electricity prices after 2025. By 2030, the electricity price under CEPS-All is 1.9 cents (19 percent) higher than the baseline scenario, while in earlier years the price effect under this scenario is much smaller.

Figure 12. Change in Electricity Price from Baseline



Notes: KWh=kilowatt hours; RPS=renewable portfolio standard; CEPS=clean energy portfolio standard; NG=natural gas; CO2=carbon dioxide.

[30] Three of the policies, RPS, CEPS, and CEPS-NG result in a roughly 3 percent increase in electricity price in 2025, but this price difference disappears by 2030.

Cap-and-trade, on the other hand, always has a positive effect on electricity prices.[31] The cap-and-trade program itself does result in electricity prices that are roughly 1.7 cents (19 percent) higher in 2020 and 2.7 cents (27 percent) higher in 2030 than in the baseline scenario. This price increase creates incentives for consumers to reduce their electricity demand, which helps to lower emissions.

The real price story is these policies' effect on the delivered price of natural gas. Natural gas prices are roughly 3–4 percent lower in 2030 with the RPS, CEPS, and CEPS-NG policies because under these policies, renewables tend to back out natural gas as a source of electricity. This substitution results in lower demand for natural gas from the electricity sector and a lower price of natural gas for all. Note that the effect of the CEPS-NG policy on the delivered price of natural gas is smaller with reductions on the order of 1 percent. The CEPS-All policy has the opposite effect, causing the delivered price of natural gas to be 21 percent higher in 2030 than under the baseline case. This large positive effect on the price of natural gas results from the large increase in demand for natural gas for electricity generation.

Most of the technology-focused policies do not result in a big change in demand for electricity from the utility sector. This appears to be true because demand for electricity is fairly inelastic and the lower natural gas prices under some scenarios provide an added incentive for more end-users to generate their own electricity. However, in 2030, CEPS-All achieves 58 percent of central cap-and-trade reductions in electricity sales. In 2030, under CEPS-All, electricity sales are 206 BkWh (4.5 percent) less than sales in the baseline due to higher electricity prices in 2030 under CEPS-All than other technology-focused policies. Higher electricity prices in CEPS-All are mostly driven by replacing natural gas and renewables for coal generation and reaching the limits imposed by the model on new nuclear capacity installations.

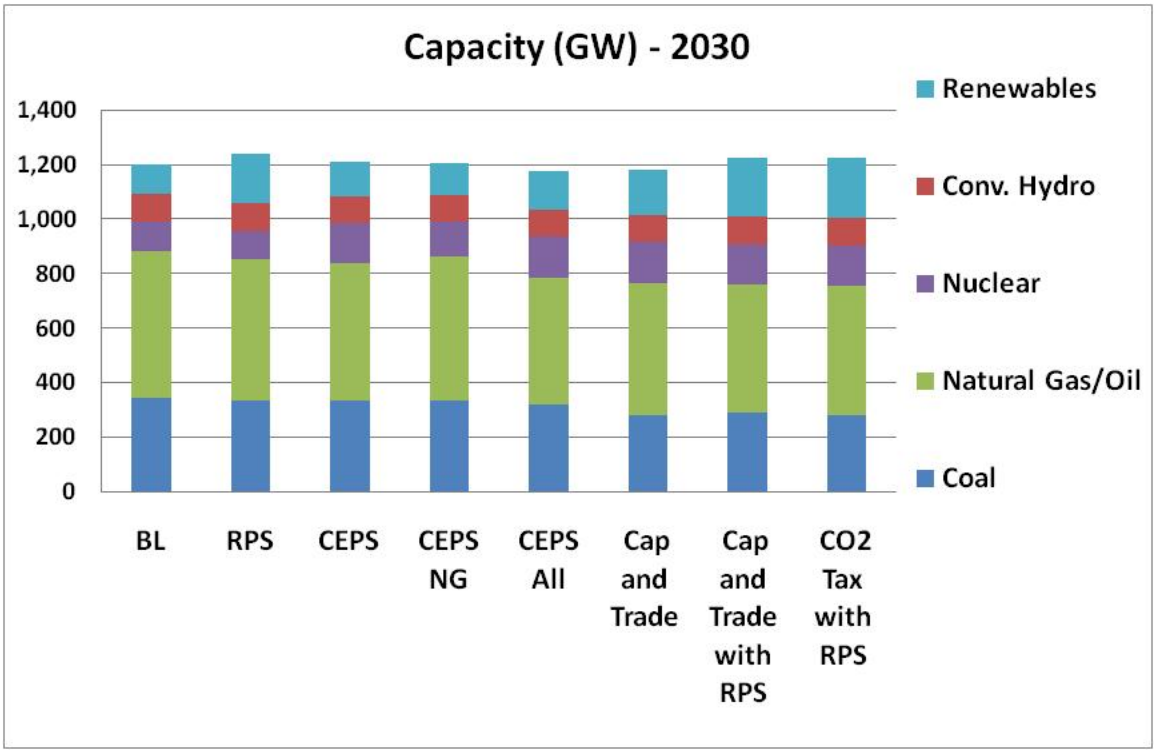
Generating Capacity

The effect of the policies analyzed here on total electricity generation capacity, both within the electricity sector and installed at customer sites, varies across the policies, as shown in Figure 13. The RPS, CEPS, and CEPS-NG policies all lead to a slight increase in total capacity, while the CEPS-All and central cap-and-trade policies yield slightly lower total generation

[31] This effect is due in part to the assumption in this paper that CO_2 emissions allowances are distributed by means of an allowance auction instead of by some mechanism such as allocation to local distribution companies that could mute the price impacts of a cap-and-trade program (Paul et al. 2008)

capacity in 2030 than the baseline. The RPS, CEPS, and CEPS-All policies all result in higher levels of renewables in 2020 than the baseline, and all policies result in higher levels of total renewable capacity in 2030 than the baseline, although the difference is very small for the CEPS-NG policy. The CEPS, CEPS-NG, and CEPS-All policies result in higher levels of nuclear capacity in both 2020 and 2030 than the baseline, with the CEPS and CEPS-All being more effective in this regard. None of the policies has an effect on investment in CCS. For the RPS and straight CEPS policies (without cap-and-trade), renewables capacity grows largely at the expense of natural gas, while for those policies that include CO_2 cap-and-trade, renewables displace coal and natural gas capacity.

Figure 13. Total Generation Capacity by Fuel in 2030

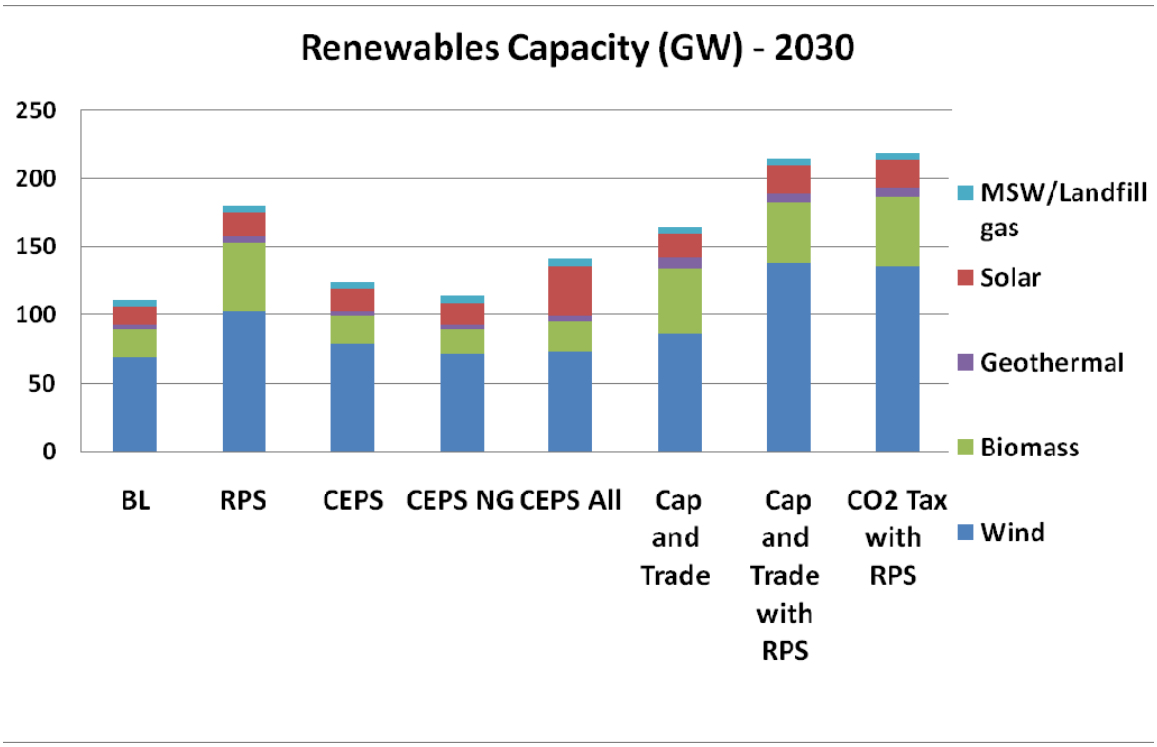


Notes: GW=gigawatts; BL=baseline; RPS=renewable portfolio standard; CEPS=clean energy portfolio standard; NG=natural gas; CO2=carbon dioxide.

By 2030, under an RPS policy, the total capacity of non-hydro renewables is 62 percent higher than in the baseline scenario. The RPS coupled with the cap-and-trade policy leads to levels of renewable capacity that are almost twice as high as levels under the baseline scenario. Most of this additional capacity is wind power, as shown in Figure 14. Biomass capacity is

roughly four times as high in the scenarios that include CO_2 cap-and-trade as it is in the baseline scenario.

Figure 14. Total Non-Hydro Renewable Generation Capacity by Type in 2030



Notes: GW=gigawatts; MSW=municipal solid waste; BL=baseline; RPS=renewable portfolio standard; CEPS=clean energy portfolio standard; NG=natural gas; CO2=carbon dioxide.

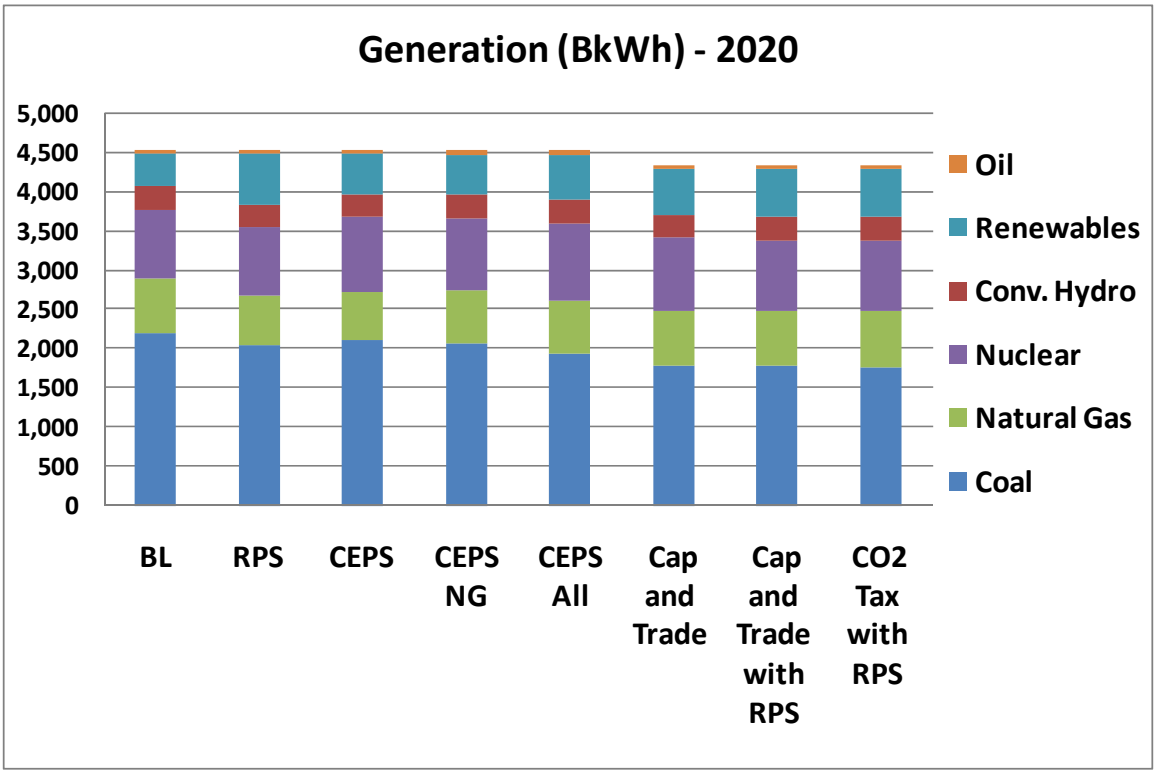
The CEPS and CEPS-All policies have a smaller impact on renewables investment than the RPS and produce an increase in nuclear capacity instead. In 2030, nuclear capacity is 33 percent higher with the CEPS and 36 percent higher with the CEPS-All than in the baseline. Due to its higher capacity factor, less capacity is needed for nuclear than for renewables to provide the same amount of generation. All the scenarios that include a cap-and-trade policy also result in increases in nuclear capacity by 2030 that are comparable to those with the CEPS.

The CEPS-NG policy has the smallest impact on renewables capacity, increasing it by less than 3 percent in 2030. This policy increases the amount of nuclear capacity by 15 percent relative to baseline levels. The CEPS-NG and CEPS-All policies yield 2 percent and 14 percent lower amounts of natural gas capacity, respectively, than the baseline scenario in 2030.

Generation Mix for the Power Sector

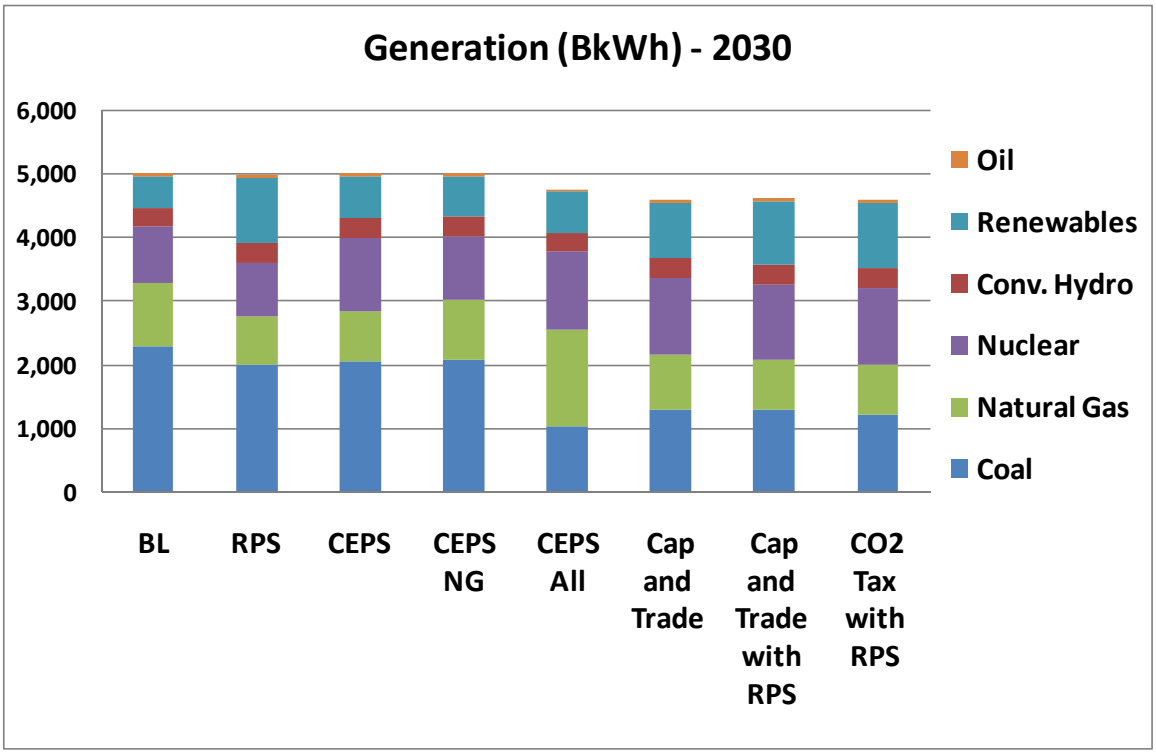
One of the most notable features about the total generation mix for electricity displayed in Figures 15 and 16 is the very small role played by oil-fired generation, which amounts to less than 1 percent of total generation across all the scenarios in 2020 and 2030. The RPS and most CEPS policies by themselves have virtually no impact on oil-fired generation, but in the policy scenarios that include a CO_2 cap-and-trade program, oil-fired generation in 2030 is 12 percent below baseline levels. CEPS-All results in a 6 percent reduction in oil-fired generation in 2030 compared to baseline.

Figure 15. Total Electricity Generation by Fuel in 2020



Notes: BkWh=billion kilowatt hours; BL=baseline; RPS=renewable portfolio standard; CEPS=clean energy portfolio standard; NG=natural gas; CO2=carbon dioxide.

Figure 16. Total Electricity Generation by Fuel in 2030



Notes: BkWh=billion kilowatt hours; BL=baseline; RPS=renewable portfolio standard; CEPS=clean energy portfolio standard; NG=natural gas; CO2=carbon dioxide.

The policies vary substantially in their effect on other types of fossil generation. The RPS scenario leads to coal generation in 2030 that is 13 percent below baseline levels, while the CEPS policy results in a 10 percent decrease in coal generation. The effects on natural gas generation are much larger, with gas generation roughly 23 percent below baseline levels under the RPS policy and 22 percent lower under the CEPS policy. Under these scenarios, the share of natural gas in total electricity generation changes from baseline levels of 19 percent to 15 percent under the RPS and CEPS policies, as shown in Figure 16.

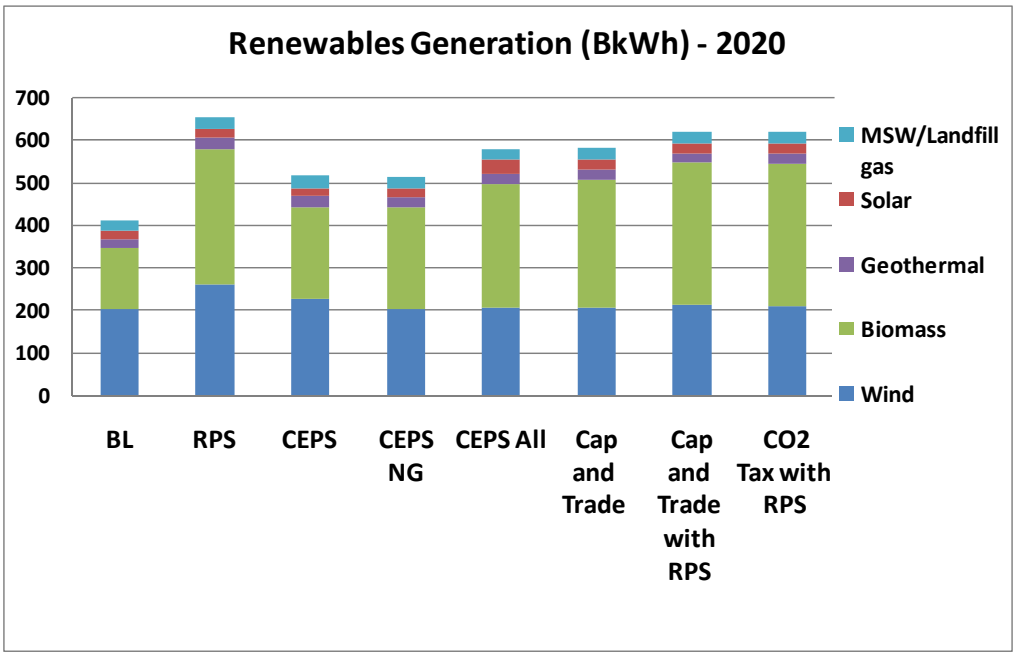
Under the CEPS-NG policy, adding incremental natural gas generation to the CEPS policy results in more natural gas generation and less generation from renewables and nuclear than the CEPS policy. The CEPS-NG policy has the smallest impact on coal-fired generation of all the portfolio policies, primarily because much of the generation in the 25 percent portfolio standard occurs anyway in the baseline.

Encouraging greater use in the CEPS-All scenario of the technologies that do not burn coal or that sequester carbon, in proportion to their carbon intensity, results in dramatically less

coal generation and more natural gas generation than the baseline and other RPS and CEPS policies. In 2030, CEPS-All results in a greater reduction in conventional coal generation (1,260 BkWh, 55 percent) than even central cap-and-trade (1,150 BkWh, 50 percent). Natural gas generation under the CEPS-All scenario increases dramatically compared to the baseline, unlike all other policy scenarios, which result in less natural gas generation than baseline by 2030. In 2030, natural gas generation under CEPS-All accounts for 32 percent of total generation due to a 546 BkWh (56 percent) increase in natural gas generation from the baseline.

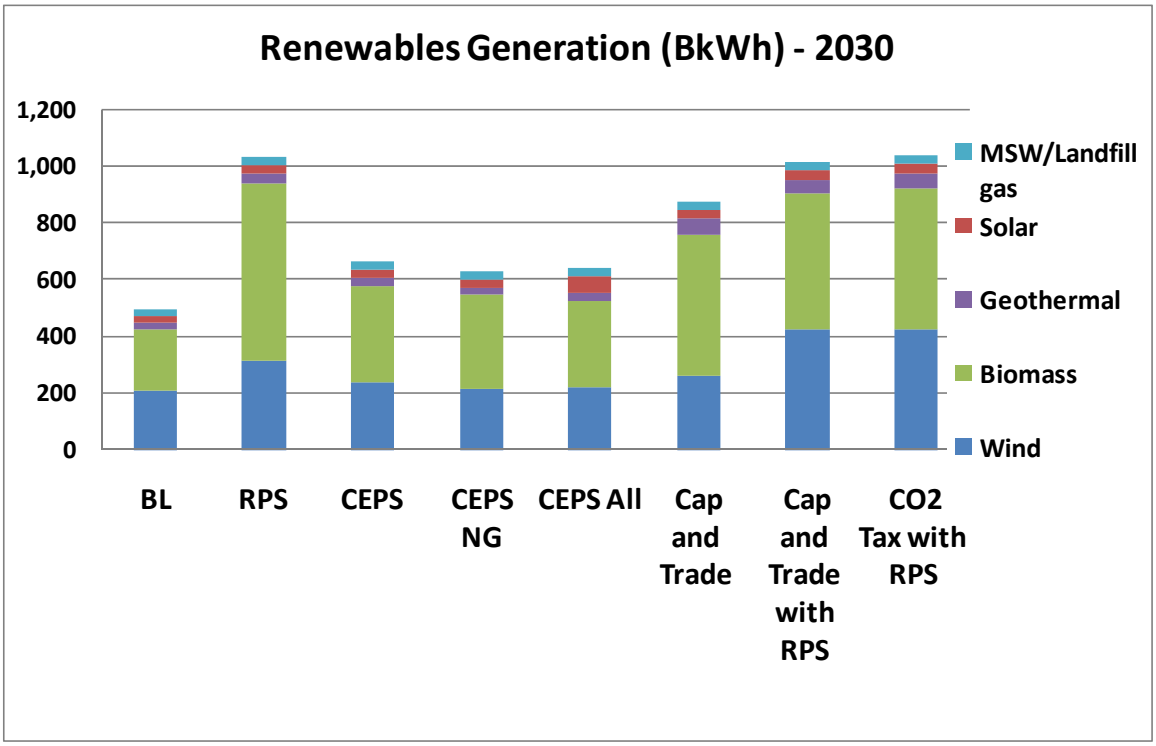
The policies also differ in terms of their effects on generation by non-hydro renewables, as shown in Figures 17 and 18. The RPS policy scenario produces the biggest effect on generation by non-hydro renewables, with total generation of slightly more than 1,000 billion kWh in 2030, more than twice the 2030 level in the baseline scenario. The levels of renewable generation under the two RPS scenarios that include a carbon policy are roughly comparable, as shown in Figure 18. The CEPS scenario results in total generation by non-hydro renewables that is 34 percent above baseline levels in 2030. Most of this additional generation comes from biomass with only slightly higher levels of wind generation. The CEPS scenario has a comparable effect on nuclear generation in 2030 yielding 32 percent higher generation than in the baseline scenario.

Figure 17. Total Electricity Generation from Non-Hydro Renewables by Type in 2020



Notes: BkWh=billion kilowatt hours; MSW=municipal solid waste; BL=baseline; RPS=renewable portfolio standard; CEPS=clean energy portfolio standard; NG=natural gas; CO2=carbon dioxide.

Figure 18. Total Electricity Generation from Non-Hydro Renewables by Type in 2030



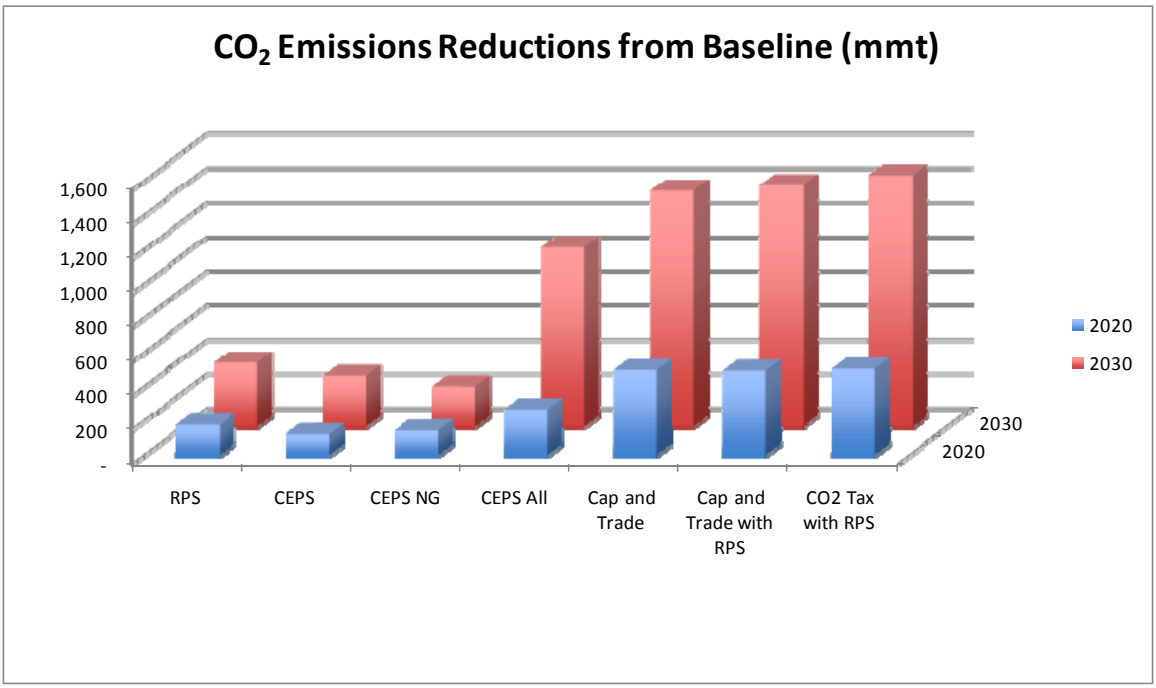
Notes: BkWh=billion kilowatt hours; MSW=municipal solid waste; BL=baseline; RPS=renewable portfolio standard; CEPS=clean energy portfolio standard; NG=natural gas; CO2=carbon dioxide.

The CEPS-NG policy yields 26 percent greater generation from renewables and 14 percent more nuclear generation in 2030 than the baseline. The CEPS-All scenario achieves non-hydro renewables–generation levels comparable to central cap-and-trade in 2020, but by 2030 renewables generation is only slightly above CEPS-NG levels. The CEPS-All policy achieves a slightly different non-hydro renewables–generation mix than the other CEPS policies: CEPS-All in 2030 has twice as much solar generation but 9 percent less biomass generation as CEPS-NG. The scenarios that couple a CO_2 policy with a floor on renewables generation result in roughly 50 percent increases in renewables generation by 2020 and 100 percent increases in wind and geothermal generation relative to the baseline for 2030, as shown in Figures 17 and 18. Geothermal generation in 2030 attains its highest level under the central cap-and-trade scenario, coming in at roughly 240 percent of the level in the baseline scenario.

CO_2 Emissions Reductions

By themselves, most policies to promote renewables produce only modest reductions in U.S. energy-related CO_2 emissions, as shown in Figure 19 and Table 7. In 2030, the RPS and CEPS policies reduce emissions by 377 and 299 mmt, respectively. The CEPS-NG policy yields emissions reductions in 2020 that are halfway between those resulting from the CEPS and RPS policies in 2020, but by 2030, it results in fewer reductions than either of the other portfolio policies. In all these portfolio policy cases, the reductions in total greenhouse gas emissions are all coming in the form of CO_2 emissions reductions. In 2020, the RPS policy reduces CO_2 emissions by 40 percent more than the CEPS policy, but by 2030 the gap narrows to 25 percent.

Figure 19. Reductions in Total CO_2 from Energy Use under Each Policy



Notes: mmt=million metric tons; RPS=renewable portfolio standard; CEPS=clean energy portfolio standard; NG=natural gas; CO2=carbon dioxide

Table 7. Greenhouse Gas Emissions (million metric tons)

	Energy CO_2	Reduction from baseline	Total greenhouse gases	Reduction from baseline
	2020			
Baseline	5883		7383	
RPS	5704	179	7207	176
CEPS	5758	125	7261	122
CEPS-NG	5735	148	7237	146
CEPS-All	5612	271	7114	269
Cap-and-trade	5384	499	6658	725
Cap-and-trade with RPS	5388	495	6665	718
CO_2 tax with RPS	5376	507	6650	733
	2030			
Baseline	6186		7946	
RPS	5816	370	7570	376
CEPS	5894	292	7647	299
CEPS-NG	5956	230	7709	237
CEPS-All	5145	1041	6896	1050
Cap and Trade	4815	1371	6290	1656
Cap and Trade with RPS	4784	1402	6263	1683
CO_2 tax with RPS	4724	1462	6199	1747

Notes: CO_2=carbon dioxide; RPS=renewable portfolio standard; CEPS=clean energy portfolio standard; NG=natural gas.

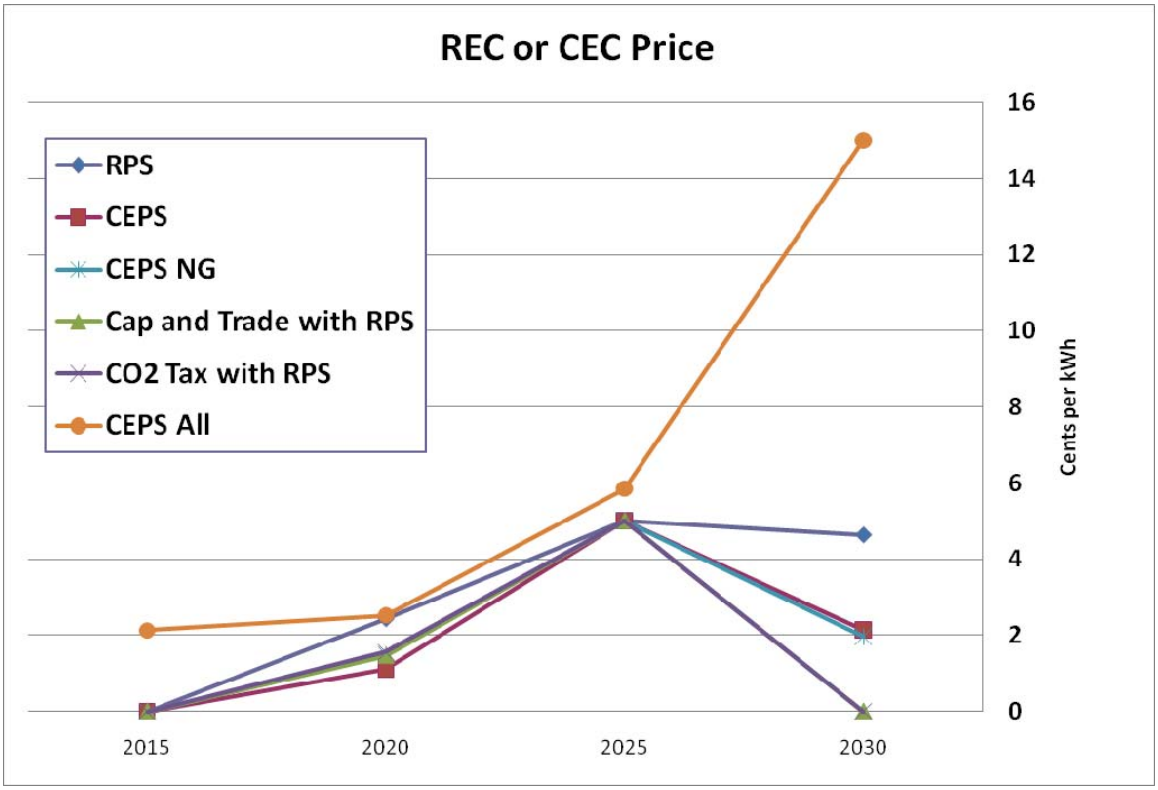
The one exception to this finding is the CEPS-All policy, which is the most effective of the technology policies at reducing CO_2 emissions. The CEPS-All policy results in 62 percent of central cap-and-trade CO_2 emissions reductions over the entire study period, 2010–2030. Domestic energy-related CO_2 emissions under CEPS-All are 269 mmt (5 percent) lower in 2020 and 1,048 mmt (17 percent) lower in 2030 than in the baseline.

The cap-and-trade policy has a much bigger impact on emissions of energy-related CO_2 and other greenhouse gases than the renewables policies by themselves. The central cap-and-trade policy yields a nearly 500 mmt (8 percent) reduction in CO_2 emissions in 2020 and more than a 1,350 mmt (22 percent) reduction in CO_2 emissions in 2030 compared to baseline. Coupling a CO_2 tax (where the tax level equals the CO_2 allowance price under the central cap-and-trade program) with the RPS requirement of 25 percent renewables leads to 100 mmt fewer CO_2 emissions in 2030 than the central cap-and-trade policy, about an 8 percent improvement in CO_2 emissions reductions.

Renewable Energy Credit, Clean Energy Credit and CO_2 Allowance Prices

Several policies analyzed here create new intangible assets that are tradable. The market prices of these assets, which include renewable energy credits created by all policies that have a renewable portfolio standard, clean energy credits created by the CEPS , CEPS-NG, and CEPS-All policies, and CO_2 emissions allowances created by the cap-and-trade policy, vary over time and across policies. The prices of these assets are outputs of the NEMS-RFF model simulations. If, in a particular simulation year, the amount of generation of a particular type required by the policy is below what would happen in the absence of that requirement, then the policy is not binding and the price for the created asset is zero. The RPS, CEPS, and CEPS-NG policies do not bind in 2015 and thus yield a zero price on the relevant credits in that year, as shown in Figure 20. The CEPS-All scenario always binds, and thus the credit price never falls to zero for this scenario.

Figure 20. Price of RECs or CECs (depending on scenario in 2007 Cents per kWh)



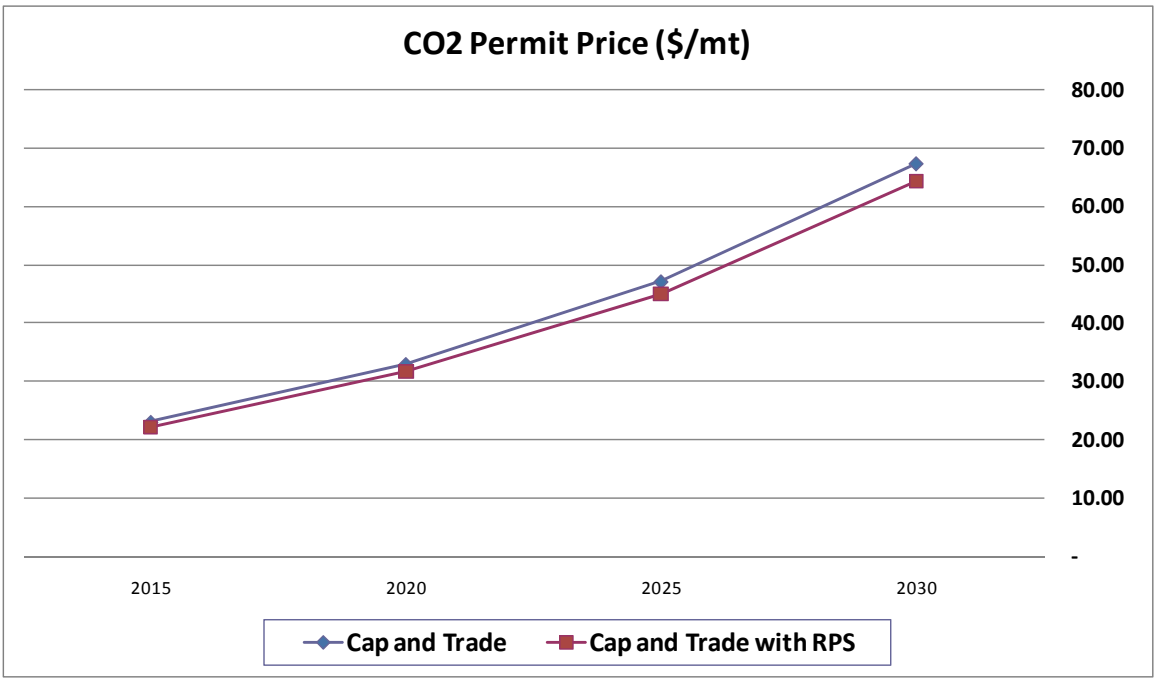
Notes: RECs=renewable energy credits; CECs=clean energy credits; kWh=kilowatt hours; RPS=renewable portfolio standard; CEPS=clean energy portfolio standard; NG=natural gas; CO2=carbon dioxide

Another feature of both the RPS and CEPS policies, with the exception of the CEPS-All policy, is the cap of 5 cents per kWh on the price of the particular type of credits created by the policy. Once the market price of credits hits that cap, those responsible for compliance with the portfolio standard can simply pay a fee equal to the capped price times their renewable or clean energy requirement and avoid having to purchase credits. Both the REC and CEC prices (under both CEPS and CEPS-NG) hit the price cap of 5 cents per kWh in 2025 and then fall in 2030, as shown in Figure 20. The CEPS-All case does not feature a CEC price cap, and by 2025, the CEC price surpasses 5 cents per kWh. In 2030, the CEC price is 15 cents per kWh.

With the exception of 2025, the CEC price under the CEPS policy is lower than the REC price. The CEC price with the CEPS-NG policy is equal to the REC price in 2020 but aligns with the CEC price for the CEPS policy in 2030. REC prices are lower when the RPS is combined with a CO_2 policy than otherwise. The RPS policy is not binding in 2030 when a CO_2 policy is in place, and thus REC prices fall to zero in that year under those policy scenarios. The CEC price under the CEPS-All scenario exceeds the REC price in virtually every year. Under the CEPS-All, the CEC price always binds because the policy seeks to achieve a contribution from clean generators that is substantially larger than what occurs in the baseline, particularly in the later simulation years. For this scenario, the CEC price increases from 2 cents per kWh in 2015 to 15 cents per kWh in 2030.

The time path of CO_2 allowance prices for the two cap-and-trade scenarios modeled is displayed in Figure 21. As expected, prices rise over time at roughly the rate of interest due to the possibility of allowance banking. The combination of an RPS with the climate cap-and-trade policy results in a slightly lower time path for CO_2 allowance prices.

Figure 21. CO_2 Allowance Price with and without RPS



Notes: mt=metric ton; RPS=renewable portfolio standard

Imports of Petroleum Products and Liquid Fuels

As noted earlier, because oil-fired generation plays such a small role in total electricity supply, our ex ante expectation was that policies to promote renewables in electricity generation would have a very small effect on U.S. oil imports. The results are consistent with this expectation: the policies to promote renewables have no effect on imports of crude and petroleum products.

The story is somewhat different with respect to the effect of the policies on petroleum supply, although the effects, when they exist, are very small. The RPS and CEPS result in respective reductions of 200,000 barrels per day (1 percent) and 100,000 barrels per day (0.5 percent) in 2030 of total petroleum supply. This is potentially due in part to the lower natural gas prices under these scenarios, which reduce natural gas supply and could also reduce oil production when there is a joint product. The CEPS-NG and CEPS-All policies result in no total petroleum supply reductions in 2030.

All the policies that include a CO_2 policy result in at least one million barrels per day (nearly 6 percent) lower total petroleum supply compared to the baseline in 2030 and 700–800 thousand (10 percent) fewer barrels per day of crude and petroleum imports compared to the

baseline in 2030. These effects are due to the climate policy and are not affected materially by the addition of an RPS policy, as shown in Table 8.

Table 8. Petroleum Products in 2030 (million barrels per day)

	Imports of crude and petroleum products	Reduction from baseline	Total petroleum	Reduction from baseline
	2030			
Baseline	8.2	----	18.0	---
RPS	8.2	0	17.8	0.2
CEPS	8.2	0	17.9	0.1
CEPS-NG	8.2	0	18.0	0.0
CEPS-All	8.0	0.2	18.0	-0.1
Cap-and-trade	7.4	0.8	16.9	1.0
Cap-and-trade with RPS	7.5	0.7	16.9	1.1
CO_2 tax with RPS	7.5	0.7	16.9	1.1

Notes: RPS=renewable portfolio standard; CEPS=clean energy portfolio standard; NG=natural gas; CO_2=carbon dioxide.

5.4 Renewable and Incremental Natural Gas Portfolio Standards (RINGPS)

Concern about limits to our ability to expand renewable-generating capacity and siting as well as other regulatory and cost barriers to quick expansion of nuclear-generating capacity in the United States has led some to advocate for more active promotion of gas-fired electricity generation. As a part of the climate bill S. 1733, introduced by Senators John Kerry (D-MA) and Barbara Boxer (D-CA) and otherwise known as the Clean Energy Jobs and American Power Act, Subtitle H provides for an incentive payment to promote use of up to 300,000 GWh of dispatchable power generation that achieves lower CO_2 emission rates than electricity sector-wide average levels in 2007, and natural gas generators would be a natural candidate for this subsidy. Given this newfound enthusiasm for natural gas's role in the electricity generation mix (see Brown et al. 2009), we model an additional policy that provides a separate incentive for the use of this relatively low-carbon fossil fuel alongside no-carbon renewable sources. The policy, which is titled the Renewable and Incremental Natural Gas Portfolio Standard (RINGPS), combines a 25 percent RPS with a 20 percent incremental natural gas portfolio standard,

meaning that 25 percent of total electricity generation (excluding generation from hydro and municipal solid waste plants) must come from renewables and 20 percent must come from new natural gas plants. This policy does not include a cap on the price of the renewable and incremental natural gas generation credits that are created by the policy, a feature that tends to increase the welfare cost of the policy.

The RINGPS is more stringent than the other portfolio standard policies considered in this analysis, with the exception of the CEPS-All policy, and thus it is not surprising that it produces a larger drop in CO_2 emissions than most of the other portfolio standards considered here. This policy reduces emissions of energy-related CO_2 (almost all of which come from the electricity sector) by 6.6 billion tons over the 20-year time horizon, which is roughly twice as much as the RPS policy that we model and roughly half as much as the central cap-and-trade scenario. However, while this policy is more effective than the RPS, CEPS, and CEPS-NG policies, it is also substantially more costly. The net present value of total welfare cost over the policy period (2010–2030) for the RINGPS policy is more than $160 billion, compared to just over $140 billion for central cap-and-trade and $48 billion for the RPS. Combining the cost and emissions reductions shows that the cost per ton of CO_2 emissions reduction is roughly $24 per ton for the RINGPS, substantially higher than the main policies discussed in section 5.2.

The analysis of the RINGPS policy demonstrates the importance of energy efficiency and conservation and nuclear power in containing costs. The RINGPS policy has a high welfare cost because relatively expensive technologies (natural gas and renewables) are mandated to comprise nearly half of the energy mix for electricity. The RINGPS policy decreases nuclear generation by 15 percent relative to baseline and does not take advantage of low-cost CO_2 emissions reductions associated with lower electricity consumption because electricity production in 2030 is virtually the same as it is under the baseline. Coal generation is reduced relative to the baseline, but not as much as in central cap-and-trade scenario.

6. Qualitative and Unmodeled Aspects of Policies

The model results discussed above provide important and useful insights regarding the effects of different policies on electricity supply and emissions. However, the model fails to capture a number of issues, including political issues, unmodeled constraints and the role of non-environmental market failures. A number of uncertainties regarding fuel prices and other factors not considered in the modeling also could have implications for the results. Several are discussed in this section.

6.1 Political Issue Related to Modeled Policy Scenarios

On the political side, the U.S. Senate has tried several times in the past few sessions to pass an RPS standard that is as strict as the one modeled here (25 percent renewables by 2025) but has failed to do so. Even in the 110th session of Congress, the final RPS embodied in the American Clean Energy Leadership Act reported out of the Senate Energy and Natural Resources Committee on July 16, 2009, had a 15 percent floor in 2021 with the possibility of up to 4 percent of those credits granted for savings from energy-efficiency programs. This program is similar in stringency to the one included in the Waxman–Markey climate bill. Members of Congress, including former Senator Norm Coleman (R-MN) and Senator Lugar, have made proposals to expand the set of generators that are covered by the RPS standard, but these proposals have not advanced very far in the Congress either. These experiences highlight the political challenges of realizing the goals embodied in the RPS and CEPS policies modeled here, although we are probably closer now than we ever have been to having a federal RPS.

6.2 Transmission Constraints and Siting Difficulties

One of the important barriers to rapid increases in the amount of renewable generation supplied to the U.S. electricity market is the lack of adequate transmission capacity to transmit that power from where the resources are located to where it would be consumed. A prime example is the distance between the areas in the windy plain states and the large electricity markets to the east and west. The costs of transmission necessary to bring remotely located wind power, for example, to the nearest connection point on the grid are represented in the NEMS-RFF model, but the further costs of getting that power to market may be under-represented due to the fact that transmission is essentially unconstrained within each NEMS-RFF electricity market model region. The model also likely does not represent the amount of time it takes to add new transmission lines, which can be many years longer than the time needed to construct a wind farm. The further costs (in terms of dollars and delay) imposed by processes necessary to get siting approval are also not represented in the model, and thus the results presented here may be overly optimistic in terms of the amount of wind capacity that could be brought online to meet policy goals, particularly in the near term. If siting is more difficult in areas with lower cost resources, this will raise the cost of the RPS policy relative to our modeled results.

6.3 Land Use and Renewables Siting

A recent study by the Nature Conservancy suggests that as the U.S. moves toward greater reliance on renewable energy sources in an effort to combat climate change, the land use

intensity of our electricity supply will increase dramatically, particularly if we increase our reliance on biomass sources of energy or limit development of new nuclear capacity or CCS capability (McDonald et al. n.d.). The authors explore the impact of this supply on different types of land and suggest that greater reliance on energy efficiency is a way to avoid adverse impacts on land use.

6.4 Constraints on Adding New Nuclear Capacity

The NEMS-RFF model does not include any strict limits on how much nuclear capacity can be added. The model does limit the speed with which new capacity of any type can be added by imposing a capital cost penalty when the model attempts to add a large amount of capacity of a particular type in a given year. For purposes of this project, we have imposed a ceiling that limits the total amount of new nuclear capacity that can be added by 2030 to an additional 50 GW. However, the regulatory hurdles that must be met, including overcoming local opposition to construction of new facilities, before this can happen remain large, and it is uncertain how much U.S. nuclear capacity can be added in the next 30 years.

6.5 Fuel Cost Uncertainty

A major factor in determining the cost of all the modeled policies is the price of natural gas. If new technologies result in a substantially lower price of natural gas than that modeled here, it will raise the opportunity cost of meeting the renewable and clean energy standards and thus raise the cost of using the standards-based approach to reduce greenhouse gases. In addition, lower natural gas prices will tend to lower CO_2 allowance prices at least in the near term, thus widening the gap between the cost-effectiveness of a cap-and-trade approach and a renewables policy.

6.6 Other Market Failures

One of the rationales given for RPS policies or renewable tax credits is that because renewables are nascent (or developing) technologies, individual investors in renewables may be unable to internalize substantial benefits from learning by doing. As a result, the market underinvests in renewables from a social perspective. The size of the learning-by-doing externality and it variance across different technologies are not well understood, although estimates from the literature suggest that for both wind and solar, they may be quite small (Fisher and Newell 2008; Nemet 2006). In this analysis, we do not take any benefit associated with addressing this externality into account when we evaluate the costs of the renewables policies.

As a result, we may tend to overstate the costs of the policy, which will bias upward our cost-effectiveness measures.

Electricity markets are also subject to varying degrees of price regulation that create a wedge between the electricity price and the marginal cost of supply. Roughly half the electricity consumers in this country reside in states that have introduced market pricing of electricity generation and some degree of customer choice of electricity provider. In those regions, assuming electricity generation markets are competitive, the price for the generation component of electricity (roughly 60 percent of the total retail price) is set at marginal cost. In the rest of the country, electricity generation is priced at average cost. Everywhere, the transmission and distribution portion of the electricity supply remains a natural monopoly, and the price for the delivery component of electricity service is set at average cost in most places.[32] Thus regulation creates a gap between price and marginal cost that will result in inefficiencies. When regulated prices lie below marginal cost, the introduction of a carbon policy can help to close that gap because carbon policies such as cap-and-trade tend to increase average cost by more than they increase marginal cost (Burtraw et al. 2001).

7. Conclusion

The results of this analysis clearly indicate that offering tax credits for renewables or imposing a floor on generation from renewables or other clean generating technologies is not as effective or cost-effective in reducing CO_2 emissions as an economy-wide cap-and-trade or carbon tax policy. Increased reliance on renewables and other zero- and low-emitting generation technologies will be an important part of the solution for reducing CO_2 emissions from electricity production, and the tax credits and generation floor policies analyzed here succeed to varying degrees in meeting that objective. However, these policies do not provide sufficient incentives for switching away from coal-fired generation or for reducing electricity consumption. Indeed, by lowering electricity price in some years, the tax credit policy tends to promote more electricity consumption, a definite move in the wrong direction. All the pro-renewable and clean technology policies modeled here have essentially no effect on oil imports and petroleum use in

[32] Exceptions may occur when electricity prices are set using price cap regulation, thus divorcing, at least for some amount of time, the strict link between prices and costs. Even regions with average cost pricing will have time delays in the updating of rates, and such regulatory delay can provide incentives similar to those under price caps.

the United States, and the cap-and-trade policy leads to only slight reductions in total petroleum use, on the order of 2 percent.

The policies that impose floors on renewable or clean generation are generally less cost-effective than the cap-and-trade approach for several reasons:

- They are limited to the electricity sector and thus may encourage socially inefficient fuel switching away from electricity to other sources of energy.
- In most cases, they do not discriminate among the more and less carbon-intensive fossil technologies that renewables or other non- or low-emitting technologies are likely to displace. As a result, they have a limited effect on the use of coal-fired generation.
- In some cases, they single out a particular group of zero- or low-carbon technologies that may not be the least-cost package of options for reducing emissions.
- They generally do not have a large effect on electricity price and thus provide inadequate incentives for electricity conservation.
- They give "credits" toward meeting the generation floor to renewable and new clean generation that occurs in the baseline and thus does not contribute to emissions reductions. This is especially true for the more flexible standards.

Making the generation floor policy more flexible by expanding the set of eligible technologies while holding the level of the floor constant tends to lower the effect of the policy on CO_2 emissions without increasing average cost. On the other hand, increasing the share of generation that must come from renewables or clean energy tends to increase the CO_2 emissions reductions and the average cost of the policy.

The inclusion of a renewable portfolio standard in H.R. 2454 suggests that this type of policy may be part of a federal cap-and-trade law. Combining these two policies will have no effect on overall CO_2 emissions; however, if the RPS floor is binding, it will lower the price of CO_2 allowances and raise the overall cost of the policy. Also, if the cap-and-trade policy includes a safety valve or ceiling on the price of allowances, then adding an RPS policy to the mix could reduce the likelihood that that price cap will be triggered. Combining a cap-and-trade policy with an RPS could be justified on the grounds of market failures related to R&D or adoption of new technologies and learning by doing, but the magnitude of these externalities is not well understood and is a subject of some controversy in the literature.

An alternative way to control CO_2 and add some predictability regarding the cost of the policy is to use a carbon tax. When CO_2 is subject to a tax instead of a cap, policies that increase

use of renewables could result in incremental emissions reductions. In this analysis, we consider a carbon tax that yields the same prices as the cap-and-trade program represented in central cap-and-trade scenario. Adding an RPS to the CO_2 tax policy yields small incremental reductions in CO_2.

Important areas for new research remain. While the renewable and clean energy policies considered here offer a relatively costly approach to reducing CO_2 emissions, they could be effective in addressing other market failures related to R&D or technological learning. The costs of dealing with intermittency of wind and solar and the challenges associated with siting and building the transmission necessary to bring electricity from the renewable sources to market are also subject to a great deal of uncertainty. Designing efficient policies to address these challenges will require a better understanding of the nature and extent of these potential market failures as well as how effective different policies might be in addressing them.

Appendix 1. Methods for Calculating Welfare Costs and Cost-Effectiveness of Policies

We measure the cost of the policies by calculating the deadweight economic losses to consumers and producers created by these policies. In addition to direct costs, we also consider the change in the cost associated with preexisting distortions created by existing tax credits or, in the cases that combine a cap-and-trade policy with an RPS, changes in the distortion resulting from the cap-and-trade policy. In every case, we calculate annual values of deadweight loss for all years from 2010 to 2030 as well as the present discounted value of the stream of costs, discounting back to 2010 using a 5 percent discount rate. The particular approach used to calculate the annual deadweight losses for each of four categories of policies is discussed below. In the paper we focus on the present discounted value of the costs.

Extended Renewable Tax Credits: Renewable tax credit policies, including the production tax credit for wind, solar, biomass and landfill gas and the investment tax credit for solar are built into the baseline and central cap-and-trade scenarios, as well as the RPS and CEPS scenarios. However, these existing policies expire early in the next decade. Under the extended tax credit policy scenario, these tax credits are extended indefinitely as described above in the section on policy scenarios.

These tax credits serve as a subsidy to the supply of generation from eligible renewable technologies. In any given year, the deadweight loss associated with that subsidy is approximately equal to the change from the baseline in generation from the collection of eligible renewable technologies multiplied by the size of the effective subsidy associated with the tax credit.

Clean Energy Floors: The RPS and the three CEPS policies (as well as the RINGPS) impose a floor on generation from clean technologies in the form of a minimum percentage of total electricity sold that must come from eligible generators. We assume that the responsibility for meeting this standard is imposed on the entity that delivers electricity to consumers and that the policy is equivalent to a subsidy to renewables or clean generation (equal to the REC or CEC credit price) combined with a tax on electricity sales (equal to the REC credit price times the minimum renewable share). The welfare costs of these types of policies consist of three components, which are added together:

- the distortion created by the subsidy paid to renewables and, depending on the policy, other clean generators calculated as 0.5x(the sum over eligible technologies of the credit

price)x(the number of credits per kWh generated for each eligible technology times the change in generation for each eligible technology);

- the distortion created by the implicit tax imposed on electricity sales equal to 0.5x(the change in total electricity sales resulting from the policy)x(the change in the price of electricity resulting from the policy); and
- the change in the preexisting distortion from the renewables tax credits (including both the production tax credit and the investment tax credit), which equals the difference between the subsidy payments in policy and the subsidy payments in the baseline.

CO_2 Cap-and-Trade (Central Cap-and-Trade): For comparison purposes, we also present the results of the central cap-and-trade CO_2 cap-and-trade scenario and consider its costs. This cost estimate is based on mapping allowance prices and CO_2 emissions reductions from baseline levels in each year and then constructing the implied marginal abatement cost curve. The area under it gives an estimate of total annual costs of the cap-and-trade policy for the level of emissions reductions that we model. We add to this estimate the cost of any changes in the preexisting distortion from the production and investment tax credits to renewables resulting from the cap-and-trade system.

Policy Combinations: Two of the policies that we analyze combine a CO_2 policy, either in the form of a tax or a cap-and-trade system, with a RPS policy. To calculate the costs of these policy combinations, we take the welfare cost of the central cap-and-trade case and add to it the value of the market distortion created by subsidizing clean technologies and the market distortion created by the implicit output tax (both relative to the central cap-and-trade or equivalent tax case), plus the change in the preexisting distortions resulting from the renewable tax credits associated with the combined policy, relative to the baseline case.

References

American Wind Energy Association (AWEA). 2009. *Annual Wind Industry Report, Year Ending 2008*. Washington, DC: AWEA. http://www.awea.org/publications/reports/AWEA-Annual-Wind-Report-2009.pdf (accessed October 12, 2009).

Banzhaf, Spencer, Dallas Burtraw and Karen Palmer. 2004. Efficient Emission Fees in the U.S. Electric Sector. *Resource and Energy Economics* 26(3): 317–41.

Bird, Lori, and E. Lockey. 2007. *Interaction of Compliance and Voluntary Renewables Energy Markets*. NREL/TP-670-42096. Golden, CO: National Renewable Energy Laboratory.

Bird, Lori, Leila Dagler, and Blair Swezey. 2007. *Green Power Marketing in the United States: A Status Report (10th Edition).* Technical Report NREL/TP-670-42502. Golden, CO: National Renewable Energy Laboratory.

Bird, Lori, Claire Kreycik, and Barry Friedman. 2008. *Green Power Marketing in the United States: A Status Report (11th Edition).* Technical Report NREL/TP-6A2-44094. Golden, CO: National Renewable Energy Laboratory.

Borenstein, Severin. 2008a. The Market Value and Cost of Solar Photovoltaic Electricity Production. Working paper 176 (Berkeley, CA: University of California at Berkeley, Center for the Study of Energy Markets).

Borenstein, Severin. 2008b. Response to Critics of 'The Market Value and Cost of Solar Photovoltaic Electricity Production.' http://faculty.haas.berkeley.edu/borenste/SolarResponse.pdf (accessed April 22, 2008).

Brennan, Tim, Karen Palmer, and Salvador Martinez. 2002. *Alternating Currents: Electricity Markets and Public Policy*. Washington DC: RFF Press.

Brown, Stephen, Alan Krupnick, and Margaret Walls. 2009. Natural Gas: A Bridge to a Low-Carbon Future? Issue brief 09-11. Washington, DC: Resources for the Future.

Burtraw, Dallas, Karen Palmer, Ranjit Bharvirkar, and Anthony Paul. 2001. The Effect of Allowance Allocation on the Cost of Carbon Emission Trading. Discussion paper 01-30. Washington, DC: Resources for the Future.

EIA. (U.S. Energy Information Administration). 2006. *Energy Market Impacts of a Clean Energy Portfolio Standards*. SR/OIAF/2006-02. Washington, DC: EIA.

EIA. 2007a. *Energy Market Impacts of a Clean Energy Portfolio Standard—Follow Up*. SR/OIAF/2007-02. Washington, DC: EIA.

EIA. 2007b. Analysis of Alternative Extensions of Existing Production Tax Credit for Wind Generator. http://www.eia.doe.gov/oiaf/servicerpt/ptc/index.html (accessed October 12, 2009).

EIA. 2009a. *Assumptions to the Annual Energy Outlook 2009*. DOE/EIA-0554. Washington, DC: EIA.

EIA. 2009b. *Commercial Sector Demand Module of the National Energy Modeling System: Model Documentation 2009*. DOE/EIA-M066. Washington, DC: EIA.

EIA. 2009c. *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*. DOE/EIA-M067. Washington, DC: EIA.

EIA. 2009d. *Model Documentation Renewable Fuels Module of the National Energy Modeling System*. DOE/EIA-M069. Washington, DC: EIA.

EIA. 2009e. *Energy Market and Economic Impacts of the American Clean Energy and Security Act of 2009*. SR OIAF/2009-05. Washington, DC: EIA.

EIA. 2009f. *Electric Power Monthly*. DOE/EIA-0226. Washington, DC: EIA.

EIA. 2009g. Renewable Energy Consumption and Electricity Preliminary

Statistics 2008. http://www.eia.doe.gov/cneaf/alternate/page/renew_energy_consump/rea_prereport.html (accessed July 2009).

EIA. 2010. *Electric Power Annual 2008*. DOE/EIA-0348 (2008). Washington, DC: EIA.

Fischer, Carolyn, and Richard Newell. 2008. Environmental and Technology Policies for Climate Mitigation. *Journal of Environmental Economics and Management* 55(2): 142–62.

GeothermEx, Inc. 2004. *New Geothermal Site Identification and Qualification. Report to the California Energy Commission*, Public Interest Energy Research Program, Sacramento, Calif.

Green, Bruce and R.Gerald Nix. 2006. *Geothermal: The Energy Under Our Feet*, NREL/TP-840-40665, Golden, Colorado: National Renewable Under Lab.

Interagency Working Group on Social Cost of Carbon (2010) *Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*. Washington, DC: U.S. Environmental Protection Agency.

Jaffe, Adam B., Richard G. Newell, and Robert N. Stavins. 2005. A Tale of Two Market Failures: Technology and Environmental Policy. Ecological Economics 54(2–3): 164–74.

McDonald, Robert I., Joseph Fargione, Joe Kiesecker, William M. Miller, and Jimmie Powell. No date. Energy Sprawl or Energy Efficiency: Climate Policy Impacts on Natural Habitat for the United States of America. Unpublished paper. Washington, DC: Nature Conservancy.

MIT (Massachusetts Institute of Technology). 2003. *The Future of Nuclear Power: An Interdisciplinary MIT Study*. Cambridge, MA: MIT.

MIT. 2006. *The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century*. Cambridge, MA: MIT.

MIT. 2009. *Update of the MIT 2003 Future of Nuclear Power*. Cambridge, MA: MIT.

Muffler, L.P.J. (editor) 1978. *Assessment of Geothermal Resources of the United States*, US Geological Survey (USGS) Circular 790, Washington, DC: USGS.

National Renewable Energy Laboratory. No date. Learning about Renewable Energy: Solar Photovoltaic Technology. http://www.nrel.gov/learning/re_photovoltaics.html (accessed October 12, 2009).

NRC (National Research Council). 2009. *Electricity from Renewables: Status, Prospects and Impediments, America's Energy Future Panel on Electricity from Renewable Resources*. Washington, DC: The National Academies Press.

Navigant Consulting. 2008. *North American Natural Gas Supply Assessment*. Report prepared for the American Clean Skies Foundation.

Nemet, Gregory. 2006. How Well Does Learning-by-Doing Explain Cost Reductions in a Carbon Free Energy Technology? Working paper 143.06. Milan, Italy: Fondazione Eni Enrico Mattei.

Newell, Richard. 2008a. International Climate Technology Strategies. Discussion paper 08-12. Cambridge, MA: Harvard Project on International Climate Agreements.

Newell, Richard. 2008b. A U.S. Innovation Strategy for Climate Change Mitigation. Hamilton Project Discussion paper 2008-15. Washington, DC: Brookings Institution.

Palmer, Karen, and Dallas Burtraw. 2005. Cost-Effectiveness of Renewable Energy Policies. *Energy Economics* 27(6): 873–94.

Paul, Anthony, Dallas Burtraw, and Karen Palmer. 2008. Compensation for U.S. Electricity Consumers under a U.S. CO_2 Emissions Cap. Discussion Paper 08-25. Washington, DC: Resources for the Future.

Potential Gas Committee. 2009. Potential Supply of Natural Gas in the United States. Press release June 18, 2009. Golden, CO: Colorado School of Mines, Potential Gas Agency.

Samaras, Constantine, Jay Apt, Ines L. Azevedo, Lester B. Lave, M. Granger Morgan, and Edward S. Rubin. 2009. Cap and Trade is Not Enough: Improving U.S. Climate Policy. Briefing note. Pittsburgh, PA: Department of Engineering and Public Policy, Carnegie Mellon University.

Schmitt, Gary. 2006. Natural Gas: The Next Energy Crisis? *Issues in Science and Technology* 22(4): 59-64.

Short, W., N. Blair, P. Sullivan, and T. Mai. 2009. ReEDS Model Documentation: Base Case Data and Model Description. Golden, CO: National Renewable Energy Laboratory.

Small, Kenneth A. 2010. Energy Policies for Passenger Transportation: A Comparison of Costs and Effectiveness. Background paper. Washington, DC: Resources for the Future.

Stoft, Steve. 2002. *Power System Economics*. New York: Wiley.

Surek, T. 2005. Crystal Growth and Materials Research in Photovoltaics: Progress and Challenges. *Journal of Crystal Growth* 275: 292–304.

Vajjhala, Shalini, Anthony Paul, Rich Sweeney, and Karen Palmer. 2008. Green Corridors: Linking Interregional Transmission Expansion and Renewable Energy Policies. Discussion Paper 08-06. Washington, DC: Resources for the Future.

Voosen, Paul. 2009. Renewable Energy: A Cautionary Tale about Feed-In Tariffs. *Greenwire*, August 18.

Western Governor's Association. 2006. *Clean and Diversified Energy Initiative: Geothermal Task Force Report*. Denver, Colorado.

Wiser, Ryan. 2008. The Development, Deployment and Policy Context of Renewable Electricity: A Focus on Wind. Presentation at the Fourth Meeting of the Panel on Electricity from Renewables, March 11, 2008, Washington, DC.