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The Clean Power Plan and Beyond

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ABSTRACT

Since the release of the Clean Power Plan (CPP), stakeholders across the U.S. have vigorously debated the pros and cons of different options for reducing CO_2 emissions from electricity generation. This paper examines an array of CPP strategies, ranging from incremental to transformational, and from the near-term to the longer-term. The goal is to identify least-cost options to help policymakers and other stakeholders make well-informed choices. The Georgia Institute of Technology's National Energy Modeling System is used to evaluate alternative futures. Our modeling suggests that CPP compliance can be achieved cost effectively by expanding new natural gas and renewable electricity generation to replace higher emitting coal plants and by using energy efficiency to curb demand growth, thereby enabling a more affordable pace of plant replacements. Post-2030 policies requiring further CO_2 emission reductions, in combination with perfect foresight today, would motivate less natural gas build-out over the next 15 years. The South's response to the CPP is distinct, with a larger share of coal retirements and a greater proportionate uptake of natural gas, energy efficiency, and renewable resources. In addition to reducing CO_2 emissions, these least-cost compliance scenarios would produce substantial collateral benefits including lower electricity bills across all customer classes and significant reductions in local air pollution.

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Projections contained in this report are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular scenario. The Reference case projection is a business-as-usual trend estimate, given existing policies, known technologies, and technological and socio-demographic trends. The analysis explores the impacts of alternative assumptions in other cases with different policy, technology, market and resource assumptions.

Energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Some key uncertainties in the GT-NEMS projections are addressed through alternative scenarios.

We have endeavored to make these projections as objective, reliable and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

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EXECUTIVE SUMMARY

The U.S. electricity industry is in a period of unprecedented change. In response to environmental regulations, declining consumer demand, and an abundance of cheap natural gas, carbon pollution from power plants has been decreasing for nearly a decade as electricity providers retire some of their oldest, least efficient and most carbon-intensive electricity generating units (EGUs). While historic in magnitude, this pace of change is not sufficient; without additional and sustained policies, the negative consequences of climate change will continue to grow. This paper examines an array of CPP strategies, ranging from incremental to transformational, and from the near-term to the longer-term. The goal is to identify least-cost options to help policymakers and other stakeholders make well-informed choices.

The CPP aims to accelerate the current pace of electricity decarbonization by cutting CO_2 emissions from electricity generation so that by 2030 they would be 32% lower than in 2005. Recognizing the different resource endowments, preferences, industry structure, and policy environments that make each U.S. state and region unique, the CPP provides compliance flexibility. As a result, stakeholders are considering how to optimize state plans, given their unique circumstances. This paper attempts to provide helpful insights by examining the impacts of alternative CPP compliance scenarios. In addition to characterizing alternative energy portfolios that meet the CO_2 emission reduction goals, we quantify the impacts of alterative scenarios on local air pollution, electricity prices and bills as well as the associated consumer investments, the utility resource costs required to realize them, and additional economic indicators. We also examine opportunities beyond the requirements of the CPP.

Using the Georgia Tech version of the National Energy Modeling System (GT-NEMS), we examine a range of compliance scenarios. Most of our scenarios are based on mass-based carbon-reduction goals – some for existing units, others that cover both existing and new units, some with enhanced energy efficiency and solar policy assumptions and others using EIA Reference case assumptions for efficiency and renewables. In addition, we examine: (1) a hybrid case where the South adopts rate-based goals and the rest of the nation adopts mass-based goals; (2) the addition of a small carbon fee in 2022 to motivate deeper carbon reductions; and (3) extension of the CPP time horizon so that decisions based on foresight could be examined with a progressive commitment to reducing carbon pollution. Our key findings are summarized below.

Key Findings

- Mass-based carbon-reduction goals are met by all four compliance scenarios, ranging from electric sector CO_2 emission reductions of 34% in 2030 relative to 2005 when both existing and new EGUs are regulated and EE+Solar policies are added to 26% when only existing EGUs are regulated and the EE+Solar features are excluded.

- The benefits of reducing CO_2, SO_2 and NOx nearly reach $100 billion in the year 2030 (in $2013) across the CPP compliance scenarios. The co-benefits from local pollution abatement exceed the benefits from carbon mitigation.

- The CPP scenarios would double the pace of fossil-plant retirements. In 2030, 15% of the electric power sector EGUs in 2012 would be retired.

- Natural gas combined cycle units phase in rapidly as other fossil units are retired, particularly when only existing EGUs are regulated. Renewables and energy efficiency gain a larger share of the fuel mix when mass-goals for all EGUs are implemented, especially when the EE+Solar features are added. The build-up of natural gas infrastructure is therefore less challenging as resource investments become more diversified (Figure ES.1).

- Distributed and utility-scale solar grows rapidly in the Reference case and in all compliance scenarios. The additional load reduction from energy efficiency policies primarily offset the growth of natural gas generation.

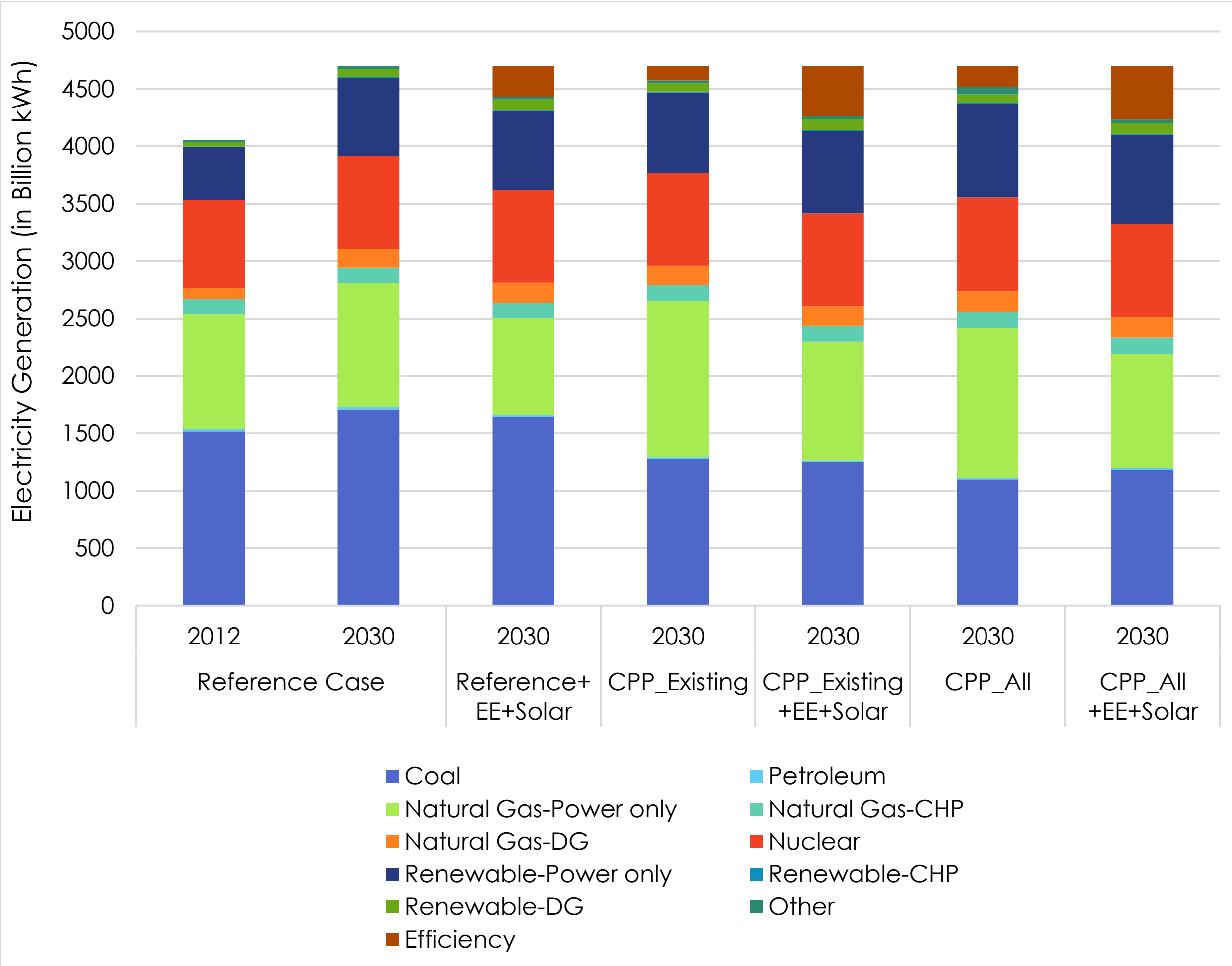
- Per capita electricity bills are forecast to increase by 12% between 2012 and 2030 (across all customer classes). Higher increases would occur in the compliance scenarios if EE+Solar features are not included. Electricity bills could drop back to 2012 levels if EE+Solar policies are added.

- Our modeling estimates that in 2030, total resource costs would be approximately 6% higher in the two CPP compliance scenarios that only cap emissions, compared with the Reference case. In contrast, they would be approximately 3% lower in the compliance scenarios that also include "EE+Solar" features.

- The fuel mix transformation over the next 15 years would be distinct with foresight that policies will require more carbon emissions reductions through 2040. Specifically, more coal would be retired and more renewable capacity would be added in the near term, thus avoiding the lock-in of fossil fuels that would increase the cost of compliance over the long term.

- The South's response to the CPP is similar to the rest of the U.S., but with some distinctions. In general, the South responds to the CPP with a greater proportion of coal retirements and a larger percent increase of natural gas, energy efficiency and renewable resources, especially wind, distributed solar, and utility-scale biomass.

Figure ES.1. Impact of CPP Compliance Scenarios on the U.S. Fuel Mix



In conclusion, CPP compliance with the enhanced deployment of energy efficiency and reduced solar costs could achieve EPA's carbon reduction goals nationwide and in the South. Along with producing a low-carbon power system, we have identified CPP compliance strategies that could produce an array of collateral benefits including lower electricity bills across all customer classes, greater GDP growth, and significant improvements in local air quality. The virtue of thinking ahead to the possibility of an additional phase of carbon mitigation has also been shown. Choices made today should avoid the legacy of building an energy infrastructure that could burden subsequent generations.

1. INTRODUCTION

1.1 The U.S. Electric Power Sector in Transition

In December 2015, world leaders met in Paris and adopted an international climate change agreement that requires deeper emissions reduction commitments from all countries, and contains provisions to hold them accountable to their commitments. This milestone in global climate negotiation was enabled by numerous precursor U.S. actions including, for instance, the President's Climate Action Plan,[1] the bilateral agreement with China, and the Clean Power Plan – the topic of this paper. The Paris Accord also benefited from a growing public recognition that climate disruption is already occurring, and a growing agreement with Pope Francis' position that "Climate change is a problem that can no longer be left to future generations."

Many states are already making progress toward cutting carbon emissions from power plants by shifting from coal-fired power to cleaner generation sources like natural gas, renewable energy, and energy efficiency. An abundance of affordable natural gas has enabled this transition, and recent Supreme Court decisions, federal regulations and state laws that predate the Clean Power Plan have further motivated utilities to generate less electricity from coal plants. Some states have already made commitments that would put them on a path to meet or exceed CPP goals.

At the same time, the U.S. electricity sector is in a period of transition and faces an array of challenges in addition to the need to reduce its carbon footprint. Sluggish demand growth and increases in distributed resources are beginning to pose problems for traditional cost recovery rate structures. In addition, the digital economy is placing greater value on power quality, and growing cyber threats are requiring increased attention to grid security. Finally, concerns over environmental quality and global climate disruption mean that the energy resources and technologies used over the past several decades to generate electricity need to be reassessed (Electric Power Research Institute, 2014; Kind, 2013).

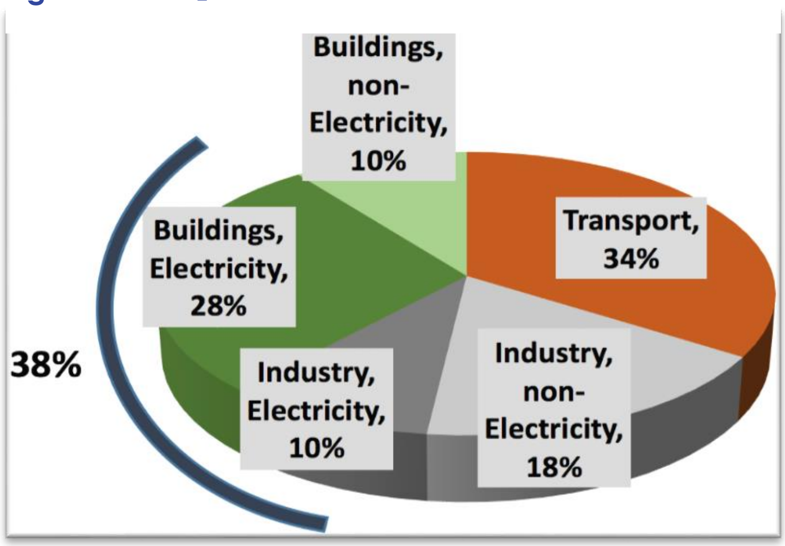
1.2 The Clean Power Plan: A Proactive Acceleration of Carbon Emissions Reductions

On October 23, 2015, the United States Environmental Protection Agency (EPA) finalized

[1] *The President's Climate Action Plan, June 2013, available at: http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf (last accessed 2/7/16).*

the first national carbon dioxide (CO_2) emission standards for power plants.[2] These standards, known as the Clean Power Plan (CPP), were developed under the Clean Air Act (CAA), an act of Congress that requires the EPA to take steps to reduce air pollution that harms the public's health and welfare. The CPP represents a significant step forward in reducing U.S. greenhouse gas (GHG) emissions. As shown in Figure 1.1, the electricity sector is responsible for 38% of U.S. CO_2 emissions, and fossil fueled power plants account for 31% of U.S. GHG emissions. The CPP requires a 32% reduction on average in the carbon intensities of affected fossil fuel-fired electricity-generating units (EGUs), relative to 2015.

Figure 1.1 CO_2 Emissions Sources in the U.S. in 2013



1.3 How will the Electric Power Sector Respond?

In the debate surrounding carbon emissions reductions, stakeholders across the U.S. have focused on the differences among U.S. states and regions that necessitate different compliance strategies. In addition, there is a sense that the CPP may be evolutionary in some parts of the country and transformational in others. The nation's electric sector is already on a path to a lower carbon future, but is the rate of reduction fast enough to address climate change? Whether the CPP will drive significant change in the electricity supply, at what cost those changes will come, and whether those changes will be enough to avoid potentially catastrophic impacts of climate disruption are questions at the forefront of policy discussions.

The analysis presented here seeks to shed light on policies that will influence power sector decision-making under the Clean Power Plan and beyond, with an emphasis on how those factors impact power sector emissions, generation portfolios, consumer bills and rates, and the economic growth. Modeling the potential impacts of the CPP and additional policies can help policymakers and stakeholders make well-informed choices about how to reduce the carbon intensity of the U.S. power supply and meaningfully address climate change.

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[2] *United States Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule" (October 23, 2015) 40 CFR Part 60, available at: https://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22842.pdsf (last accessed 2/7/16).*

2. OVERVIEW OF THE CLEAN POWER PLAN

In October 2015, EPA issued final rules for the CPP. These apply to two types of fossil fuel-fired units: electric steam generating units and natural gas combined cycle units. These affected EGUs must either reduce their CO_2 emissions or acquire credits from non-CO_2-emitting units in order to comply with the CPP. The Clean Power Plan establishes state-by-state targets for carbon emissions reductions, and it offers a flexible framework under which states may meet those targets.

The CPP is based on EPA's authority to control air pollution from stationary sources under Section 111 (d) of the Clean Air Act. While §111 (b) of the Clean Air Act (CAA) authorizes the federal government to establish standards for new, modified and reconstructed sources of CO_2 in the electric power sector, §111 (d) authorizes a state-based program for existing sources. Through the CPP, the EPA also establishes guidelines under which the states can design programs for achieving the needed reductions.

Options for cutting CO_2 emissions include investing in renewable energy, energy efficiency, natural gas, and nuclear power, and shifting away from coal-fired power. The final rule also takes steps to limit a rush to natural gas. States are free to combine any of the options in a flexible manner to meet their targets.[3] States can also join together in multi-state or regional compacts to find the lowest cost options for reducing their carbon emissions, including through emissions trading programs.

State measures are policies that are enforceable under state law. Those that can be shown to reduce emissions can contribute to the mass-based goal, because they are picking up some of the burden. The state must measure the emissions reductions, and if they cannot do that, the federally enforceable standards will be imposed as a back-stop. An RPS is a complementary measure.

2.1 Background: Climate Action at the Federal and Regional Levels

Congress has the authority to preempt the Clean Air Act through comprehensive climate legislation at the federal level, and could formulate more flexible and efficient standards of GHG regulation than would be required under the CAA.[4] Nonetheless, Congressional debates over climate legislation have, as of yet, yielded unimpressive results. Despite the

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[3] *One reason for optimism regarding the power sector's ability to meet the challenges of climate change and energy security is the wide array of fuels and technologies currently used within the industry that operate at a variety of emissions levels. Hydropower, nuclear and other renewable fuel generation (solar, biomass, geothermal, wind, tidal) operate with zero carbon emissions. However, although this may suggest a level of flexibility within the power industry, a majority of the U.S. power portfolio is currently dependent on carbon fuels. About 70 percent of the energy generated in the U.S. comes from carbon fuels (see "Electricity at a Glance:" http://nrri.org/pubs/electricity/electricity_at_a_glance.pdf).*

[4] *http://www.eenews.net/features/documents/2009/04/17/document_gw_03.pdf. As even the current EPA Administrator admitted in a hearing of the House Energy and Commerce Committee on April 22, 2009.*

U.S. Congressional failure to enact comprehensive climate legislation, growing concerns about GHG emissions are already effecting investment decisions in energy markets, particularly in the power sector.[5] U.S. power providers currently operate in a patchwork of markets, some of which are carbon-constrained, some of which are not. This is a direct result of different legislative approaches at the international, federal, regional, and state levels.

In the absence of federal guidance, some states and regions have taken the initiative to fill the legislative gap and address the challenges of climate change in a variety of ways. Direct control of GHG emissions from vehicles and major stationary sources, such as power plants, already are subject to regulation under many state initiatives. At the regional level, groups of states have banded together to form regional initiatives, such as the Regional Greenhouse Gas Initiative (RGGI) and Western Climate Initiative.[6]

Many policy mechanisms and legislative schemes for comprehensively dealing with climate change at the federal level have been suggested and, with varying success, developed by policymakers. Among the legislative mechanisms proposed for dealing with climate change are cap and trade schemes, carbon taxes, federal renewable energy portfolio standards, and mandatory command-and-control standards such as appliance efficiency standards (Brown and Wang, 2015).[7]

The ultimate goal of any climate change legislation is to create a successful regulatory regime that curbs total GHG emissions at a level that prevents disruption to the climate system (IPCC, 2014). It is also important that climate legislation efficiently and equitably spread the costs of compliance and climate abatement options, maintain public, industry and stakeholder support, avoid unintended consequences and excessive costs, and operate over the long term in order to put an effective price on the cost of emissions to the environment (Goulder and Parry, 2008). It may be necessary for climate legislation to further consider the inclusion of measures to effectively mitigate preexisting and future costs associated with damage caused by climate disruption.

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[5] *Construction of additional coal generation capacity has experienced a slump in recent years, while construction of new natural gas generation facilities has increased (EIA, 2015).*

[6] *In 2003, the Northeast and Mid-Atlantic states of Maine, New Hampshire, Vermont, Connecticut, New York, New Jersey, Delaware, Massachusetts, Maryland, Rhode Island joined to form the Regional Greenhouse Gas Initiative. The Western Governor's Association Clean and Diversified Energy Initiative is comprised of 18 Western states. Arizona and New Mexico have partnered together to form the Southwest Climate Initiative. The Northeast Regional Greenhouse Gas Initiative's (RGGI) compliance period begins in 2009. The RGGI has committed to reduce GHG emissions from power plants by 10% by 2019. The Western Climate Initiative provides administrative and technical assistance to support the implementation of state and provincial greenhouse gas emission trading programs. The State of California and the Provinces of British Columbia, Ontario, and Quebec are current participating jurisdictions (http://www.c2es.org/us-states-regions/regional-climate-initiatives).*

[7] *The Boxer-Lieberman-Warner, Bingaman-Specter, McCain-Lieberman, Sander-Boxer, Kerry Snowe, Oliver-Gilcrest, and Waxman bills are the most notable attempts by Congress to enact cap-and-trade legislation.*

2.2 Policy Framework: The Clean Power Plan Building Blocks

The CPP requirements for emissions reductions are grounded in the Clean Air Act's prescribed process for establishing emissions targets. The CAA requires that states set emissions targets that reflect the would-be outcomes of the most cost-effective, health and environment-beneficial, and otherwise attractive set of measures for reducing emissions – the Best System of Emissions Reduction (BSER). To estimate the CO_2 targets for each state, EPA uses a BSER based upon particular measures for emissions reduction that are referred to as "Building Blocks." While the estimation of each state's target is based on the BSER Building Blocks, the EPA allows states to use a wide variety of measures to achieve the targets, such as energy efficiency and nuclear power, and does not restrict states to using the BSER Building Block measures.[8]

2.2.1 Goals, the Best System of Emissions Reduction, and Building Blocks

The CPP meets the CAA's requirement for state-level targets based upon a BSER by estimating the reductions achieved through implementation of certain measures while not requiring states to use those same measures. The CAA requires that state emissions-reduction targets must reflect the emissions that would be achieved under a BSER, which accounts for costs, health impacts, and environmental impacts. As such, the EPA has set each state's CO_2 emissions target through a process that specifies a BSER. The BSER used by the EPA to estimate the opportunities for carbon-cutting consists of three "building blocks" that are described below.

Building Block 1: Operate coal plants more efficiently. Operators of coal-fired power plants can conduct heat rate improvements that allow more electricity to be produced while burning less coal. This might include improving boiler operations or optimizing cooling systems. Depending on the part of the country, EPA estimated that operators could reasonably improve coal plant efficiency by 2.1 to 4.3%.

Building Block 2: Run gas plants more often, coal less. Burning natural gas for electricity produces less CO_2 per megawatt-hour than burning coal does. So if states ran their gas plants more often and coal plants less, they could reduce emissions while generating the same amount of electricity. EPA decided it'd be reasonable for states to increase the utilization rate of their existing natural gas combined cycle fleet to 75 percent — which would curtail coal use and emissions.

Building Block 3: Ramp up renewable power. Finally, if states built more wind, solar, geothermal, hydropower, or biomass, they could reduce the overall carbon intensity of their power plant fleet. EPA conducted a detailed study of what level of renewable energy growth was reasonable in each region, based on historical trends, cost curves,

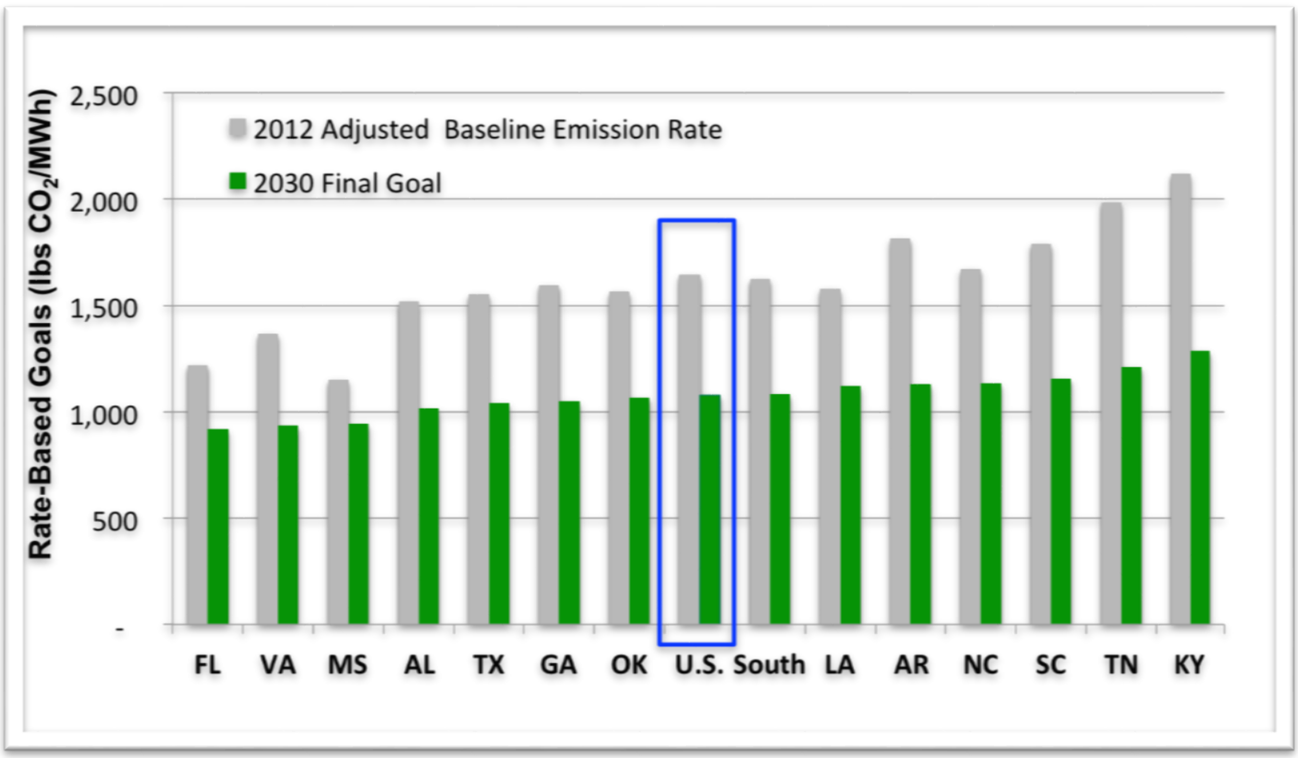
[8] For further information on the Clean Power Plan building blocks and how they relate to the CO_2 emissions goals, see the Clean Power Plan 2015 Final Rule, Section I.A.1.

grid reliability, and so forth. EPA did not assume each region would install the maximum feasible amount. Instead, it aimed for a target deemed "reasonable," cost-wise. Even so, this building block is bolder than what was in the draft proposal, in part because wind and solar prices have dropped in the past year. In setting this building block, EPA argued that it would be feasible for renewables to provide around 26% of electric generation in 2030.

Again, while the state-level targets for the CPP are set with the assumed use of the three BSER Building Blocks, states may use a wide variety of measures to achieve the CPP targets and are not restricted to the BSER Building Blocks.

2.2.2 Comparing Goals: The South and the United States

Figure 2.1. Baseline CO_2 Emission Rates and 2030 Final Goals for the U.S. and the South

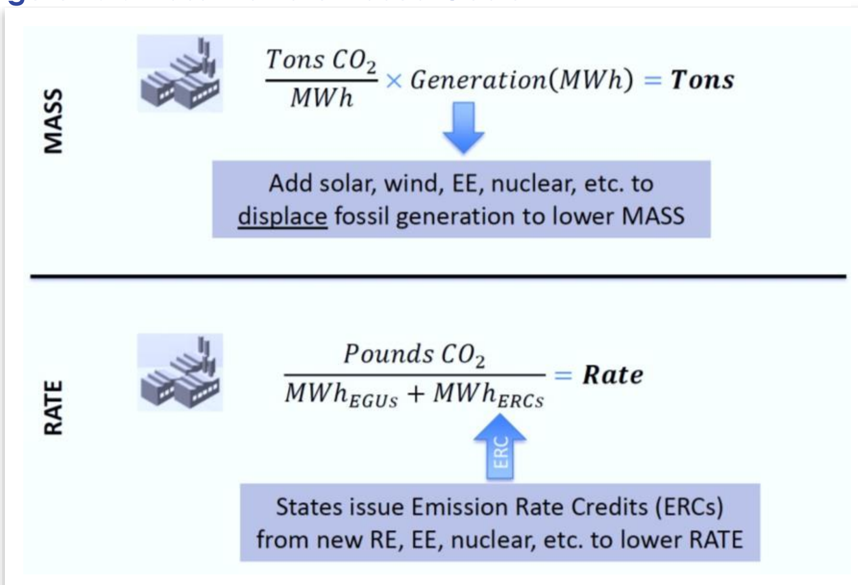


Source of 2012 Emission Rates: https://blog.epa.gov/blog/wp-content/uploads/2015/08/State-tables-tab-1.pdf

2.3 Compliance Options – Mass Goals and Rate Goals

The CPP allows states to identify the compliance pathway that best meets their objectives. In general, states are allowed to use clean energy resources in their compliance, including energy efficiency and nuclear power since they displace fossil generation and therefore displace carbon emissions.

Figure 2.2. Mass- vs Rate-Based Goals



There are four key options among which states must choose in designing their CPP compliance plans: mass-based goals for existing EGUs, mass-based goals for existing and new EGUs, subcategory-specific rate-based goals, and statewide-blend rate-based goals. Each option presents a different set of opportunities and costs for complying with the CPP, especially since there is a unique goal for each state in all options except for the subcategory-specific rate-based goal option. Both the rate-based options and mass-based options offer the potential for generating revenues through emissions permit auctioning that can be used to improve welfare in many ways (Burtraw, Woerman, and Paul, 2012). Figure 2.2 outlines the major differences between the mass-based goal options and the rate-based goal options, which are further described in the following sections.

2.3.1 Mass-based goals

States may design their implementation plans to achieve mass-based goals, measured in million metric tons of CO_2. These goals would cap emissions so that covered EGUs do not exceed a particular aggregate level of emissions rather than capping the emissions rate. In addition, this inclusion of mass-based goals aims to provide alternative option focusing on emission trading across states.

EPA has published two types of mass-based goal: one goal is based on historical emissions from existing sources, and a second goal caps existing sources and projected emissions that would result from demand growth between 2012 and 2030. For states that elect to follow a mass-based goal, compliance is measured strictly in terms of stack emissions from affected EGUs. States simply account for raw emissions when they choose a mass-based goal. They only need to show the lower emissions by applying standards on the affected EGUs. A new wind farm that meets new demand would not contribute to compliance with a mass-based goal. If it were a new natural gas plant it would not help comply with the existing mass goal. The same wind farm would contribute to compliance with a rate-based goal, and a new gas plant would be subject to 111(b) not (d).

The EPA allows states that choose a mass-based goal to trade emissions allowances with other states that have chosen the same goal – mass-based for existing EGUs only, or mass-based for existing and new EGUs – regardless of whether the states have entered into an interstate compliance agreement.

2.3.2 Rate-based goals

Rate-based goals come in two forms – statewide-blend and subcategory-specific – that offer different sets of opportunities for emissions reductions. The statewide-blend rate goals are assigned to each state based upon the BSER building blocks analysis that EPA performed for each state.[9] States choosing to pursue the statewide-blend rate goals must have the average emissions intensity rate of all of the state's affected EGUs meet the state-specific goal established by the EPA. Conversely, the subcategory-specific rates are the same throughout the nation; a rate of 1,305 lb CO_2/MWh must be met by all of a state's affected fossil-fired steam units, and another rate of 771 lb CO_2/MWh must be met by a state's affected natural gas combined cycle units.

Rate-based goals allow affected EGUs to take credit for generation provided by clean-power resources and avoided generation provided by energy efficiency programs. If energy efficiency, renewables, or nuclear power avoid fossil plant emissions, both the numerator and denominator are affected. Emission rate credits (ERC) were created by EPA to track and account for emission reductions that can be used in state-based plans.

Qualifying measures that get ERCs must be installed after 2012. In addition, they must be independently verified and tracked in an EPA-administered or EPA-approved system, and they must be registered by states. Once the ERCs are issued in a state regulatory program, the state will determine which states can obtain these ERCs through trading. While EPA does not limit the geography of the trading, ERCs can only be traded between states that that have rate-based programs. ERCs require careful measurement and tracking much like renewable energy certificates (RECs). One difference is that RECs go from a generator to a consumer, while ERCs go from a generator to a generator. The same emissions can be used for both REC and ERC issuance without double counting. The attribute included in an ERC is the avoided CO_2 emissions; they are generated by both activities that generate power and also those that avoid generation.

Only the MWh-produced or the MWh-saved, in 2022 and subsequent years count toward adjusting the rates of EGUs. Each MWh produced from an eligible measure begets an "ERC" that can be applied to the rates of affected EGUs. ERCs may be "banked," e.g. a

[9] *See the goal computation technical support document: http://www.epa.gov/sites/production/files/2015-11/tsd-cpp-emission-performance-rate-goal-computation-appendix-1-5.xlsx*

MWh from solar in 2022 can be left out of emissions rates in 2022 and instead applied to emissions rates in 2026. Only MWh's produced from units installed after 2012 may be used toward earning ERCs and subsequently adjusting rates in 2022 and later years. Also, only measures that affect the bulk electricity grid may be used for compliance; thus, installing solar off-the-grid does not count.

The choice between subcategory-specific rate goals and statewide-blend rate goals affects a state's ability to trade ERCs with one another. The EPA grants any states choosing to pursue the subcategory specific rate option the right to trade ERCs with one another, regardless of whether those states pursuing subcategory-specific rate goals enter into an interstate compact approved by the EPA.[10] Conversely, the EPA does not allow states that pursue a statewide-blend rate goal to trade with other states that make the same choice, unless those states have entered into an interstate compact that is approved by the EPA as part of the states' compliance plans.

2.3.3 Comparing mass and rate goals: Which has a lower compliance cost?

The costliness of each policy type – rate-based goals or mass-based goals – stands as a crucial consideration for states. The CPP Regulatory Impact Analysis (EPA, 2015a) suggests that mass-based goals have a lower cost of compliance than do rate-based goals. Conversely, Brown et al. (2015) found that rate-based goals offer slightly lower compliance costs. The mass-based goals may be easier to implement because they avoid the burdens of generating, tracking, and verifying ERCs as described above. The rate-based goals may offer more flexibility by allowing existing units to take credit for beyond-the-fence measures. Theoretically an efficiency measure will reduce mass emissions, although they do not receive direct credits.

If mass-based goals are chosen, allowance allocation is an important decision that states must also make; it determines how CPP costs are distributed across important constituencies. Litz and Murray (2016) describe the possibility of allocating allowances to entities operating energy-efficiency programs. As an example, the Regional Greenhouse Gas Initiative allocates allowances to the New York State Energy Research and Development Authority, which then results in investments in clean energy technologies including energy-efficiency. Additional examples of energy-efficiency set asides are provided by the NOx regulation programs in Illinois, Missouri, and Virginia (Litz and Murray, 2016).

2.4 The Clean Energy Incentive Program

The Clean Energy Incentive Program (CEIP) is a voluntary "matching fund" program that states can use to incentivize early investment in solar and wind generation, as well as demand-side energy-efficiency projects that are implemented in low-income communities. It targets projects that commence construction or operation after September 6, 2018, and produce clean energy in 2020 and 2021. EPA will provide

[10] *Such is the meaning of the "trading-ready" adjective used throughout the CPP final rule.*

matching allowances or ERCs to states that participate in the CEIP, up to an amount equal to the equivalent of 300 million short tons of CO_2 emissions. Wind or solar projects will receive 1 credit for 1 MWh of generation (i.e., half early action credit from the state and half matching credit from the EPA). Energy-efficiency projects implemented in low-income communities will receive 2 credits for 1 MWh of avoided generation (i.e., a full early action credit from the state and a full matching credit from the EPA). The ERCs earned through the CEIP are bankable, as are ERCs earned during the 2022-2030 compliance period.

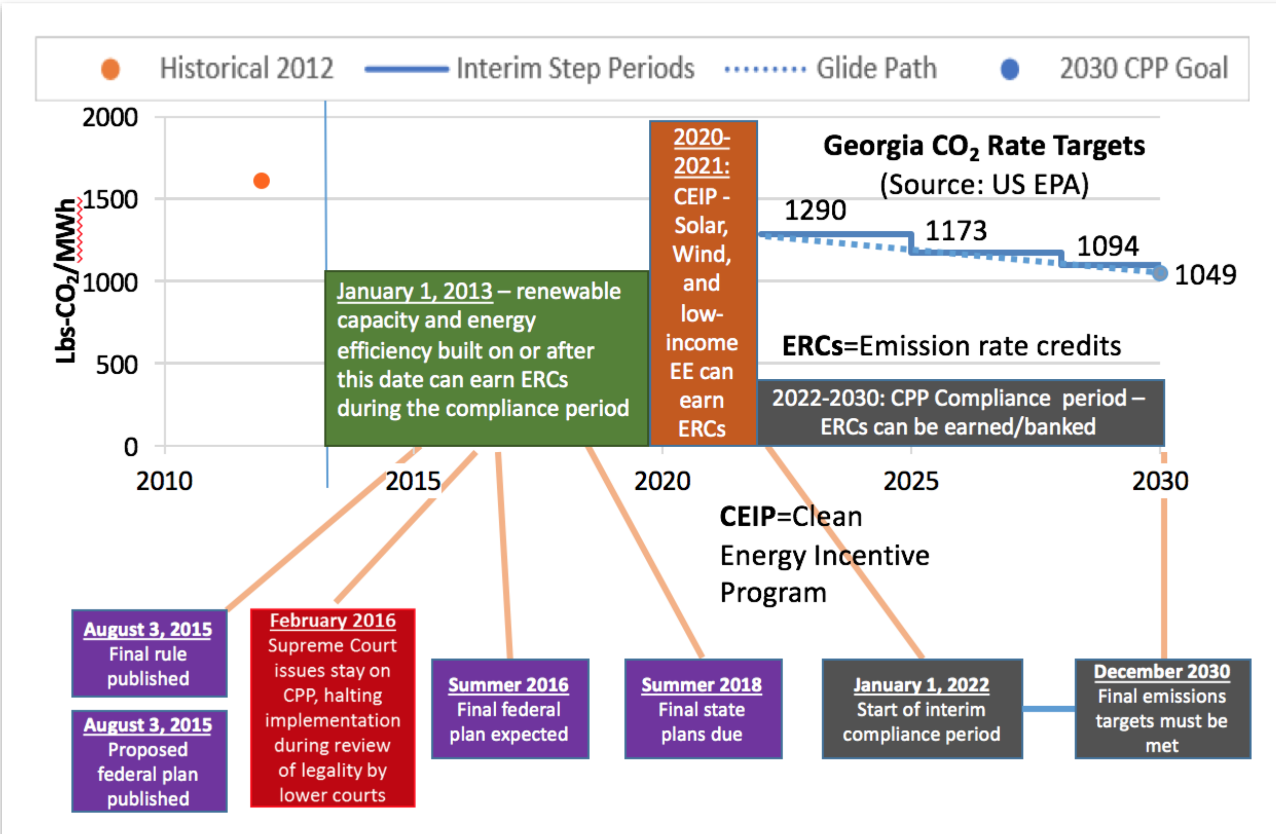
2.5 State Planning Process and Timeline

On February 9, 2016, the U.S. Supreme Court placed a "stay" on implementing the Clean Power Plan, putting a halt to the regulation while its legal fate is being decided. The request for a stay came from a coalition of 27 states including most of the states in the South. The stay was granted by the Supreme Court by a 5-to-4 majority vote. The stay stops EPA from enforcing the rule but does not bar states from moving forward. Some states are moving forward, while others are not.

Under the original plan, states were required to submit a final plan, or an initial plan with a request for an extension, by September 6, 2016. As a result of the stay, the original September 6, 2016 deadline for plans is not likely to be enforced, giving states additional time to deliberate over whether and how to comply with the CPP. Regardless of how the plan submission timeline is affected by the stay, several other elements of the CPP timeline may remain intact; for example, ERC-eligible units are to be constructed after January 1, 2013, and the compliance period is 2022-2030.

In June, 2016, the DC District court is scheduled to start hearing the case. Pending the outcome, EPA will not be moving forward to enforce the timeline. On the other hand, the agency is may continue to work on issues related to the Plan, such as the Federal Plan and Model Trading Rules proposed in late 2015 (Revesz and Walker, 2016). In the end, the stay could push back the CPP implementation timeline to allot more time for preparing plans, it could alter the timeline of compliance, and/or it could result in changes to the stringency of goals. Figure 2.3 illustrates the timeline for a hypothetical example of the plan's implementation for the state of Georgia.

Figure 2.3. Hypothetical Compliance Timeline for the State of Georgia*



3. METHODOLOGY

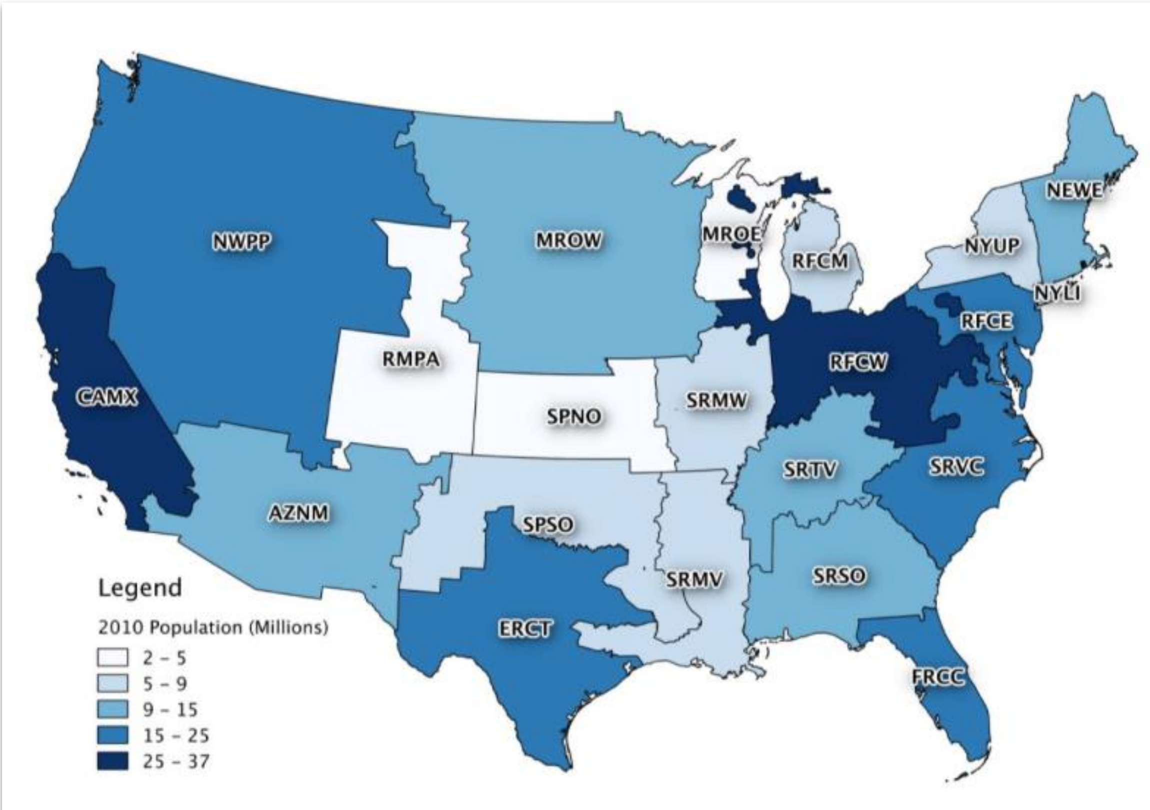
3.1 The GT-NEMS Model

The Georgia Institute of Technology's version of the National Energy Modeling System (GT-NEMS) is the principal tool used to generate the low-carbon pathways analyzed in this study to address our research questions. GT-NEMS models all sectors of the U.S. energy economy by using linear optimization to find cost-minimizing resource investments to meet energy demand growth. NEMS is "arguably the most influential energy model in the United States" (Wilkerson, Cullenward, Davidian, & Weyant, 2013). GT-NEMS is based on the version of NEMS that generated the Annual Energy Outlook 2105 (EIA, 2015a), a forecast of energy supply and demand for the U.S. through 2040. Other than modifications necessary to operate the NEMS model on networked servers at the Georgia Tech, GT-NEMS uses a Reference Case that is equivalent to the Reference Case used in the Annual Energy Outlook 2015 and is therefore described by NEMS documentation (EIA, 2015a). As explained below, alternative scenarios and CPP compliance cases are created using GT-NEMS based on modifications that intentionally diverge from assumptions in the Reference Case.

GT-NEMS is a computational general equilibrium model based on microeconomic theory. Linear programming algorithms and other optimization techniques provide the foundation with which GT-NEMS develops forecasts of the U.S. energy future. GT-NEMS uses twelve modules, plus a thirteenth integrating module, to simulate various sectors of the energy economy. These twelve sectors are each modeled by a respective module, and the corresponding twelve modules are: Macroeconomic Activity, Residential Demand, Commercial Demand, Industrial Demand, Transportation Demand, Oil and Natural Gas Supply, Natural Gas Transmission and Distribution, Coal Market, Renewable Fuels, Liquid Fuels (formerly the Petroleum Market Module), International Energy, and Electricity Market. GT-NEMS performs an iterative optimization process that results in the price and quantity that balance the demand and supply of numerous energy products. These results are intended as forecasts of general trends rather than specific predictions of future outcomes, making GT-NEMS well-suited for offering insights about alternative policy and technology scenarios.

GT-NEMS models electric power systems through a regional planning approach that makes use of one module, the Electricity Market Module, and its four constituent sub-modules. The Electricity Market Module divides the US into 22 regions based on North American Electricity Reliability Corporation (NERC) regional boundaries (Figure 3.1). The Electricity Market Module performs separate projections of power demand and the cost-minimizing supply necessary to meet that demand for each region. In computing estimates of cost-minimizing supply choices, the Electricity Market Module uses survey data from EIA's Form 860, 861, and 923 surveys, as well as NERC projections and data from the Federal Energy Regulatory Commission's Form 1 survey. These inputs are used to characterize end-use load shapes, costs and performance of capacity types, and other key variables within the Electricity Market Module.

Figure 3.1. The Electricity Market Module's NERC Regions and Their Populations in 2010



(Source: Benjamin Staver, Georgia Institute of Technology)

GT-NEMS uses the 22 regions defined by the North American Electric Reliability Corporation (NERC) to forecast electricity supply and demand (See Appendix Table App.1 for the geographic names of these regions). The seven NERC regions comprising the South include four divisions of the Southeast Reliability Council (SRDA–Mississippi Delta, SRCE–Tennessee Valley, SRSE–Georgia-Alabama, and SRVC–Virginia-Carolina), SPPS–Southern Plains, TRE–Texas, and FRCC–Florida. The demand-side modules of GT-NEMS are based on data for nine Census Divisions, including three that cover 16 states in the South and the District of Columbia (DC). With these geographic regions GT-NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions about macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics (EIA 2009; 2015c).

3.2 Design of Scenarios for Modeling CPP Compliance

Our analysis of the impact of the Clean Power Plan begins by considering EIA's *Annual Energy Outlook 2015* Reference Case. This case is assumed to be the baseline forecast of the U.S. energy system in the absence of the Clean Power Plan.

This Reference case is then modified in steps to update assumptions about various resource costs, technology performance, and future policies. The first alteration involves adding more aggressive assumptions about energy efficiency and solar power (the "EE+Solar" assumptions). These assumptions are summarized in Table 3.1. The EE+Solar changes are introduced throughout the planning period representing progressive improvements in energy-efficiency and solar technologies and additional policies.

In the residential sector, we strengthen the representation of equipment and appliance standards in NEMS in several targeted areas. Many of these same efficiency improvements are modeled by Bianco, et al. (2013) and/or by the NEMS 2014 High Technology "side case". Significant improvements in appliance standards are modeled for room air conditioners as well as refrigerators and freezers. Geothermal heat pumps, electric water heaters, dishwashers, and gas and electric clothes dryers. For lighting we apply the High Tech side case" assumptions for costs and efficiency, improving bulb type LEDs, reflector LEDs, linear fluorescent bulbs and LEDs, and LED torchieres. Miscellaneous electric uses are also made more efficient by adopting the High Tech side case assumptions upgrading the efficiency of home theater systems, ceiling fans, coffee makers, and dehumidifiers. Consistent with the CEIP incentives to improve demand-side energy efficiency, especially for low-income communities, shell thermal efficiencies in single-family homes, apartments, and mobile homes are also improved, mirroring the impacts of stronger state building codes.

In the commercial sector, stronger state building codes and other energy-efficiency policies are proxied by strengthening the envelope efficiency of new buildings and by using the AE02014 High Technology "side case" assumptions. In addition, two new high-efficiency air source heat pump technologies are added to the array of commercial HVAC options. These advanced technologies will benefit from the recent promulgation of a new efficiency standards for commercial air conditioners and furnaces – the largest energy-saving building equipment standard in U.S. history[11] – that is to be implemented in two phase: in 2018 they will deliver a 13% improvement in the energy efficiency of products, and in 2023, an additional 15% efficiency improvement will be required for new commercial units. We model the new standard by eliminating the noncompliant rooftop equipment in 2018 and 2023. We also decrease the discount rates used by commercial consumers of new air conditioning and lighting technologies in new and existing buildings.

In the industrial sector, stronger state energy-efficiency policies are modeled by including additional energy-efficiency assumptions related to combined heat and power (CHP) and electric motors. The scenario assumes 30 percent investment tax credits for CHP through 2040, accelerated cost decline--the rate of decline for CHP system costs is increased. In addition, EIA's High Technology assumptions are used, which triggers increases in the speed of cost declines for CHP systems. The High Tech case also assumed improved electric motor efficiencies. Further, we assume that policies encourage

[11] http://energy.gov/articles/energy-department-announces-largest-energy-efficiency-standard-history

manufacturers in five industrial subsectors to reduce their unit energy consumption (UEC) below Reference Case projections. These produce energy consumption reductions in 2030 that range from 18 percent for bulk chemicals, 23 percent for cement and refining, 40 percent for pulp and paper, and 57 percent for iron and steel (Brown, Cox, and Cortes, 2010). Many of these same efficiency measures are modeled by Bianco, et al. (2013).

Table 3.1. The Reference Case and Alternative Energy Efficiency + Solar Assumptions

Scenario	Description
Reference Case	Annual Energy Outlook 2015 Reference Case.
Reference+EE+Solar	Strengthened residential building equipment and appliance standards in targeted areas including room air conditioners, water heaters, a variety of types of lighting, and various miscellaneous energy uses such as home theater systems and ceiling fans; improved building shells to model better building codes and the CEIP.
	Commercial energy-efficiency improvements including higher-efficiency space heating and cooling equipment with stronger standards for rooftop units beginning in 2018 and again in 2023, lower discount rates for commercial consumers of air conditioning and lighting; and tighter building shell requirements.
	Industrial energy-efficiency includes a 30 percent investment tax credits for large-scale (40 MW+) CHP through 2040, the EIA's High Technology assumptions for CHP systems and electric motors, and process efficiency improvements in five manufacturing subsectors.
	The "EE+Solar" changes are introduced throughout the planning period representing progressive improvements in energy-efficiency and solar technologies and additional policies: extension of the Production Tax Credit for wind energy and extension of the Investment Tax Credit for solar energy with a higher incentive in 2020-21 to model the CEIP.
	Updated cost of installed utility-scale, residential, and commercial solar PV systems based on estimates from GTM/SEIA, Bloomberg New Energy Finance, Deutsche Bank, and national laboratories.

To update estimates of solar PV costs in the NEMS model, we reviewed a diverse range of contemporary estimates of solar PV costs. The sources reviewed included GTM/SEIA (2015a, b), Bloomberg New Energy Finance, Deutsche Bank, and national laboratories (Barbose and Darghouth, 2015; Bolinger and Seel, 2015).

We also model the extensions of the wind production tax credit (PTC) and the solar investment tax credit (ITC) that were implemented by the Consolidated Appropriations

Act in 2015.[12] The PTC provides a 2.3 cent per kWh tax credit for the first 10 year of production for plants that are under construction by the end of 2016. The PTC was extended for five years, but the value of the credits decline over the 5-year period. The ITC provides a 30% tax credit for the cost of developing solar energy projects through 2019, when the credit declines incrementally until 2022, when it expires for residential projects and drops to 10% for utility and commercially operated solar projects.

To reflect the Clean Energy Incentive Program, we further adjusted the solar and wind energy cost assumptions. The CPP's Clean Energy Incentive Program (CEIP) provides additional incentives for wind and solar energy resources by granting emissions allowances to solar and wind projects that provide energy to the grid in 2020 and 2021, before the CPP starts in 2022. Solar and wind energy resources can sell the credits earned through the CEIP in order to reduce financing burdens, and through this mechanism, the CEIP increases the economic competitiveness of wind and solar energy.

We also model the CEIP by slowing the rate of decline in the ITC for solar energy and the PTC for wind. Whereas the ITC for solar is currently set to be 26% in 2020 and 22% in 2021, we maintain an ITC of 30% in 2020 and 2021 to reflect the economic advantages to solar under the CPP's CEIP. Similarly, we model a PTC during 2019, 2020, and 2021 that is 60% of the 2016 PTC value to reflect the economic advantages to wind energy under the CEIP.

3.2.1 Analyzing a Mixture of Clean Power Plan Compliance Pathways

In addition to the Reference Case and the Reference+EE+Solar Case, we examine several pairs of scenarios that meet CPP compliance. The first pair uses the NEMS mass constraints for "Existing" EGUs – one without and the other with the EE+Solar assumptions. The second pair uses the NEMS mass constraints for Existing + New or "All" EGUs – one without and the other with the EE+Solar assumptions, as summarized in Table 3.2 and described below. In addition, two scenarios are analyzed that enable an assessment of the shadow price of CO_2 emission reductions and the leakage cross-state emissions spillover that could occur when there is a mix of mass- and rate-based CPP compliance pathways. These are described in Table 3.2. The four principal compliance scenarios are shown in Figure 3.2.

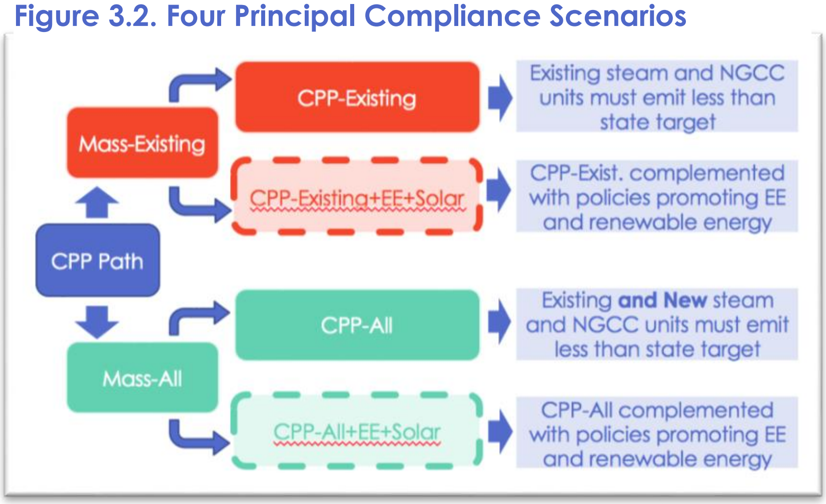
[12] http://www.eia.gov/todayinenergy/detail.cfm?id=26492

Table 3.2. Alternative Compliance Scenarios

Scenario	Description
CPP-Existing	CPP state-level goals for CO_2 mass emissions from existing EGUs (as described in the the EPA CPP Technical Support Document) are modeled directly by specifying constraints on emissions in the Electricity Market Module. Constraints at the state level are aggregated into the 22 NERC region constraints using weights based on a matrix of state-to-NERC-region generation in 2012.
CPP-Existing+EE+Solar	"EE+Solar" features added to the "CPP-Existing" compliance scenario.
CPP-All	CPP state-level goals for CO_2 mass emissions from existing and new EGUs are modeled directly by specifying constraints on emissions in the Electricity Market Module (EMM). Constraints at the state level are aggregated into 22 NERC region constraints using weights based on a matrix of state-to-NERC-region generation in 2012.
CPP-All +EE+Solar	"EE+Solar" features added to the "CPP-All" compliance scenario.
Beyond CPP Existing	Same as "CPP-Existing+EE+Solar," except a $20-ton price on carbon is applied to all electricity sector activities from 2031-2040.
Beyond CPP All	Same as "CPP-All+EE+Solar," except a $20-ton price on carbon is applied to all electricity sector activities from 2031-2040.
CPP-All+$20fee+EE+Solar	Same as "CPP-All+EE+Solar," except a $20-ton price on carbon is applied to all electricity sector activities in 2022.
CPP-Mix+EE+Solar	Same as "CPP-All+EE+Solar," except that seven regions representing the South comply with rate-based CPP goals instead of mass-based CPP goals.

An additional scenario, "CPP-Mix+EE+Solar," serves to illustrate the impacts of a mixture of compliance plans chosen by the states. In particular, the "CPP-Mix+EE+Solar" scenario features states in the South choosing to pursue rate-based goals while states outside of the South choose to pursue mass-based goals. Here, the South is defined by the seven NERC regions listed earlier. In GT-DSM, the demand-side modules are

Figure 3.2. Four Principal Compliance Scenarios



based on data for nine Census Divisions, including three that cover 16 states in the South and the District of Columbia (DC).

3.2.2 Analyzing Emissions Reductions Beyond the Clean Power Plan

Additional scenarios are used to examine CO2 reduction potentials beyond the Clean Power Plan. In each of these, a $20 carbon fee is applied to power generation in the electricity sector, and the fee escalates over time to track inflation, counter discounting, and encourage further reductions.

Two of these scenarios initiate a $20 carbon fee in 2031 and sustain it through 2040 to examine the investment patterns and fuel portfolios that would occur in the CPP compliance period if there were a commitment to continue the downward trajectory of carbon emissions beyond the time horizon of the CPP. Forward-thinking governors and industry leaders will likely look ahead to such a possibility in order to plan for least-cost options, should climate change regulations or legislative initiatives continue beyond 2030. These "Beyond CPP" scenarios start with the "CPP+EE+Solar" cases, and add the tax in 2022, creating the "Beyond CPP Existing" and the "Beyond CPP All."

The third scenario assumes that additional policies result in additional costs associated with carbon emission reductions in the power sector, beginning in 2022. These additional costs are layered on top of the "CPP-All+EE+Solar" case, resulting in the "CPP-All-$20fee+EE+Solar" case. In addition to characterizing the kinds of investment shifts that would result if the market signals for carbon emission reduction were strengthened, this scenario also allows us to estimate the marginal cost of compliance. The additional CO2 reductions that occur with the stronger price signal will be proportionate to the marginal cost of compliance. Since regions have varying compliance costs, this scenario enables an assessment of the geography of opportunities for further reductions.

3.3 Calculating Mass Emission Reduction Goals for Measuring Compliance

After running GT-NEMS with these assumptions, we calculate the CO_2 mass reductions for the U.S., and the 22 NERC regions. This allows us to examine the projections relative to the two types of mass-based goals discussed by EPA: one for existing EGUs and the second for existing and new EGUs.

3.4 Apportioning State Goals to Modeling Regions

Because GT-NEMS uses the 22 NERC regions to forecast electricity supply and demand, the state-level goals defined in the CPP need to be apportioned to regional levels. Plant-level generation data for 2012 are used to weight the state 2030 goals of the Clean Power Plan. The weights for calculating regional mass-based goals and rate-based goals are based on the percentage of each state's electricity generation in 2012 that were located in the region. For example, 99% of Texas's 2012 generation occurred in the TRE region, so in calculating the mass-based goal for the TRE region the mass-based goal for Texas receives a weight of 0.99. In calculating the rate-based goals, a reverse-weighting procedure is used. Taking the TRE region again as example, only 83% of the total generation in TRE comes from Texas. As such, the mass-based goal of Texas receives a weight of 0.83 when calculating the rate-based goal for TRE.

4. IMPACTS ON EMISSIONS AND THE ENERGY PORTFOLIO

4.1 Impact of CPP on CO_2 Emissions and Criteria Pollution

4.1.1 Estimated reductions

In the absence of new policies, CO_2 emissions from the power sector are forecast to increase steadily through 2040, at an average annual growth rate of 0.2% (Table 4.1 and

Figure 4.1). This projected growth rate is slower than the assumed rate of growth of the population (at 0.7%) and GDP (at 2.4%) (EIA, 2015a). As a result, CO_2 emissions per capita and the carbon intensity of the economy are forecast to continue to decrease, as has been the trend for more than a decade.

Table 4.1. CO_2 Emissions Across Scenarios, by Scope: Existing EGUs, All EGUs, and Sector-Wide (Million Short Tons, Lower 48 State)*

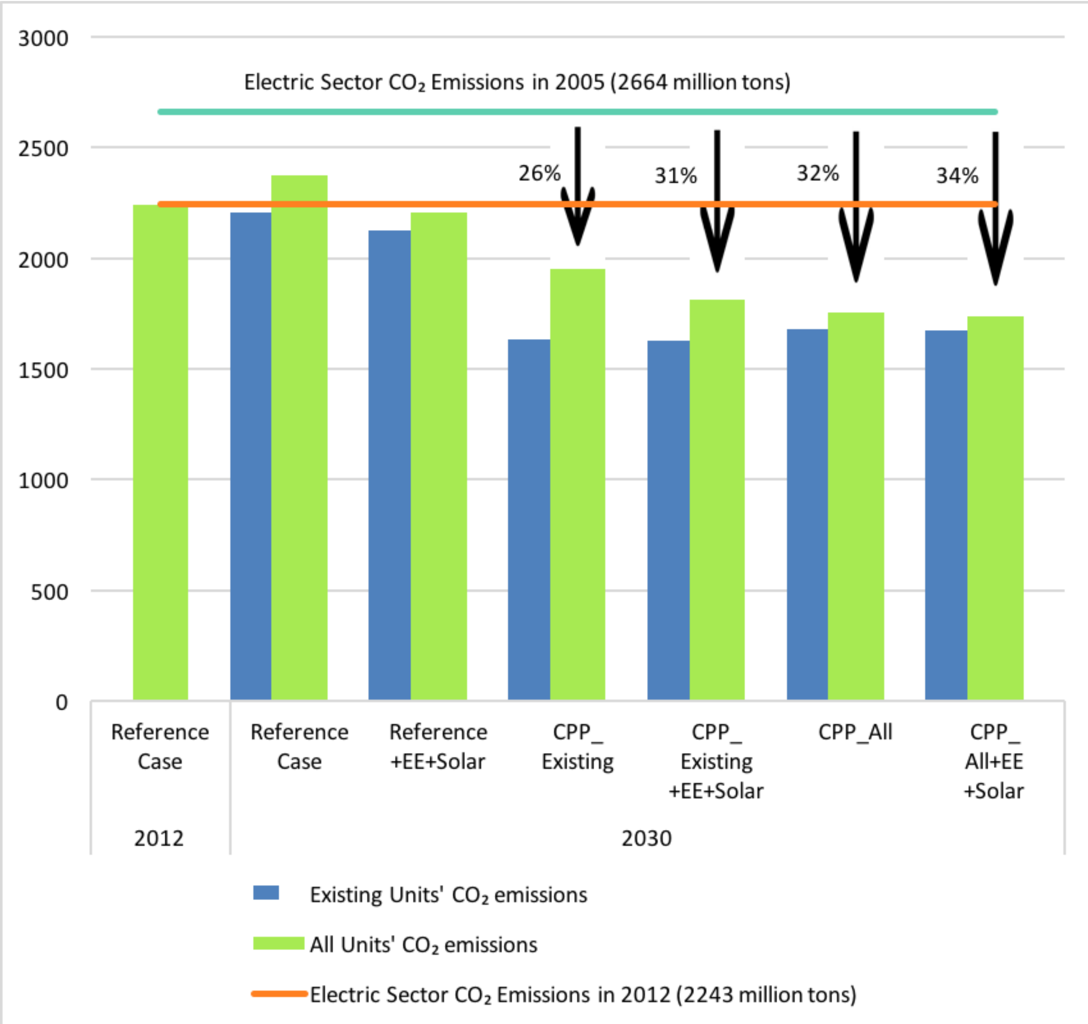
	2005	2012	2030				
					Electric Sector		
Scenarios	**Electric Sector Total**	**Electric Sector Total**	**Affected Existing EGUs**	**All Affected EGUs (Existing & New)**	**Total**	**% Reduction from 2005**	
Reference Case	2664	2243	2208	2374	2400	9.9%	-7.0%
Reference+EE+Solar	2664	2243	2157	2238	2232	16.2%	0.5%
CPP-Existing	2664	2243	1632	1954	1979	25.7%	11.8%
CPP-Existing +EE+Solar	2664	2243	1627	1812	1834	31.2%	18.2%
CPP-All	2664	2243	1681	1757	1802	32.4%	19.7%
CPP-All +EE+Solar	2664	2243	1676	1736	1762	33.9%	21.4%
Beyond CPP Existing	2664	2243	1621	1786	1807	32.2%	19.4%
Beyond CPP All	2664	2243	1672	1729	1752	34.2%	21.9%
CPP-All-$20fee+EE+Solar	2664	2243	1615	1671	1659	37.7%	26.0%
CPP-Mix+EE+Solar	2664	2243	1583	1637	1695	36.4%	24.4%

**A metric ton (1,000 kilograms) is 1.10231 times larger than a short ton (2,000 pounds).*
Source: Graf2000 Table 109, Rows 333-334 and Table 117, Row 8

Following the global economic downturn of 2008 and fuel switching away from coal to low-cost natural gas, the U.S. experienced a decline in CO_2 emissions: thus, the electric sector in 2012 emitted 2,243 short tons of CO_2, down 16% from the 2,664 tons of emissions in 2005. But as the economy expands going forward, EIA forecasts that CO_2 emissions will rise to 2,400 short tons in 2030 and 2,422 short tons in 2040. These are 7% and 8% increases over CO_2 emissions in 2012. Emissions do not return to 2005 levels over the 25-year horizon of the *Annual Energy Outlook 2015*, according to EIA's Reference case forecast, producing an upward trajectory of CO_2 emissions that is inconsistent with long-term climate change goals.

The CO_2 emissions that could result from a range of alternative scenarios are shown in Table 4.1. The scenario that limits emissions from both existing and new EGUs and also has energy efficiency and solar cost and policy assumptions (that is, the "CPP-All+EE+Solar" scenario) would result in power sector CO_2 emissions of only 1,762 short tons in 2030, 34% less than in 2005 and 21% less than in 2012. Without the EE+Solar features, the "CHP-All" scenario reduces CO_2 emissions by 32% relative to 2005 and 20% relative to 2012. EPA (2015a)'s *Regulatory Impact Analysis* projected that the CPP would achieve a 32% reduction relative to 2005, and this is what GT-NEMS estimates when the CPP mass constraints for all affected EGUs are layered onto the EIA Reference case.

Figure 4.1. CO_2 Emissions Across Scenarios, by Scope of Mass-Based CPP Compliance



Source: Graf2000 Table 109, Rows 333-334 and Table 114, Row 8

Electric-sector emissions are higher when only the existing affected EGUs are regulated. For example, the "CPP-Existing+EE+Solar case" results in electric sector emissions of 1,834 short tons of CO_2, representing a reduction of 31% relative to 2005 and 18% less than in 2012. When the EE+Solar features are removed, the "CPP-Existing" scenario results in 1,979 short tons of CO_2 emissions in 2030, representing reductions of only 26% and 12% less than in 2005 and 2012, respectively. The migration of emissions from covered (existing) sources to non-covered (new) sources – called leakage – is the most likely explanation for the higher sector-wide emissions when only existing sources are regulated.

Leakage is defined by EPA as a shift in emissions within a state from covered fossil generators to uncovered fossil generators. Leakage is motivated by the fact that existing steam EGUs and combined cycle natural gas plants face a cost under a mass system that new NGCCs do not. It occurs when there is "a larger incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs relative to what would occur when the implementation of the BSER took the form of standards of performance…."[13] For example, leakage would occur if the CPP caused electricity generation to be dispatched less from existing coal plants and more from a new (non CPP-regulated) natural gas combined-cycle units, rather than utilizing low-carbon resources such as renewables, nuclear and energy efficiency.

Litz and Murray (2016) describe a hypothetical situation where an existing coal unit does not dispatch and therefore does not count against the state's carbon cap. Allowances that the state might have used are therefore available to be used to dispatch from other covered existing units. The result is that emissions are shifted but are not reduced. If the case results in redispatching from covered to uncovered capped new gas sources, total carbon emissions could rise. Thus, the environmental integrity of the CPP is compromised by leakage.

Figure 4.2. CO_2 Leakage when Existing Units are Regulated

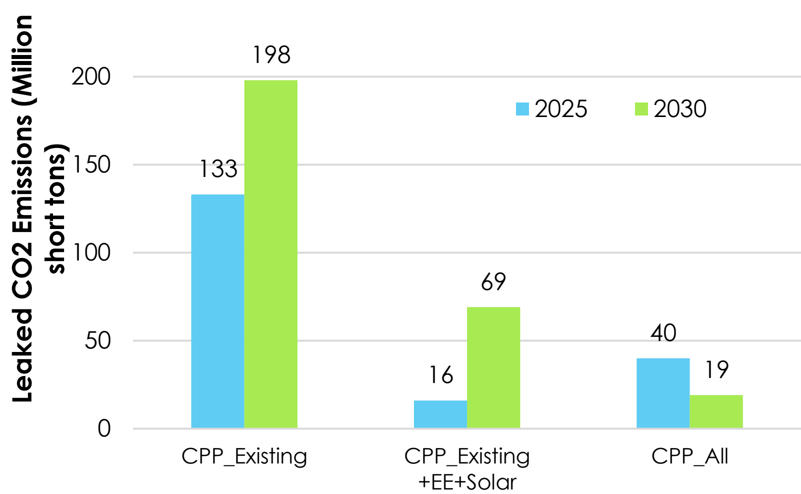


Figure 4.2 quantifies the extent of leakage that could occur with the implementation of mass-based goals regulating only affected existing EGUs. The extent of leakage is estimated by comparing three compliance scenarios with results from the "CPP_All+EE+Solar" scenario. Leakage in 2030 ranges from 198 million short tons of CO_2 in the "CPP-Existing" case and 69 million tons in the "CPP_Existing+EE+Solar" case to just 19 million tons in the "CPP-All" case when "EE+Solar" is not included.

These results indicate that the likelihood of leakage is reduced by measures that decrease future demand such as energy efficiency and by actions that depress clean energy prices such as the PTC/ITC and CEIP. Both the energy-efficiency policies and tax extenders dampen the demand for fossil fuels more in the 2020-2025 time frame than in later years, which is why leakage grows over time in the "CPP_Existing+EE+Solar" case. Other methods to address leakage have been suggested by Litz and Murray (2016) and Butraw, et al. (2016). EPA requires states that adopt mass-based plans to adopt leakage-

[13] Proposed Federal Plan and Model Rules, supra note 3 at 65019.

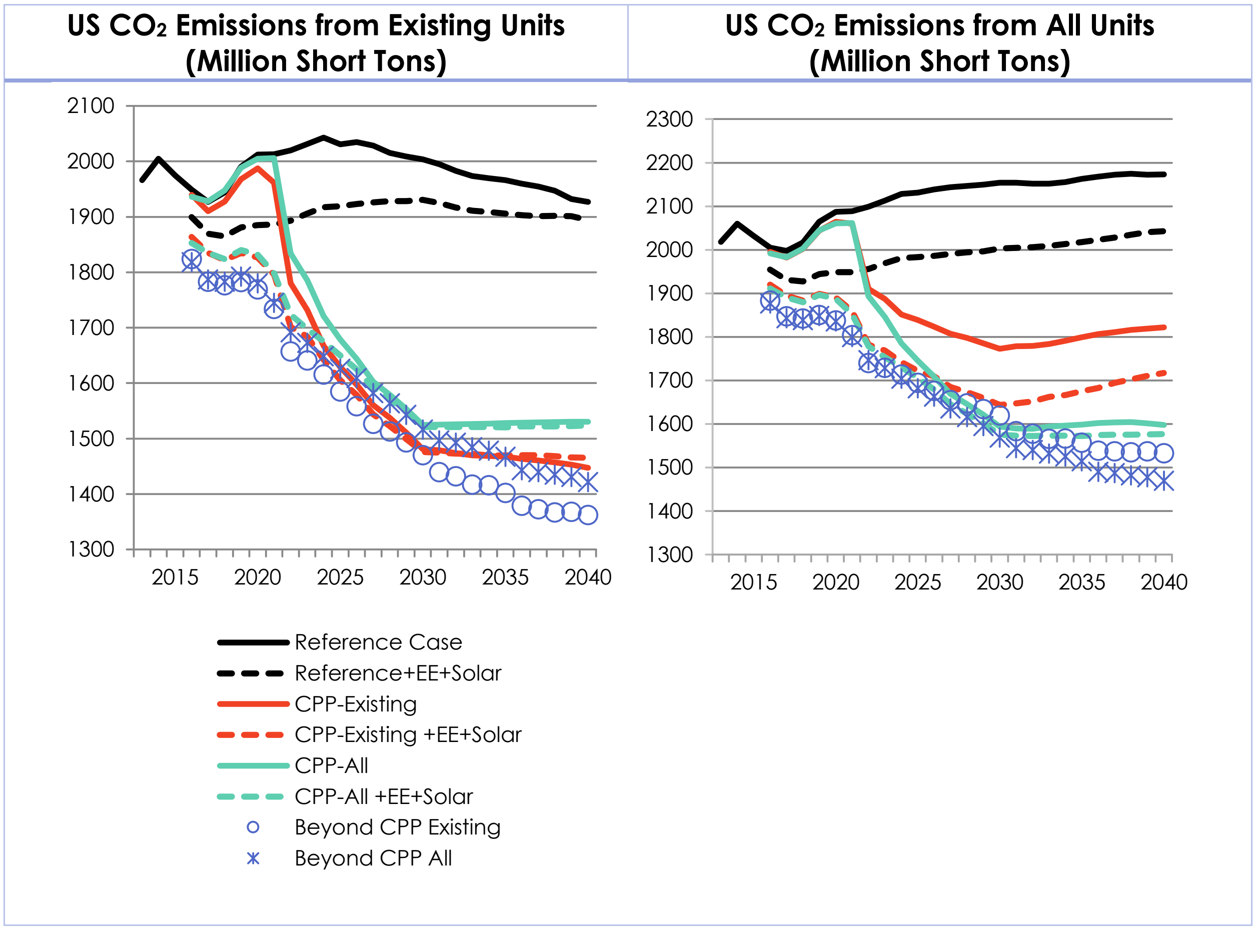
mitigation strategies.

Other leakage-related issues that are more difficult to test, also need to be addressed. These include when a coal unit in a mass-based state reduces its operations, and a neighboring state with a rate-based goal replaces that generation with a new NGCC plant. It is unclear that this type of geographic leakage can be tracked, and if it could be identified, it is not clear which state would be responsible for accounting for the emissions from the new NGCC plant. In any event, interstate leakage is not addressed in the CPP, because EPA is limited by the CAA to setting requirements only within states (Larsen, et al., 2016a).

Figure 4.3 shows the timeline of CO_2 emission reductions that occur from an array of compliance strategies. It distinguishes between emissions from plants that are affected by the Clean Power Plan and all plants, which include fossil units such as combustion turbines. Emissions for affected units decline steeply from 2022 through 2030, the compliance period, when the CPP mass-based goals are imposed when the CPP mass-based goals are imposed as a standalone policy. They begin to decline earlier under all of the other scenarios, particularly when the $20 value is placed on a ton of CO_2 in the year 2022. They continue to decline rapidly only when policies continue to motivate reductions after 2030. The "Beyond-CPP-Existing" scenario produces the deepest reductions from affected plants in 2040.

Most of the scenarios see an upward tick in CO_2 emissions after 2030. The greatest reductions in 2040 occur with the implementation of goals on all affected units in combination with placing an additional value on emission reductions through 2040 and adding the EE+Solar features.

Figure 4.3. Trajectories of CO_2 Emissions



Note: Million short tons in lower 48 states. Source: Graf2000 Table 109, Rows 333-334

4.1.2 Estimated Climate Benefits and Co-Benefits

Implementing the Clean Power Plan is expected to reduce emissions of CO_2 and produce co-benefits associated with lower local air pollution. This section estimates these monetized climate benefits and air pollution health co-benefits. The estimated benefits are beyond those achieved by previous EPA rulemakings, including the Mercury and Air Toxics Standards (MATS), and other policies already promulgated, since these effects are built into the EIA Reference Case.

We estimate the global social cost of carbon (SCC) using EPA's "Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants" (EPA, 2015a). The SCC is a metric that estimates the monetary value of impacts associated with CO_2 emission reductions in a given year. We focus on the single year 2030. The SCC includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. EPA offers four alternative estimates of the SCC using different discount rates (2.5%, 3%, and 5%) applied to model average values as well as a 3% rate applied to the 95th percentile model value. We use the 3% discount rate applied to a ton of CO_2 emissions in 2030, which corresponds to $55 (in $2011) per metric ton of CO_2 as reported in EPA (2015) Table 4-2. This value equates to $51.7 (in $2013) per short ton of CO_2 in 2030.

Beyond achieving compliance with the goals of the Clean Power Plan, the CPP compliance scenarios offer additional environmental and health benefits, which are called co-benefits because they are not the primary benefit being targeted by the CPP. The most studied of these co-benefits are the criteria air pollutants that are reduced when fossil-fuel electricity generation decreases. These include sulfur dioxide (SO_2), nitrogen oxide (NOx), PM10, PM2.5, NH_3, VOCs, and mercury. A set of recent studies estimates that the annual cost of these air pollutants from power generation in the U.S. ranges from $72 to $170 billion ($2010) (Massetti, et al., 2016; NRC, 2010; IEC, 2011; Muller, Mendelsohn, and Nordhaus, 2011, and Muller and Mendelsohn, 2007). Additional costs of fossil-fuel power generation are land use impacts and solid waste including coal combustion by-products and toxic wastes such as PCBs and neurotoxins used in flame retardants and power electronics (Brown, et al., 2016). These additional costs are difficult to monetize and have not been examined thoroughly in the literature to date. GT-NEMS generates estimates of SO_2, NOx, and mercury emissions for both the Reference case and the five alternative scenarios. Thus, we focus on these co-benefits.

Table 4.2 shows the emissions of these criteria pollutants in 2012 and 2030, as well as how those pollutant levels change over the scenarios.

EPA's "Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants" (EPA, 2015a) provides a range of benefits-per-ton of SO_2 and NOx emitted from EGUs operating in 2030. These monetized co-benefits incorporate the conversion from precursor emissions to ambient fine particles and ozone. The range of co-benefit estimates reflects the range of epidemiology studies for avoided premature mortality for PM2.5 and ozone. The monetized co-benefits do not include reduced health effects from direct exposure to NO_2, SO_2, ecosystem effects, or visibility impairment. Co-benefits are based on regional benefit-per-ton estimates, since benefits vary depending on the location and magnitude of their impact, which drive population exposure. Co-benefits for ozone are based on ozone season NOx emissions. The estimates we use for valuing reductions in SO_2 and NOx are the national numbers shown in Table 4-3 of EPA (2015).

Table 4.2. Electric Power Sector Emissions in the U.S. in 2012 and 2030*

	Carbon Dioxide		Sulfur Dioxide		Nitrogen Oxide		Mercury	
Scenario	Million Short Tons	% Change	Million Short tons	% Change	Million Short tons	% Change	Short tons	% Change
Reference Case								
2012	2,243		3.43		1.68		26.69	
2030	2,400		1.43		1.57		6.43	
Compliance Scenarios								
Reference Case +EE+Solar	2,231	7%	1.37	4%	1.46	6%	6.14	4%
CPP-Existing	1,978	18%	1.03	28%	1.14	27%	4.83	25%
CPP-Existing +EE+Solar	1,801	25%	0.88	39%	1.00	36%	4.15	36%
CPP-All	1,833	24%	1.00	30%	1.08	31%	4.74	26%
CPP-All+EE+Solar	1,761	27%	0.93	35%	1.04	34%	4.45	31%
Beyond CPP Existing	1,807	25%	1.00	31%	1.07	32%	4.73	26%
Beyond CPP All	1,752	27%	0.93	35%	1.02	35%	4.44	31%

**Based on emissions from affected electricity generating units. "% Change" is based on the difference between the compliance scenario in 2030 and the Reference case forecast for 2030.*
Source: Graf2000 Table 117, Rows 3, 4, and 8

EPA (2015a) does not provide a monetary value for mercury abatement. As a result, we do not include the significant reduction of mercury in our assessment of co-benefits.

We combine estimates of air pollution emissions with the benefits-per-ton of reduced CO_2, SO_2 and NOx shown in Table 4.3 to estimate the benefits of decreasing these air pollutants in the year 2030. Our calculations use the methodology developed by EPA in its final CPP Regulatory Impact Analysis (EPA, 2015a).

Across the four compliance scenarios, the estimated value of reduced local air pollution exceeds the estimated value of reduced CO_2 emissions. The benefit per ton of CO_2 abated is $51.7 (in $2013) based on EPA (2015). The total benefit when the values for SO_2 and NOx are added range from $97-$163 per ton CO_2 abated in the "CPP-All" Scenario to $105-$183 in the "CPP-All+EE+Solar" compliance case. In total, the benefits of reducing CO_2, SO_2 and NOx in the year 2030 range from $13 to $19 billion (in $2013), when comparing the outcomes of the Reference Case with "EE+Solar" relative to the EIA Reference Case forecast. The CPP compliance scenarios evaluated in Table 4.3 would produce estimated co-benefits ranging from $45 to $110 billion (in $2013). This is more than the estimate of \$33 billion to \$86 billion (in \$2012) of these same pollutants (CO_2, SO_2 and NOx) in 2030 provided by M.J. Bradley (2015, p. 20).

Table 4.3. Total Benefits of Reducing Carbon Dioxide, Sulfur Dioxide, and Nitrogen Oxides in 2030

Monetized benefits in 2030 (in billions \$2013)	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxide	Total
Reference Case+EE +Solar	9	3 - 6	1 - 4	13 - 19
CPP-Existing	22	18 - 42	5 - 16	45 - 80
CPP-Existing+EE +Solar	31	25 - 57	7 - 22	63 - 110
CPP-All	29	20 - 44	6 - 19	55 - 92
CPP-All +EE+Solar	33	23 - 52	6 - 20	62 - 105
Beyond_CPP_Existing	33	23 - 52	7 - 21	63 - 106
Beyond_CPP_All	33	25 - 57	8 - 26	66 - 116

Table 4.4. Benefits per Ton CO_2 Avoided in 2030

Monetized benefits in 2030 (\$2013)	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxide	Total
Reference Case+EE +Solar	52	16 - 36	7 - 23	75 - 110
CPP-Existing	52	44 - 99	12 - 39	108 - 190
CPP-Existing+EE +Solar	52	42 - 95	11 - 36	105 - 183
CPP-All	52	34 - 78	10 - 33	97 - 163
CPP-All +EE+Solar	52	36 - 81	10 - 32	97 - 164
Beyond_CPP_Existing	52	33 - 76	10 - 32	95 - 160
Beyond_CPP_All	52	35 - 80	10 - 32	97 - 164

Note: Benefits per ton (in \$2013) = \$51.7 for CO_2, \$45,584-103,600 for SO_2 and \$12,121-38,332 for NOx. The benefits are based on national numbers using a discount rate of 3%, except for ozone which has benefits only in the analysis year and therefore is not subjected to discounting. NOx benefits includes its role as a precursor for both PM2.5 and ozone. Sources: EPA (2015, Tables 4-2 on p. 4-12 and Table 4-3 on p. 4-27); Graf2000 Table 117, Row 3,4,8.

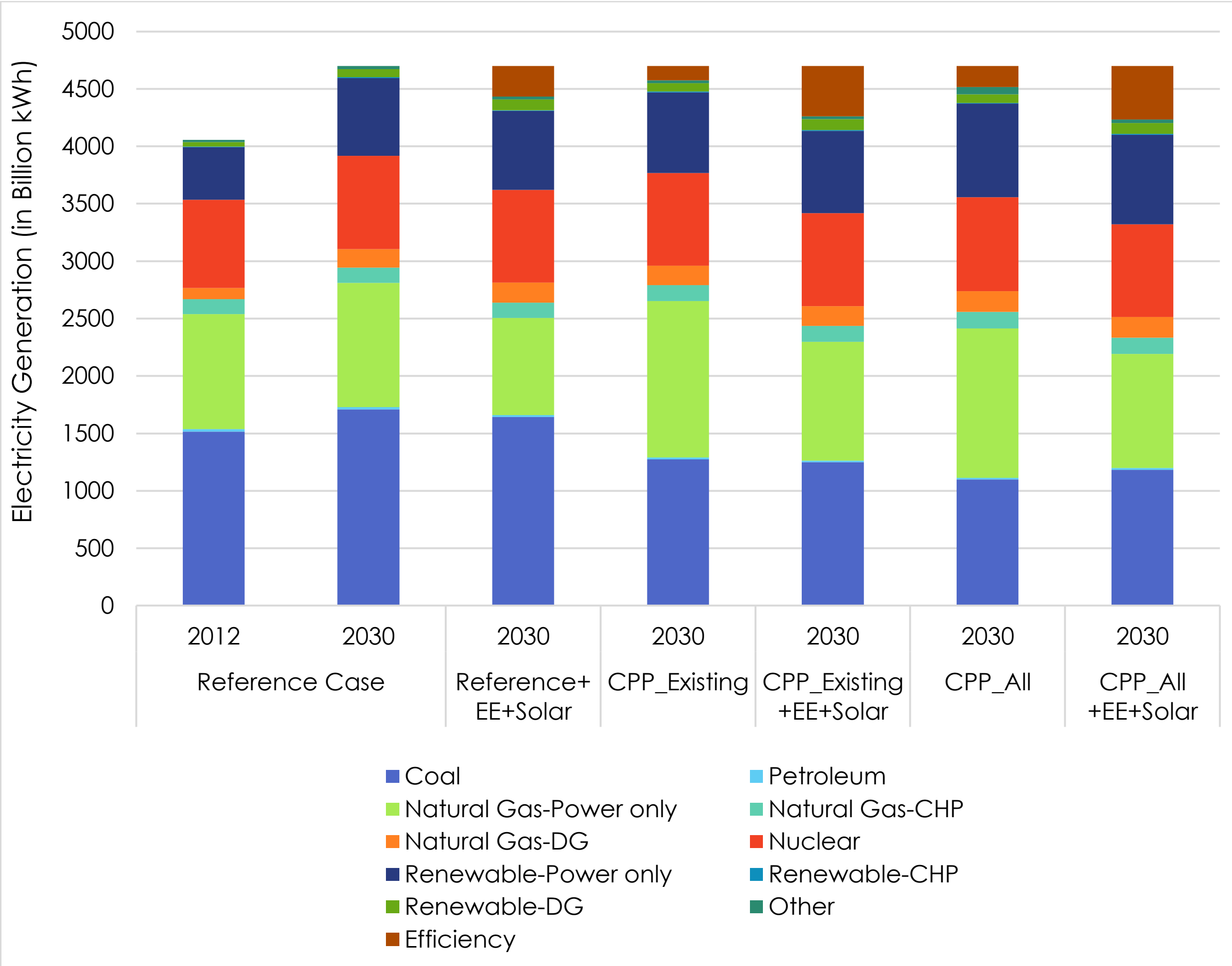
4.2 Impact of CPP on the Electricity Generation Portfolio

In the absence of new policies, electricity consumption in the U.S. is forecast to grow steadily through 2040, at an average annual rate of 0.8%, which is greater than the rate of growth of CO_2 emissions from the electric power sector (0.2%), similar to the growth rate of the U.S. population (0.7%), and much less than the growth rate of the nation's gross domestic product (2.4%) (EIA, 2015a). Specifically, between 2012 and 2030, total net electricity generation is expected to increase by 16% – from 4,055 to 4,698 billion kWh (Figure 4.4). In 2012, 4% of this electricity generation occurs in the end-use sector, growing to 6% in 2030. The growth of DG comes from the 70% growth of natural gas-fueled combined heat and power (CHP) mainly installed in industrial and commercial facilities, and the 81% growth of renewables-based distributed generation. A comparable amount comes from utility-owned CHP in 2012, but it grows negligibly over the following two decades in the electric power sector. Natural gas power generation grows rapidly in the Reference case forecast, but coal, renewables, and energy efficiency also increase across all sectors.

By introducing policies that promote energy efficiency and solar in the absence of the Clean Power Plan, natural gas and coal grow more slowly than in the Reference Case. The growth of natural gas in particular, is curtailed in the electric power sector, while natural gas for distributed generation grows slightly more than in the Reference case. At the same time, renewables grow more than in the Reference case, and energy efficiency expands significantly.

In contrast, all of the CPP compliance scenarios are associated with significant declines in coal-powered generation. Natural gas experiences strong growth in generation in "CPP-Existing" and "CPP-All" when the "EE+Solar" features are not included, especially in "CPP-Existing" when natural gas generates 1,670 billion kWh of electricity in 2030. Renewables grow by 3 billion kWh by utility-owned CHP, 33 billion kWh by end-use sectors, and 245 billion kWh by utilities, and energy efficiency enables 124 billion kWh lower overall electricity consumption, compared to 2012 in the Reference case (Figure 4.4). When "EE+Solar" is added, natural gas grows much more slowly, reaching approximately 1,350 billion kWh in 2030. However, the NG growth in end-use sectors, mainly from CHP generation, is even greater with EE+Solar, while natural gas in electric power sector grows much slower. Renewables and efficiency make up the difference across all of the scenarios. In the CPP scenarios, CHP and DG fueled by natural gas or renewable resources could provide important compliance options to effectively lower resource demands and fuel costs, and results in reduced CO_2 emissions. Nuclear generation would experience little change through 2030, but it would increase by about 1-5% between 2035 and 2040.

Figure 4.4. Impact of CPP Compliance Scenarios on the U.S. Fuel Mix



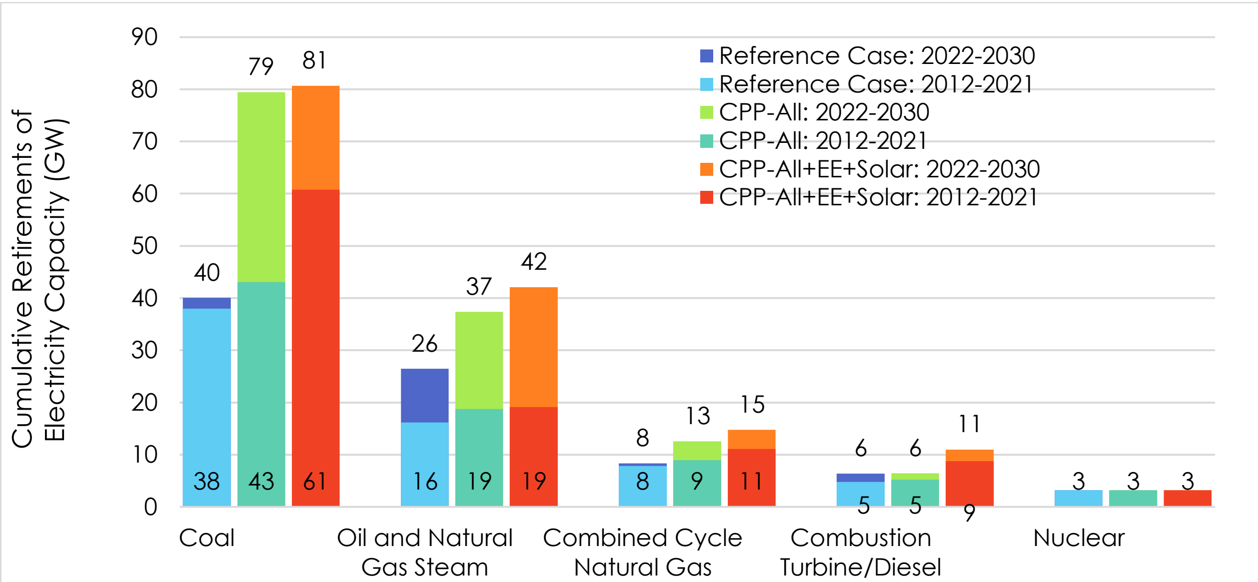
Source: Graf2000 Table 8, Rows 6-20.

One way to assess the magnitude of the impact of the CPP on the nation's electricity fuel mix is to examine the trajectory of generation capacity that would be retired under each of the compliance scenarios. Figure 4.5 shows that even in the absence of new regulations, the electricity sector is being rapidly transformed. In particular, a great deal of generating capacity is expected to be retired in the 2012-2021 timeframe. Indeed, much of this retirement activity has occurred already or is underway. The availability of abundant and affordable natural gas in the U.S., regulatory requirements, public pressure, and sluggish demand growth are all contributing to a spate of coal plant closures that have occurred in recent years and that are planned for the next decade. The environmental regulations proposed and enacted by EPA have reshaped the utility industry. The first federal regulation of mercury, Mercury and Air Toxics Standards (MATS) finalized in December 2011 and published in February 2012,[14] is causing some utilities to shut down coal- and oil-fired power plants that would have been out of compliance.

[14] *Environmental Protection Agency, http://www.epa.gov/mats/*

Similarly, EPA's Cross-State Air Pollution Rule (CSAPR) targeting SO2 and NOx emissions in the eastern U.S. was implemented in 2015,[15] putting further regulatory pressure on utilities.

Figure 4.5. Generating Capacity Retirements (in GW)



Source: Graf2000 Table 9, Rows 47 – 51

As a result of these numerous market and regulatory shifts, approximately 11 GW of coal were retired in 2015, along with nearly 2 GW of natural gas.[16] Between 2012 and 2021, the EIA (2015a) forecasts that 38 GW of coal, 29 GW of natural gas, oil, and diesel generation, and 3 GW of nuclear generation will be retired. In the Reference case, the pace of retirements subsides considerably over the subsequent decade. An additional 2 GW of coal, an additional 11 GW of natural gas, oil, and diesel generation, and no additional nuclear generation are forecast to be retired between 2022 and 2030 (Figure 4.5). Thus, in the first period, retirements total 70 GW and in the second period, retirements total 13 GW for a total of 81 GW, and approximately 50% of the total retired capacity is coal.[17]

In the CPP compliance scenarios modeled here, the pace of power plant retirements accelerates. In the scenario where all affected units are constrained to meet regional

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[15] *http://www3.epa.gov/crossstaterule/*

[16] *https://www.eia.gov/todayinenergy/detail.cfm?id=24152*

[17] Over the next five years (between 2016 and 2020), nearly 85 GW of summer capacity is planned to be retired — about 7% of today's capacity. Most of this retired capacity (63 GW) comes from the planned retirement of coal plants. The next largest planned retirement comes from natural gas steam turbines, at 13 GW. The magnitude of these planned retirements exceeds the pace of retirement that has occurred over the past six years (from 2010 through 2015), when 70.7 GW of summer capacity was retired. It also exceeds the pace of retirement in our Reference case (Data sources: U.S. Energy Information Administration, Preliminary Monthly Electric Generator Inventory, February 26, 2016. http://www.eia.gov/electricity/data/eia860m/. Accessed in March 13, 2016.)

CPP goals, 79 GW of coal, gas, oil, diesel, and nuclear retire in the 2012-2021 period, and an additional 59 GW retire in the 2022-2030 compliance period for a total of 138 GW. Total retirements increase to 103 GW in the 2012-2021 period when the enhanced EE+solar policies are added. In the second period, retirements total 49 GW, for a total of 152 GW. Thus, the CPP scenarios nearly double plant retirements in the compliance period, compared with the Reference case. This represents 15% of the electric power sector capacity in 2012. The composition of these retirements is similar to those in the Reference case – approximately 50% of the total capacity that is retired comes from coal.

The impact of the CPP on capacity retirements, new construction, and the dispatch of power across types of plants varies by region and across the compliance scenarios. More details on the impacts of alternative compliance pathways on the role of specific fuels are given in the following sub-sections.

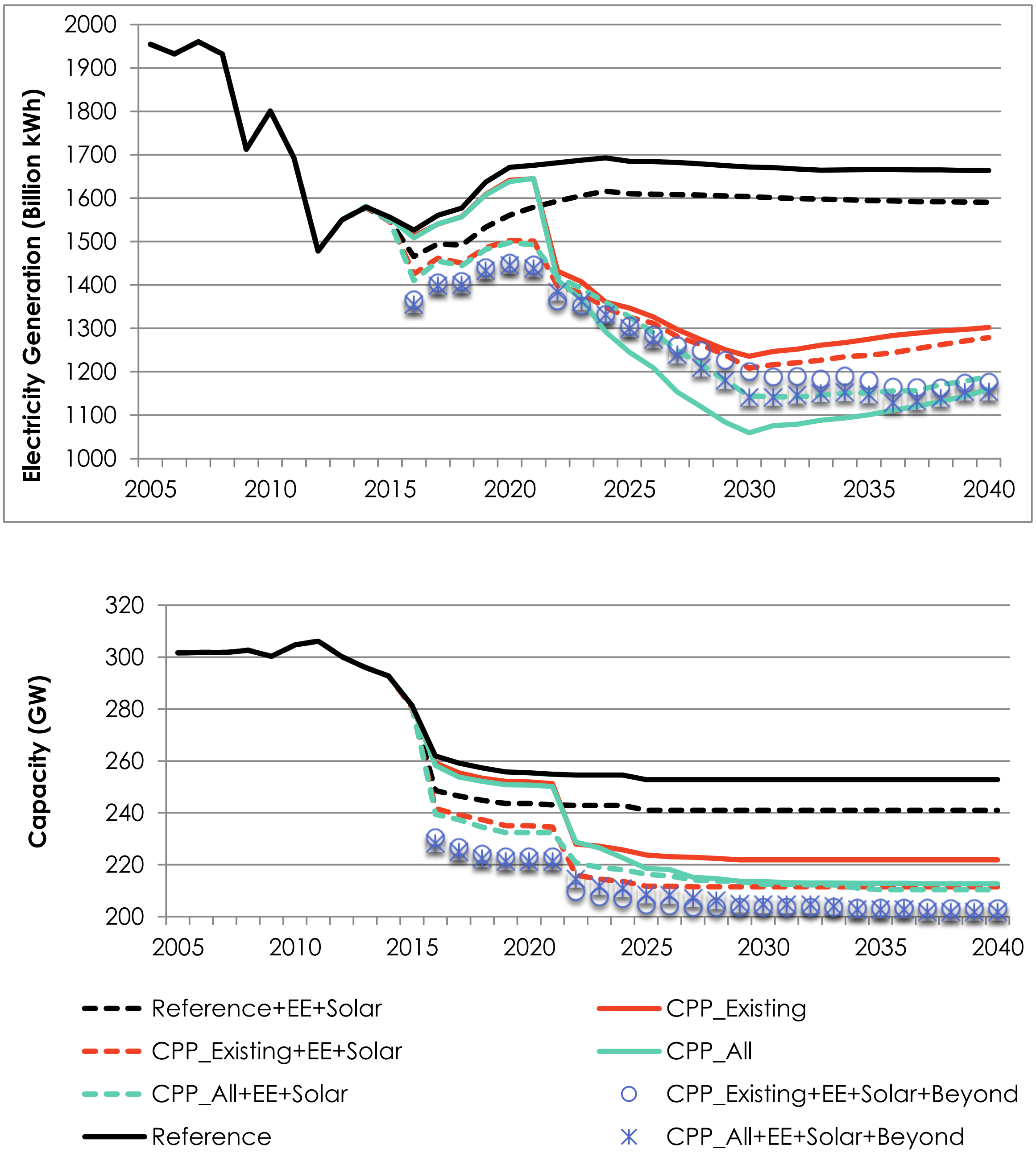
4.2.1 Coal-fired generation

Under the CPP scenarios, coal-fired power loses a large portion of its share in the U.S. portfolio of electricity supply. Generation and capacity for coal-fired power both decrease, driving much of the CO_2 emissions reductions in the compliance scenarios.

Figure 4.6 suggests that generation from coal would decrease relative to the Reference scenario when energy efficiency and solar are deployed more aggressively. The capacity of coal drops by nearly 5% with the 7% reduction of energy consumption in the Reference+EE+Solar scenario.

In all four compliance scenarios, coal generation decreases much more than with efficiency and solar alone, particularly in the first decade of the CPP compliance period. Coal generation rebounds by about 500 billion kWh between 2030 and 2040, and coal capacity plateaus in this decade after dropping sharply between 2015 and 2030.

Figure 4.6. Generation and Capacity of Coal



Source: Graf2000 Table 8, Row 6; Table 9, Row 4

Coal prices also decrease relative to the Reference case in all four compliance scenarios. The decline in coal prices reflects the reduced demand for coal as coal-fired units are retired and the U.S. electricity portfolio is shifted to reduce CO_2 emissions from the electric power sector.

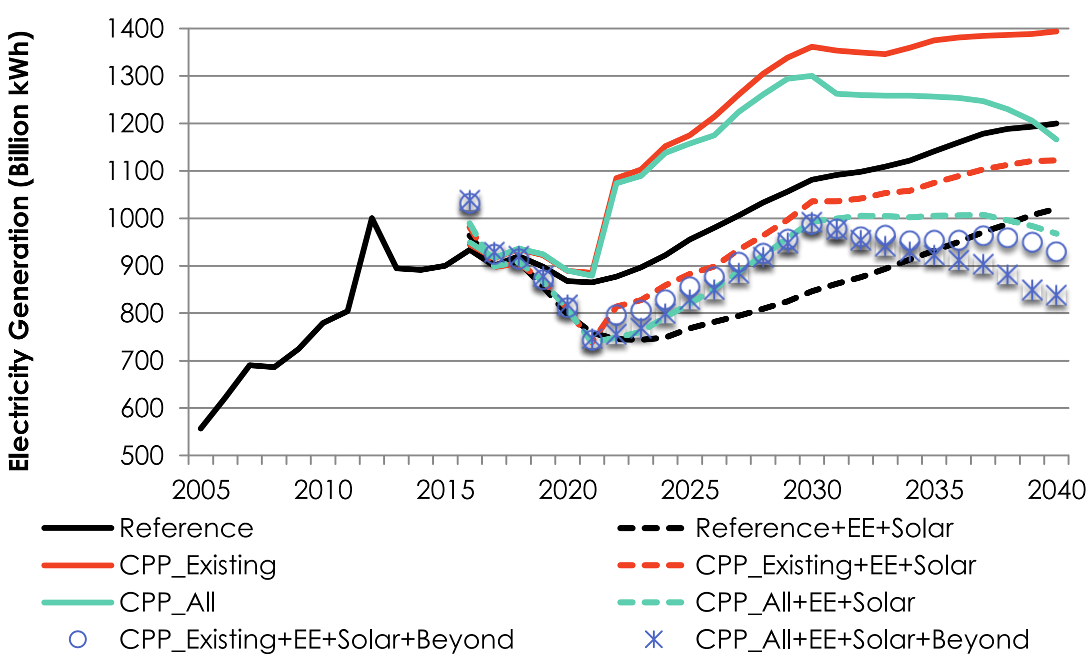
4.2.2 Deployment of natural gas

EIA's Reference case forecasts that natural gas will generate 1,100 billion kWh of electricity in 2030, rising to 1,200 by 2040, from a base of about 600 in 2005 and 900 in 2012.

When energy-efficiency and solar policies are added to the Reference case, natural gas generation grows more slowly. Indeed, it decreases until the beginning of the compliance period, when natural gas generation turns up and grows to about 900 billion kWh in 2030 and 1,050 in 2040 (Figure 4.7).

Under the CPP compliance strategies, natural gas generation increases more quickly, starting before the compliance period as utilities foresee the need to achieve carbon goals by 2025, and it grows rapidly through the compliance period, meeting an increasing portion of U.S. electricity demand. Generation from natural gas units, the capacity of natural gas units, and natural gas prices to the power sector all increase. All four compliance scenarios strongly portray the role of natural gas combined cycle units taking the place of coal-fired steam units as base load generators.

Figure 4.7. Electricity Generation from Natural Gas



Source: Graf2000 Table 8, Row 8

Figure 4.7 shows the generation from natural gas increasing relative to the Reference scenario in the compliance scenarios. Total natural-gas-fired generation largely represents the contributions of natural gas combined cycle units rather than natural gas single-cycle units, as the latter generally have low capacity factors. The demand for low-carbon electricity created by the Clean Power Plan increases the demand for natural gas as an abundant and low-cost source of low-carbon electricity.

While coal plants typically have a lifetime of 30-60 years, natural gas plants typically do not operate for more than 45 years (Tidball, et al., 2010). During the first decade of the twenty-first century, nearly two-thirds of retired generation was natural gas. The vast majority of these retirements were steam turbines that were at the end of their life cycles and inefficient.

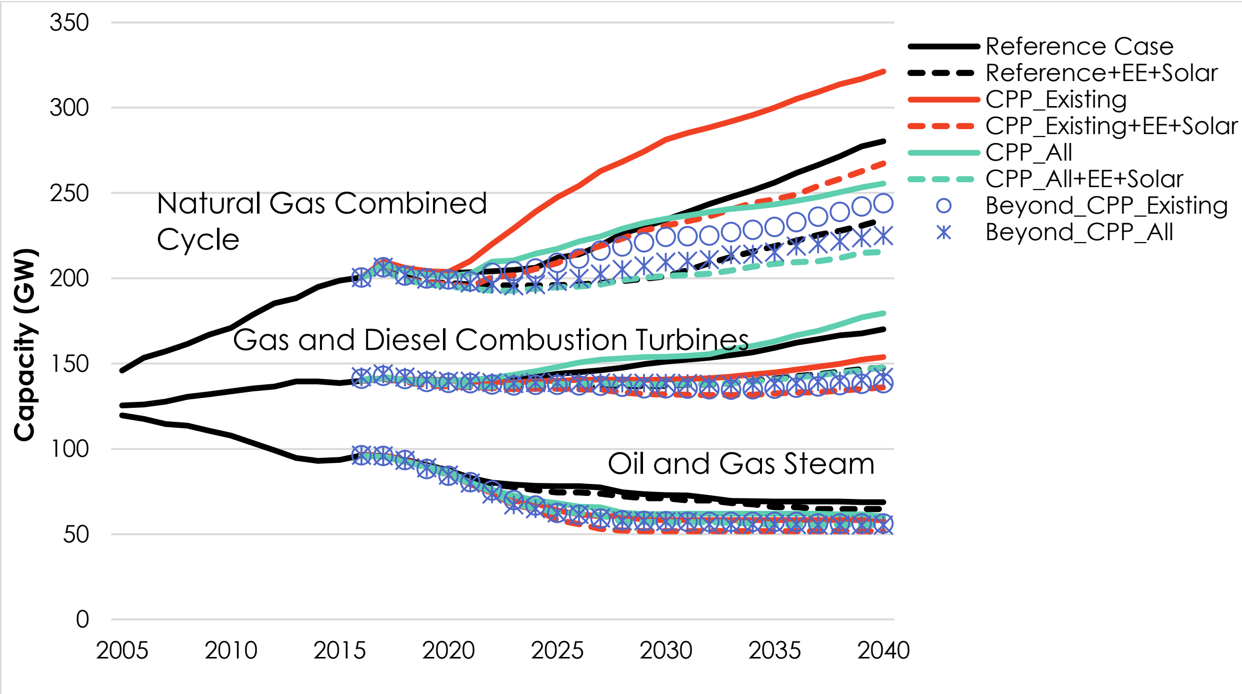
Just 18% of retired generation in the 2000-2010 decade were gas turbines, and most of these were combustion turbines (CTs), which are based on jet airplane engine designs. Air is first compressed by the turbine and fed into the combustion chamber. Methane is then injected into the combustion chamber and burned to produce a high temperature and pressure gas stream. This gas stream is then expanded through aerofoils that spin a turbine to produce electricity. This single cycle is relatively inefficient, but it enables CTs to be ramped up quickly; therefore, they are used principally as peaking resources.

Natural gas combined cycle (CC) generators operate similarly, except that hot exhaust gas from the gas turbine is used to boil water and make steam that powers a secondary steam turbine. They are more efficient than CTs because they re-use waste heat. However, CCs take longer to reach their efficiencies due to the time it takes to make steam. Like CTs, they are able to ramp up and down quickly and so are preferred for intermediate load applications. As a result, less than 10% of retired natural gas plants in recent years have been combined-cycle.[18]

Looking ahead, Figure 4.9 shows the capacity from different types of natural gas generation in the compliance scenarios relative to the Reference scenario, from 2005 to 2040. Natural gas combined cycle units do not phase in as rapidly as coal-fired units are retired. To compensate for coal retirements, the electric power system deploys renewable resources and energy efficiency as well as natural gas; the strain on the rapid construction of natural gas infrastructure is therefore less immediate.

[18] http://www.eia.gov/todayinenergy/detail.cfm?id=4290

Figure 4.8. Capacity of Natural Gas (and Oil and Diesel) Generators (in GW)



Source: Graf2000 Table 9, Rows 5-7.

The compliance scenarios generally favor combined cycle natural gas technologies (particularly in the absence of EE+Solar), since these are the most efficient and carbon-lean of the natural gas generation systems with the exception of natural gas cogeneration. In contrast, the compliance scenarios curb the growth of combustion turbines and diesel generators considerably since they are generally quite inefficient. In addition, the compliance scenarios accelerate the decline of oil and natural gas steam generation.

- Oil and natural gas steam units had a total capacity of 99 GW in 2012, but this drops to 73 GW in the Reference case by 2030 and to 52 in the "CPP-Existing+EE+Solar" scenario in the same year.
- Similarly, combustion turbine and diesel capacity grows to 136 GW in 2012, but it increases to only 151 GW in the Reference case in 2030, while it drops to 132 GW in the "CCP-Existing+EE+Solar" scenario.
- Finally, combined cycle natural gas units grow from 185 GW of capacity in 2012 to 234 GW in the Reference case in 2030. Without the "EE+solar" modifications, the CPP compliance scenarios boost this technology's capacity above where it would be in the Reference case, reaching 231 GW of capacity in 2030 and 267 GW in 2040 under the CPP-Existing+EE+Solar scenario. In general, the rush to natural gas generation is tempered by the addition of the "EE+Solar" modifications.

Natural gas prices in the CPP scenarios rise relative to the Reference case in the early portion of the forecast; however, they fall relative to prices in the Reference scenario during the later portion of the forecast. By 2030, natural gas supply catches up with the near-term surge in demand, resulting in a price reduction.

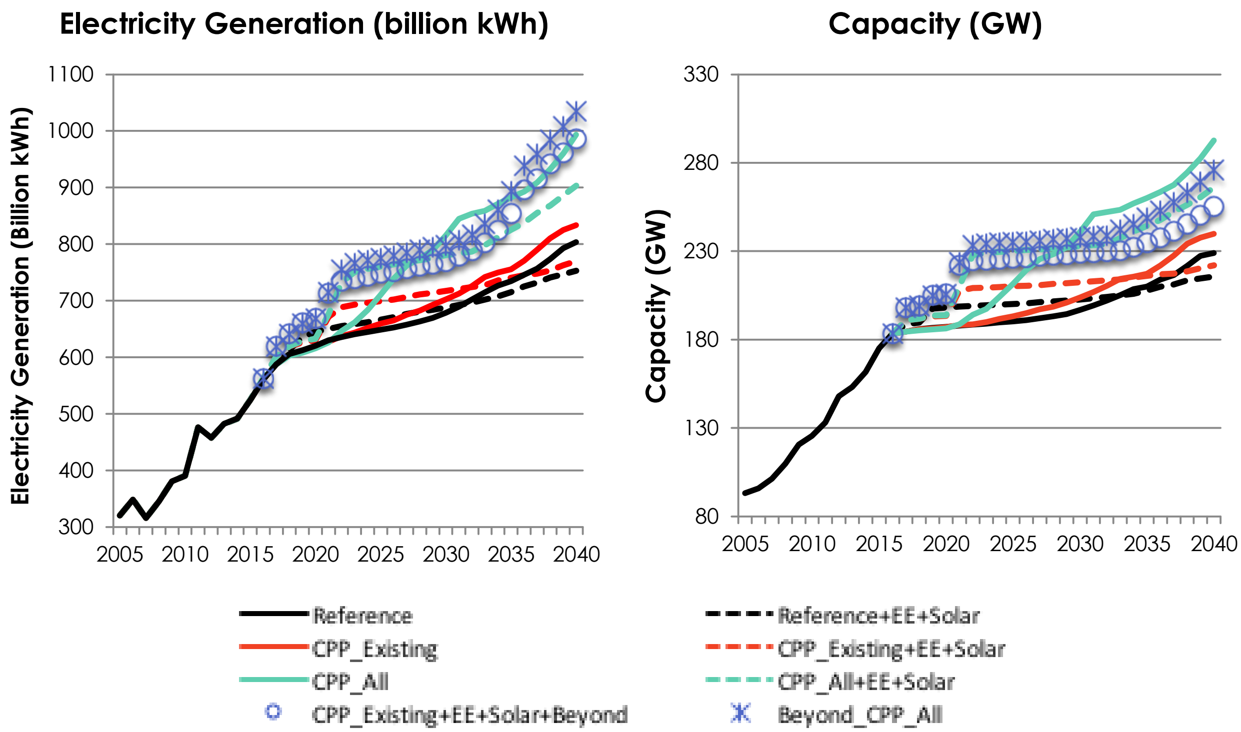
4.2.3 Deployment of renewable energy

Under the Clean Power Plan, incremental renewable energy capacity can help to meet the mass-based goals by providing zero-emission sources of energy. Incremental renewable energy capacity is defined as units that first become operational after 2012. Both utility-scale and distributed renewable energy capacity can contribute to meeting the mass-based goals without any special accounting, unlike the case of the rate-based goals where they must be explicitly added to the denominator in order to reduce the rate of CO_2 emissions/MWh.

In EIA's Reference case, utility-scale renewables meet an increasing share of U.S. electricity demand. From a base of about 460 billion kWh in 2012, their generation grows to about 690 billion kWh in 2030 and 800 in 2040. When energy-efficiency and solar policies are superimposed on the Reference case, the growth of utility-scale renewables is amplified by 9 billion kWh in 2030, but it drops to about 50 billion kWh relative to the Reference case in 2040 (Figure 4.9).

In the two compliance scenarios that do not include energy-efficiency and solar policies, generation from renewable sources increases relative to the Reference case – adding about 100 billion kWh in 2030 and 200 billion kWh in 2040 in the "CPP-All" scenario. The increase in renewables is de minimis in 2030 and 2040 in the "CPP-Existing" scenario, partly due to "leakage". However, when energy-efficiency and solar policies are added to the CPP compliance scenarios, the growth of utility-scale renewable electricity slows relative to the Reference case. When tracked in terms of capacity, similar trends are seen. Thus, our modeling finds that the modest growth in deployment of utility-scale renewables that would occur by applying the Clean Power Plan constraints, are eliminated by the presence of load reductions from energy efficiency.

Figure 4.9. Generation and Capacity of Utility-Scale Renewables (including Hydro) (Billion KWh)



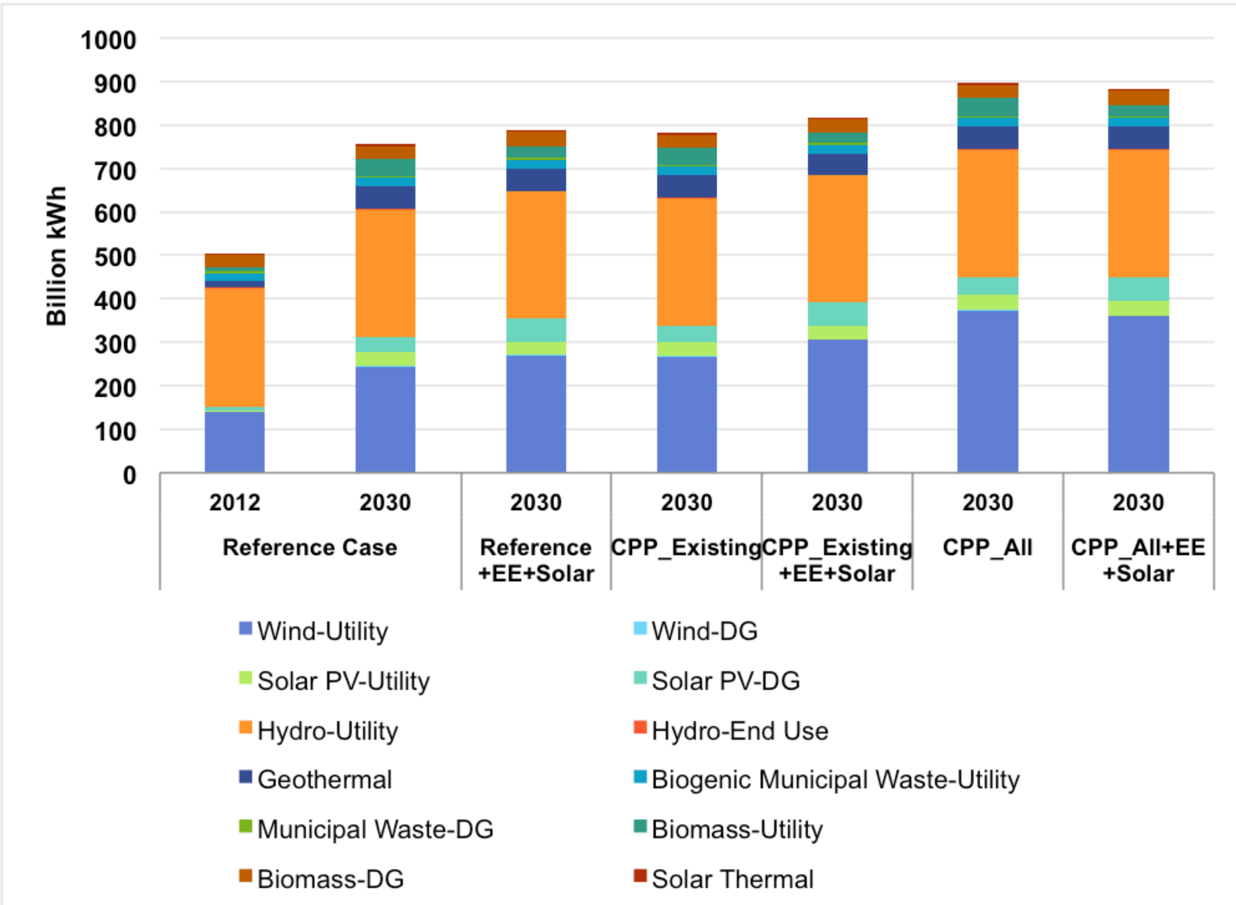
Source: Graf2000 Table 8, Row 11 and Table 9, Row 11.

Figure 4.10 shows the trajectory of individual utility-scale renewable resources: wind, solar PV and thermal, geothermal, biomass and municipal waste, and hydropower. In addition, the chart displays the individual distributed generation (DG) renewable resources: distributed wind, residential and commercial solar PV, distributed biomass, and distributed municipal waste. In the Reference case, nearly all of the renewable sources of electricity increase between 2012 and 2030. Each of the compliance scenarios would increase renewable resources in 2030, relative to the Reference case. However, the response to the scenarios is distinct across renewable resources and between utility-scale and distributed resources.

Hydropower generation is largely unaffected by the CPP scenarios. It increases slightly between 2012 and 2030 in the Reference case, but its fate is largely unaffected by any the CPP scenarios. Distributed hydropower is not modeled in GT-NEMS.

Utility-scale and distributed wind, on the other hand, increase significantly in the Reference case. In total, it grows from 140 Billion kWh in 2012 (when it is 85% utility-scale) to 240 Billion in 2030 (when it is 75% utility-scale). By 2030, wind rivals the role of hydropower in the U.S. electric grid, and by 2040, GT-NEMS forecasts that wind will exceed hydropower. With the addition of energy-efficiency and solar policies to the Reference case, utility-scale wind increases, and it grows further when the CPP constraints are added. Distributed wind, on the other hand, is largely unaffected by the CPP scenarios.

Figure 4.10. Mix of Renewable Generation in the U.S.



In the Reference case, both utility-scale and distributed solar PV generation grow significantly from 2012 to 2030. They both increase by about 550%, from 10 Billion kWh in 2012 to about 70 Billion kWh in total in 2030. When the energy-efficiency and solar policies are added to the Reference case, utility-scale solar is largely unchanged. The deployment of distributed solar, on the other hand, approximately doubles beyond the Reference case. While demand shrinks with the push on energy efficiency, the build out of distributed solar is accelerated by the assumption of reduced solar system costs and the addition of Investment Tax Credits. The addition of the CPP constraints, on its own, does not expand distributed solar.

Electricity from municipal solid waste does not grow under any of the scenarios shown in

Figure 4.10. While utility-scale biomass grows between 2012 and 2030 in the Reference case, its growth is limited when the EE+Solar features are added. While biomass-powered resources are allowed to generate emissions reduction credits under the rate-based goals, they do not receive special treatment under the mass based goals. As such, the CO_2 emissions from biopower resources count against the allowance budgets for each region complying with the Clean Power Plan. Contrary to the contribution of biomass resources toward CO_2 emission reductions in the Clean Power Plan, biomass resources are viewed by the IPCC and other prominent research entities as essential resources for combating climate change. The ability to capture CO_2 existing in the atmosphere is what makes biomass resources valuable for climate change mitigation in the eyes of many. In the U.S. electricity sector, this opportunity appears to be quite limited.

Studies to date have been inconsistent in characterizing the future role of renewables under carbon emission constraints. Some conclude that the Clean Power Plan will do little to drive growth in renewable resources (Ross, Hoppock and Murray, 2015). Others indicate that the CPP would result in only modest increases in renewable energy, such as the modeling by M.J. Bradley (2016), which projects that mass-based CPP goals would produce at most 10 GW of additional renewable capacity in 2030. Our results show the opportunity for more significant levels of growth.

4.2.4 Deployment of nuclear energy

Sluggish demand growth and the low cost of natural gas are putting nuclear units at risk. While nuclear plants are compliant with MATS, CASPR, and the CPP, they are impacted by Nuclear Regulatory Commission (NRC) requirements, for instance the enhanced measures that became standard following the Fukushima-Daiichi incident. Some nuclear units are also small, operating as single reactors on a plant site with no opportunities to benefit from economies of scale, and they are aging. SNL Energy (2015) has identified 12 "at risk" nuclear units that could retire, amounting to a loss of approximately 10 GW of capacity operating at capacity factors of 90% or higher. These are in addition to the four nuclear units that have shut down in 2014-15, and the two units that were announced to be retired in the near future: Entergy's Pilgrim nuclear plant in Massachusetts, and Fitzpatrick, in New York State. Where markets are competitive, it is harder for nuclear-power operators to make money, and too risky to build new nuclear plants.

New nuclear units are able to qualify for emission reduction credits in the Clean Power Plan, while existing units cannot. As a result, existing nuclear units can find it difficult to compete against low-cost natural gas plants in open markets. At the same time, five new nuclear reactors are under construction. The NRC issued an operational license in October 2015 for the Watts Bar 2 reactor in Tennessee; when it comes online, it will become the first new unit to operate since the 1990s. Four additional units are under construction (two in Georgia and two in South Carolina) and more await licensing.

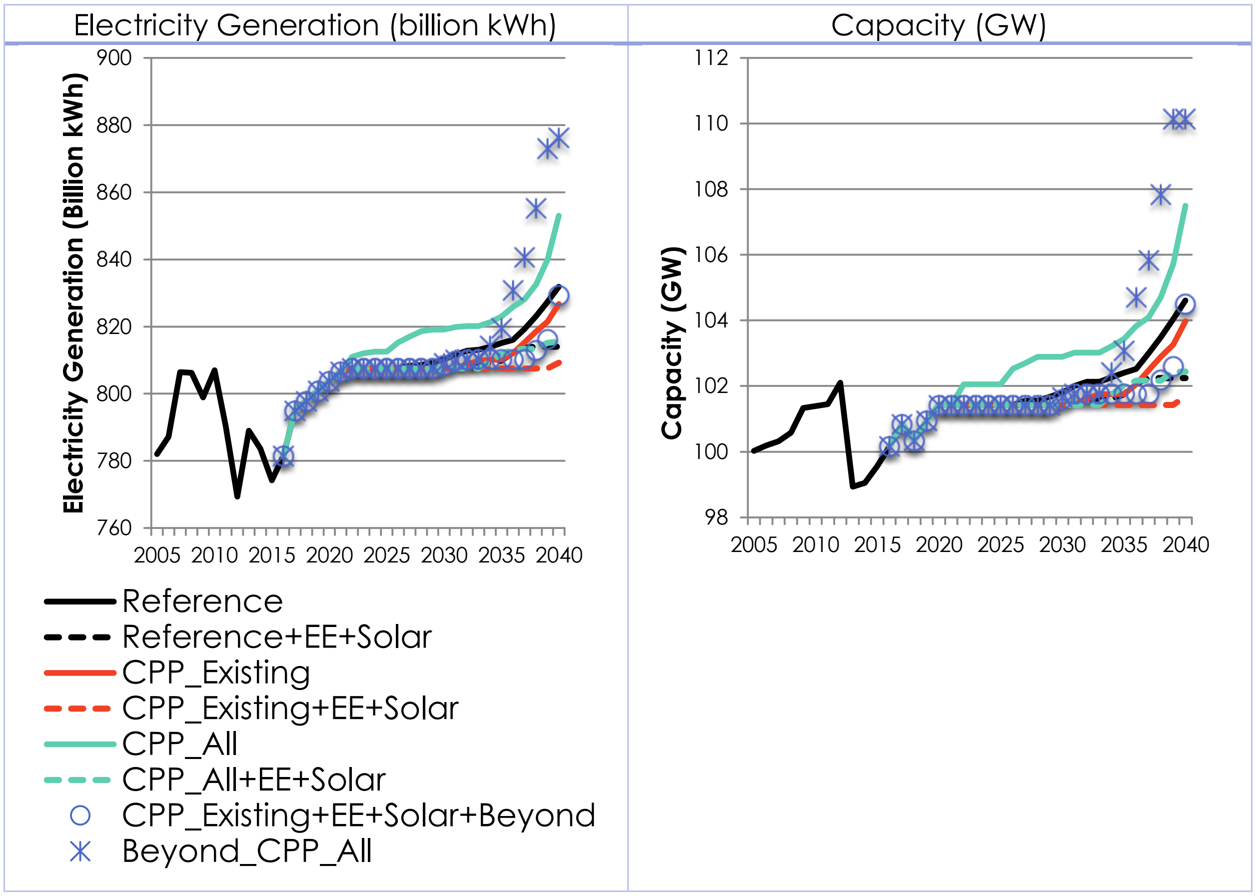
Under the Clean Power Plan, incremental nuclear energy capacity (post-2012) can help to meet the mass-based targets by providing a zero-emission source of energy. As a base load resource, nuclear power offers a zero-emitting alternative to the coal-fired resources that are expected to retire under the Clean Power Plan. They can also contribute to achieving rate-based goals, by adding zero-carbon generation to the denominator of the rate calculation.

In the 2015 Reference case, nuclear energy is forecast to grow by only 1% between 2012 and 2030. Three GW of nuclear capacity are expected to retire in the 2012-2021 timeframe (Figure 4.5), some are uprated, and five new units are built. Nuclear generation is forecast to grow by about 3% by 2040 in the Reference case.

During the CPP compliance period, nuclear generation and capacity are expected to return to their 2012 levels of almost 810 billion kWh and about 101.5 GW, which are close to the nuclear industry's historic peaks. As in the Reference case, nuclear generation is forecast to grow by about 3% by 2040.

Nationwide, nuclear power does not displace a significant amount of fossil-fueled generation under the compliance scenarios investigated here. Figure 4.11 shows that the "CPP-Existing" compliance scenario, without the inclusion of enhance energy-efficiency and solar policies, tracks the Reference case forecast. The "CPP-All" strategy, on the other hand, causes nuclear capacity and generation to grow beginning in 2025. This is inconsistent with other studies that have found that the Clean Power Plan will do little to bring new nuclear generation online (see Hopkins, 2015, which reviews a number of evaluations of the proposed CPP). As is the case with utility-scale renewables, our modeling reveals that the load reductions from energy efficiency produce a reduced deployment of nuclear resources relative to the Reference case.

Figure 4.11. Generation and Capacity of Nuclear



Source: Graf2000 Table 8, Row 9; Table 9, Row 8

4.2.5 Energy-efficiency savings

EIA forecasts that electric power generation will grow at an annual rate of 0.8% between 2012 and 2030 (EIA, 2015a, Table A8). Were this growth rate to materialize, the electric power sector in 2030 would need to generate 16% more power in 2030 than it generated in 2012.

All of the compliance scenarios examined in this paper produce reductions in electricity use and associated CO_2 emissions relative to the EIA forecast.

- When the "EE+Solar" features are added to the Reference case, electricity consumption in 2030 in the U.S. declines by 279 billion KWh, or 7%.
- The CPP compliance scenarios on their own (that is, "CPP-Existing" and "CPP-All") result in a 3-4% reduction in electricity consumption in 2030, relative to the Reference case.

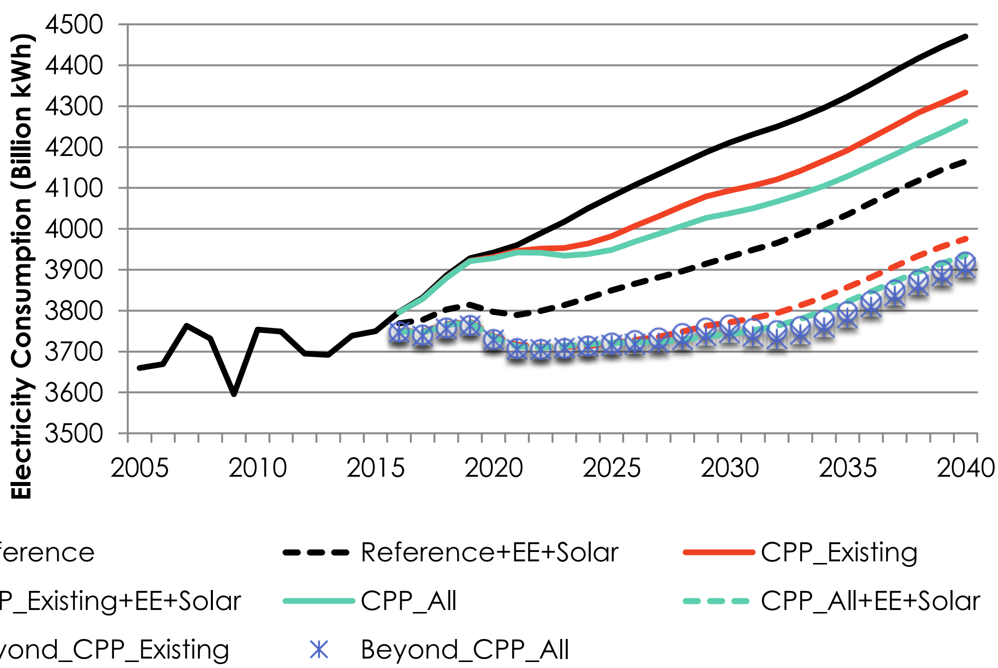
- When the CPP constraints are combined with the EE+Solar features, the result is additive – producing reductions of 440-469 billion kWh (or 10-11%) in 2030.

As shown in Figure 4.12, electricity consumption stays flat in these combined cases from 2015 until 2030, when a notable uptick in consumption begins that continues through the final decade of our planning horizon.

EIA is using a new version of NEMS 2015 prepared to complete its own CPP impact analysis. This NEMS version expands energy efficiency by running utility programs where the bulk of the costs are subsidized by utilities and are rate-based. In contrast, we expand building codes and appliance standards and improve residential, commercial, and industrial end-use technologies as the basis for much of our savings, along with selectively lower discount rates and investment tax credits for CHP. (See Table 3.1 for further details.)

The range of 440-469 billion kWh of reduced consumption in 2030 in the compliance scenarios with enhanced energy efficiency and solar is within the range of findings of other studies. Specific comparisons to previous assessments are as follows.

Figure 4.12. Total Electricity Consumption (Billion kWh)



- Our range of 440-469 TWh is less than the energy-efficiency limit of 709 TWh estimated by Lashof and Yeh (2014) in their full EE case (with average efficiency costs of 2.7¢/kWh) and less than the 707 TWh of energy efficiency modeled by Brown et al

(2015) in their clean power pathway report that modeled the proposed CPP using a tax on carbon in the electricity sector.

- It is comparable to the 325 TWh estimated by EPA (Hopkins, 2015), the range of 347-587 TWh by M.J. Bradley & Associates (2016), the 506 TWh estimated by Eldridge et al. (2008) (with average efficiency costs of 7.8¢/kWh), and the 457 TWh (11% decrease) estimated by Wang and Brown (2014) (with an average efficiency cost of 0.5 to 8.1¢/kWh).
- It is greater than the 244 TWh of EE gains estimated by Rhodium (with average efficiency costs of 7.8 ¢/kWh), and greater than the 238 TWh estimated by NERA (with average efficiency costs of 12.5 ¢/kWh). The range is also significantly greater than EIA's CPP report, which shows EE expanding by only 81 TWh by 2030 relative to the Reference case (EIA, 2015b, Table 18).

Households, businesses, and industry all experience an increase in energy efficiency in the CPP compliance scenarios. For example, the "CPP-All+EE+Solar" scenario causes electricity consumption to be reduced by 14% in the residential sector, 10% in the commercial sector, and 9% in the industrial sector. The reduction in the electricity consumption of businesses in the Reference+EE+Solar case is diminimus because it prompts significant fuel switching from natural gas heat to electric rooftop systems that offer more competitive costs to consumers. Recall that the EE+Solar features include higher-efficiency space heating and cooling equipment along with stronger standards for rooftop units, as announced by DOE in December 2015 with implementation beginning in 2018.[19] In the "CPP-All+EE+Solar" scenario, natural gas consumption in the commercial sector declines by 72 trillion Btu (2%).

[19] http://energy.gov/articles/energy-department-announces-largest-energy-efficiency-standard-history

Table 4.5. Impacts on U.S. Electricity Consumption in 2030

	Households		Businesses		Industry		Total	
	Billion kWh	% Change	Billion kWh	% Change	Billion kWh	% Change	Billion kWh	% Change
Reference Case 2012	1375		1327		986		3695	
Reference Case 2030	1490		1524		1185		4211	
Reference+EE+ Solar	1291	-13%	1521	0%	1108	-7%	3932	-7%
CPP-Existing	1448	-3%	1480	-3%	1153	-3%	4093	-3%
CPP-Existing +EE+Solar	1285	-14%	1388	-9%	1086	-8%	3771	-10%
CPP-All	1433	-4%	1458	-4%	1134	-4%	4037	-4%
CPP-All+EE+Solar	1277	-14%	1376	-10%	1077	-9%	3742	-11%
Beyond-CPP-Existing	1284	-14%	1387	-9%	1083	-9%	3765	-11%
Beyond-CPP-All	1279	-14%	1378	-10%	1078	-9%	3746	-11%

**Percent change from Reference Case in 2030. Source: Graf2000 Table 8, Rows 50-52*

Table 4.6. Impact on U.S. Natural Gas Consumption in 2030

	Households		Businesses		Industry		Utility		Total	
	QBtu	% Change	QBtu	% Change	QBtu	% Change	QBtu	% Change	QBtu	% Change
Reference Case 2012	4.25	-	2.97	-	7.39	-	9.31	-	23.96	-
Reference Case 2030	4.52	-	3.42	-	8.66	-	9.09	-	25.85	-
Reference-EE+Solar	4.17	-8%	3.10	-10%	8.23	-5%	7.57	-17%	23.23	-10%
CPP-Existing	4.50	-1%	3.41	0%	8.55	-1%	10.71	18%	27.29	6%
CPP-Existin-+EE+Solar	4.15	-8%	3.03	-11%	8.19	-5%	8.62	-5%	24.16	-7%
CPP-All	4.49	-1%	3.43	0%	8.55	-1%	11.05	22%	27.65	7%
CPP-All+ EE+Solar	4.15	-8%	3.04	-11%	8.19	-5%	8.67	-5%	24.20	-6%
Beyond-CPP-Existing	4.16	-8%	3.04	-11%	8.17	-6%	8.34	-8%	23.87	-8%
Beyond-CPP-All	4.15	-8%	3.04	-11%	8.20	-5%	8.52	-6%	24.07	-7%

**Percent change from Reference Case in 2030. Source: Graf2000 Table 8, Rows 50-52*

5. IMPACT ON BILLS AND RATES

5.1 Electricity Bills across Sectors

In the Reference case, economy-wide electricity bills per capita (across all customer classes) are expected to increase by 10% between 2012 and 2030 as the result of increasing demand for electrical goods and services as well as increased rates caused by rising fuel costs, environmental regulations, and other factors (Table 5.1).[20] When enhanced energy efficiency and solar policies are added to the Reference case, electricity bills per capita in 2030 would remain at their 2012 level because of reduced demand and lower electricity rates.

Table 5.1. Impact of the CPP Compliance Scenarios on U.S. Electricity Bills Per Capita in 2030 (in $2013)*

($2013)	Residential Consumers	Businesses	Industries	Total
Reference Case 2012	527.1	431.9	211.7	1172.7
Reference Case 2030	563.6	469.4	252.6	1289.5
Reference+EE+Solar	489.3	451.0	229.6	1173.7
CPP-Existing	576.2	480.4	264.6	1325.1
CPP-Existing+EE+Solar	494.3	427.5	234.1	1159.7
CPP-All	593.1	497.2	277.0	1371.6
CPP-All+EE+Solar	503.6	438.0	241.8	1187.4
Beyond-CPP-Existing	495.2	428.3	233.7	1161.1
Beyond-CPP-All	500.7	434.7	238.9	1178.3

Source: Graf2000 Table 8, Rows 50-52, and 54; Table 2, Row 152; Table 3, Rows 6, 13, 23, and 54

In the compliance scenarios that simply impose carbon constraints, electricity bills would increase approximately 3% (CPP-Existing) and 7% (CPP-All) more in 2030 compared with the Reference case forecast, rising by about 10%, in total. However, with enhanced energy efficiency and solar, the compliance scenarios generate economy-wide electricity bills per capita that are lower than those forecast for 2030 in the Reference case, saving every person in the U.S. $102 in 2030 (in $2013), with similar savings in earlier and later years, as well. These savings allow residential consumers and businesses to purchase additional goods and services that expand employment and increase

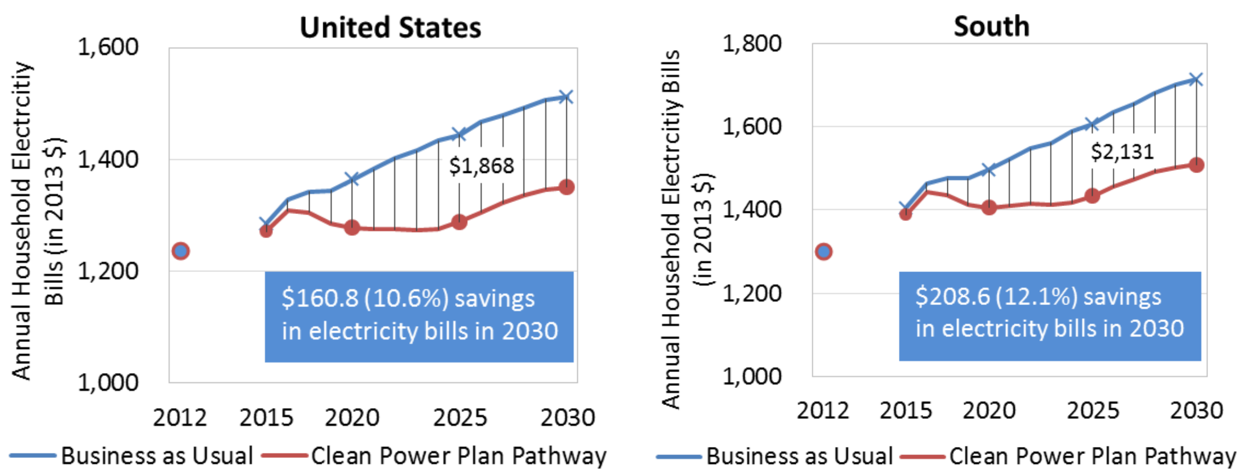
[20] For more information on electricity prices and expenditures by sector at: http://www.eia.gov/state/seds/seds-data-complete.cfm?sid=US#PricesExpenditures

economic activity.

As indicated in Table 5.1, U.S. electricity bills per capita for residential customers would be $564 in the Reference Case in 2030, totaling nearly $180 billion across the 350 million population of the U.S. projected for that year. Per capita electricity bills would be only $504 in the CPP-ALL+EE+Solar scenario in 2030, resulting in $60 in savings per capita and $161 per household in that year (see Figure 5.1). Cumulative savings over the 15 years would be much greater, at $1,868 per household. Across the U.S., households could experience cumulative electricity savings of $248 billion.

Households in the South would save more on their electricity bills than the average U.S. household, if the CPP-ALL+EE+Solar compliance pathway were adopted.

Figure 5.1. Savings in Household Electricity Bills in 2030 (in 2013 cents/kWh)



*All savings are in $2013. Savings are estimated as the difference between the Reference Case forecast and electricity bills from the CPP-ALL+EE+Solar scenario.

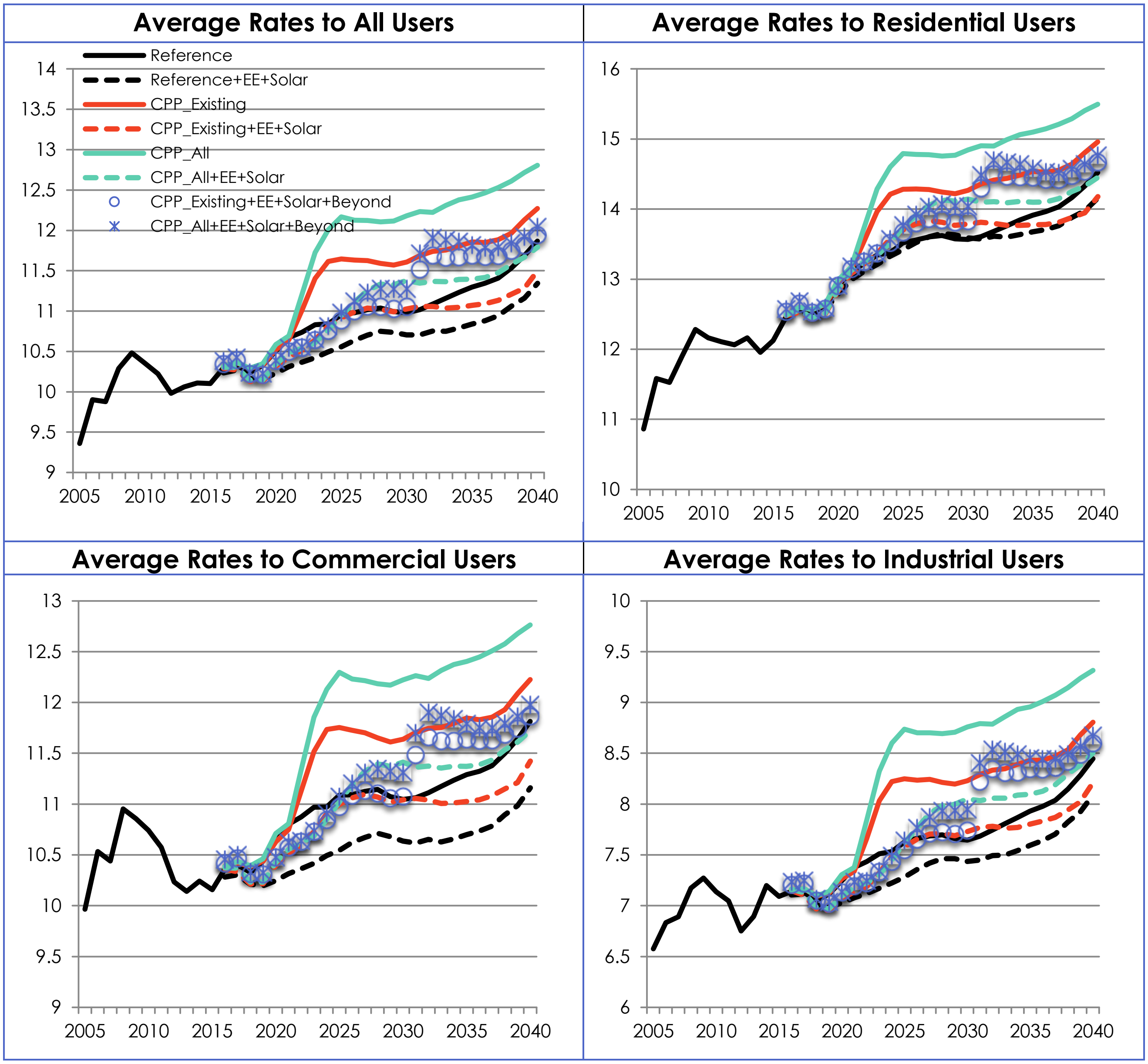
In summary, compliance with the CPP mass-based goals can be achieved while curbing the increase in electricity bills forecast by the Reference case.

5.2 Impacts on Electricity Prices

Electricity rates are expected to rise over the next several decades, according to the Energy Information Administration's Reference case forecast, increasing from 9.84 ¢/kWh to 10.48 ¢/kWh nationwide (

Figure 5.2).

Figure 5.2. Electricity Prices in 2013 cents/kWh



Source: Graf2000 Table 3, Rows 72, 79, 89, and 121
**1 MMBtu = 293.071 kWh*

These prices would be similar or higher in 2030 under all of the compliance scenarios. However, prices in the compliance scenarios that include energy-efficiency and solar policies are only slightly above the 2030 forecast, and they would drop below the Reference case forecast in the 2030-2040 decade. Other studies of CPP compliance options have concluded that retail prices would rise above the business-as-usual forecast, for example by 6.9% to 13% in the CATF study, NERA, and Rhodium studies described in Hopkins (2015). Energy efficiency did not play as strong a role in the compliance pathways examined in these studies. Indeed, some studies have examined compliance outcomes without using energy efficiency to credit CO_2 reductions (Hopkins, 2015). The differences across these various modeling efforts again confirm that marginal compliance costs are likely to be lower with more energy efficiency.

5.3 Investment Costs

In the compliance scenarios with enhanced energy efficiency and solar, additional investment is needed to purchase more energy-efficient equipment, to improve the thermal integrity of buildings, and to upgrade the efficiency of industrial systems. In general, an "efficiency premium" must be paid when purchasing high-efficiency heating and cooling equipment, appliances, lighting, motors, boilers, and other end-use technologies and to upgrade insulation and windows to reduce heating and cooling requirements. These premiums typically vary from 10 to 30% of the cost of equipment, appliances, and building materials (Brown and Wang, 2015). Some of these costs are covered by incentives offered to customers who participate in utility demand-side management programs. The balance of these costs are paid for by the customers themselves – by households, building owners and occupants, and manufacturing enterprises, for example. These investments are timed to occur at the normal end-of-life of the current equipment, so there is no additional premium paid for the early retirement of existing equipment; that is, accelerated stock turnover is not modeled.

Indirect or softer costs, such as the cost of negotiating utility subsidies and investigating energy-efficiency options are difficult to estimate and therefore are excluded from our analysis. We do estimate the administrative costs required to implement the information, financing, and regulatory programs needed to stimulate energy-efficiency upgrades. Adopting the assumptions of Wang and Brown (2014), program administrative costs are estimated to be $0.13 per MMBtu of energy savings.

The financing to enable such investments can come from a variety of sources. Utility demand-side management programs may offer subsidies through on-bill financing, rebates, or other types of programs. Alternatively, funding for these purchases could come from traditional sources such as personal savings, loans from banks, or mortgages that enable homeowners to add energy-efficiency features to new or existing housing as part of their home purchase or refinancing. Subsidies may be available from cities (e.g., with property assessed clean energy programs), states (e.g., with revolving loan funds or qualified energy conservation bond programs), the federal government (e.g., with tax rebates or grants), and energy-service companies may provide energy-saving performance contracts. Financing options for energy efficiency are numerous and diverse (Brown and Wang, 2015).

We estimate the magnitude of investment costs by considering the costs that would be incurred in the year 2030 above and beyond the Reference case in that same year, using two discount rates, 2% and 7% in year 2013 dollars. Most of these costs are associated with electricity energy efficiency upgrades, but some are required to achieve improved end-use efficiency for natural gas and petroleum consuming equipment, particularly in the industrial sector where electro-technologies are not as dominant. Investment costs associated with distributed and utility-scale upgrades are already tallied in the net present value of total resource costs shown in Table 5.3. We focus on one of the compliance cases that has the additional investments in energy efficiency and solar ("CPP-All+EE+Solar").

In 2030, the residential buildings sector requires $9-22 billion of investment in energy-efficiency techologies. The commercial sector requires the smallest incremental investment, based on previous analysis (Brown et al., 2015), however these costs are not yet available in this study. The largest additional incremental investment is required by the industrial sector, ranging from $12-$29 billion. Program administration costs are estimated to be less than 1 billion in 2030, based on previous analysis (Brown et al., 2015). These investment costs are summarized in Table 5.2, and are equal to $50 million, in total, excluding the commercial buildings sector.

Table 5.2 Investment Costs in End-Use Energy Efficiency, in 2030 (in Billion $2013)

(in Billion $2013)	Equipment Expenditures	Administrative Cost	Total*
Households	9-22	0.25	9.3-21.7
Businesses	N/A	N/A	N/A
Industries	12-29	0.28	12.3-29.1

**Investment costs are calculated as the differences between the equipment and program administrative costs required by the Reference Case and between the equipment and program administrative costs required by the CPP-ALL+EE+Solar scenario. Ranges represent the difference between using a 2 and 7% discount rate. Without any discounting, the totals are $30.6 billion for households and $41.6 billion for industries. Source: Offline calculations using various Graf2000 tables and the methodology described in Wang and Brown (2014).*
N/A = Not available

5.4 Total Resource Costs of the Electricity Sector

Electricity prices are a function of the costs that utilities incur in the financing, construction, and operation of their electricity generation, transmission, distribution, and end-use resources. These costs are shown in Table 5.3 in terms of the cumulative net present value (NPV) of the electricity sector's costs. GT-NEMS estimates that in 2030, these total resource costs would be approximately 6% higher in the two CPP compliance scenarios that only cap emissions, compared with the Reference case. In contrast, they would be approximately 3% lower in the two compliance scenarios that also include "EE+Solar" features. GT-NEMS measures these costs in cumulative NPV terms, in 2013$, using a 7% discount rate.

Table 5.3. Cumulative Net Present Value of Total Resource Costs in 2030 (in billions 2013$)*

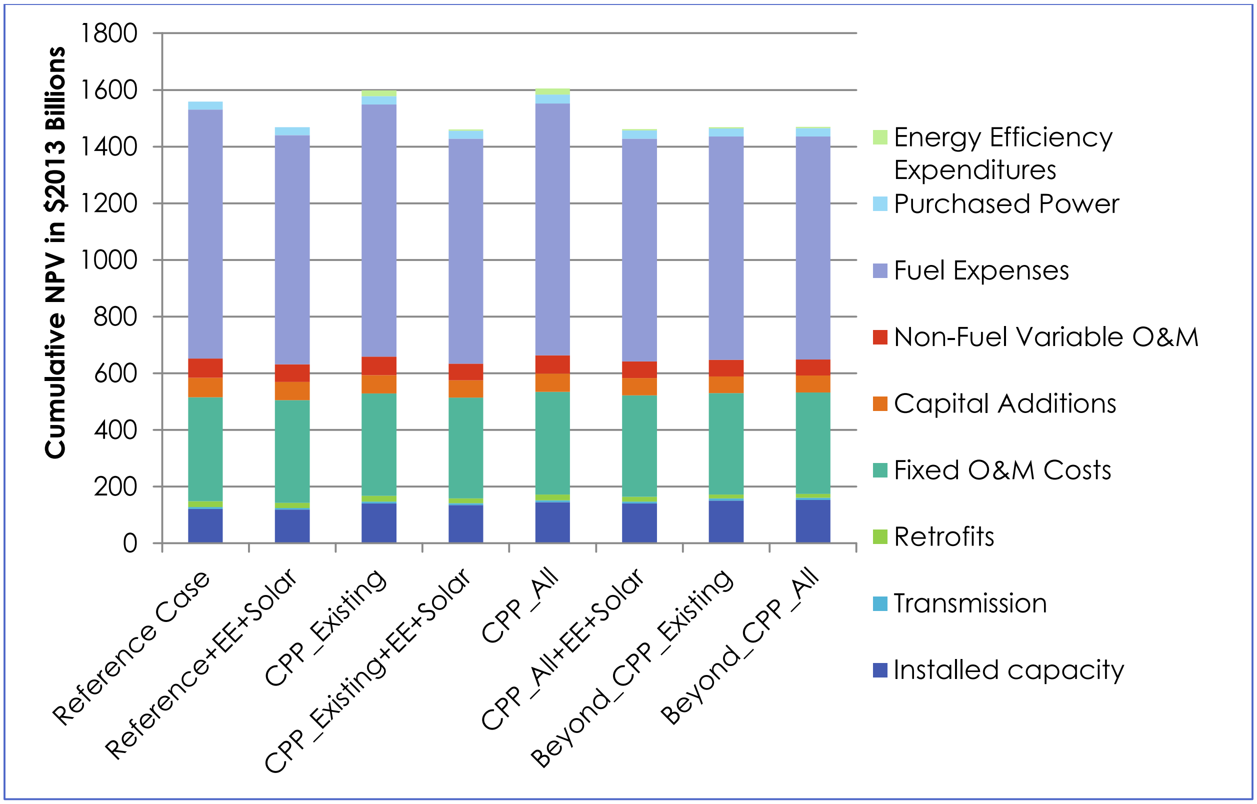
	Installed capacity	Transmission	Retrofits	Fixed O&M Costs	Capital Additions
Reference Case	121.5	6.0	20.4	367.7	68.8
Reference+EE+Solar	118.5	5.8	18.0	362.8	64.0
CPP_Existing	140.1	7.3	19.6	362.2	63.6
CPP_Existing+EE+Solar	134.6	6.8	16.5	356.3	60.6
CPP_All	144.6	7.2	19.6	363.3	63.7
CPP_All+EE+Solar	140.6	7.0	16.3	358.5	60.9
Beyond_CPP_Existing	150.4	7.8	14.1	357.1	59.5
Beyond_CPP_All	152.3	7.8	14.2	358.0	59.6

	Non-Fuel Variable O&M	Fuel Expenses	Purchased Power	Energy Efficiency Costs	Total (% Change from Reference Case)	
Reference Case	67.2	879.2	27.9	0.0	1558.9	--
Reference+EE+Solar	62.0	809.6	27.9	0.0	1468.5	-6.16%
CPP_Existing	65.8	889.9	28.9	21.0	1598.6	2.48%
CPP_Existing+EE+Solar	59.0	794.1	28.3	4.7	1460.9	-6.71%
CPP_All	64.3	889.3	31.9	21.4	1605.3	2.89%
CPP_All+EE+Solar	58.0	787.0	28.7	4.7	1461.7	-6.65%
Beyond_CPP_Existing	57.9	788.9	28.5	4.7	1469.0	-6.12%
Beyond_CPP_All	56.8	787.6	28.9	4.7	1469.8	-6.06%

**Uses a 7% discount rate. Source: Graf2000 Table 116, Rows 43-55.*

Comparing the components of these costs across scenarios shows how costs shift depending on the policy path taken. Compared to the Reference case, the compliance scenarios without additional energy efficiency and solar have higher costs for installed capacity, transmission, fuel expenses, purchased power, and energy-efficiency expenditures. In contrast, the compliance scenarios with additional energy efficiency and solar have relatively small increases for installed capacity costs, and energy efficiency expenditures, and have a large savings ($40 billion) in fuel expenses.

Figure 5.3. Cumulative Net Present Value of Total Resource Costs in 2030 (in billions 2013$)*



**Uses a 7% discount rate. Source: Graf2000 Table 116, Rows 43-55.*

6. ECONOMIC INDICATORS

6.1 Impact on GDP

Between 2012 and 2030, the U.S. population is expected to grow from 315 million to 359 million (14.0%) and real disposable personal income is expected to expand from $10,304 to $15,926 (54.6%) in 2005 dollars. U.S. GDP is expected to grow similarly, from $15.4 trillion (in $2009 chained dollars) in 2012 to $23.9 trillion in 2030, and the value of U.S. industrial shipments are also expected to grow from $30,810 to $44,838 billion in $2009 (Table 6.1).

The national GDP is estimated to grow $61 - $95 billion less in the compliance scenarios in 2030 when EE+Solar features are not included. This is equivalent to less than a week's delay in GDP growth. "Delay" in GDP growth is defined as the number of days in a year required to make up the difference between GDP in the Reference case versus GDP in the CPP compliance scenario. These GDP losses are cut in half when the EE+Solar features are added to the compliance strategies.

The higher equipment investments prompted by the twelve policies would divert the capital that could have been invested in other economic activities. Results from GT-NEMS suggest that this reallocation of capital resources would affect the national GDP, albeit to a small extent. In addition, the policies would reduce energy consumption and production, which also has GDP consequences. As an energy-economic model, GT-NEMS is capable of modeling the macroeconomic impact of any energy policy by incorporating Global Insight's model of the U.S. economy in its Macroeconomic Activity Module (MAM). Both energy demand and supply sides interact with MAM through a Cobb-Douglas production function to calculate the national GDP. However, the IHS Global Insights model assumes the U.S. economy has a 0.07 energy elasticity, which means that a 1% decrease in energy supply decreases potential GDP by 0.07% (EIA, 2012).

Unlike input-output models such as IMPLAN, the reduction in energy expenditures is not recycled back into the economy to reflect re-spending of the energy savings. As a result, NEMS tends to produce estimates of decreased GDP when energy-efficiency investments increase (Laitner, 2009).

Exports are higher (consistent with the greater industrial output) and imports are lower (consistent with the lower domestic energy prices). However, the CPP compliance scenarios have lower GDPs than in the Reference case.

Table 6.1. Components of Real GDP in 2030 (billion in $2009)*

	Consumption	Investment	Government Spending	Exports	Imports	GDP
Reference Case in 2012	10,450	2,436	2,954	1,960	2,413	15,369
Reference Case in 2030	16,275	4,473	3,286	4,815	4,886	23,894
Reference Case +EE+Solar	16,227	4,443	3,284	4,809	4,845	23,850
CPP-Existing	16,241	4,477	3,283	4,806	4,908	23,833
CPP-All	16,200	4,441	3,282	4,801	4,860	23,799
CPP-Existing +EE+Solar	16,214	4,477	3,281	4,796	4,912	23,793
CPP-All+EE+Solar	16,180	4,436	3,281	4,795	4,857	23,770
Beyond_CPP_Existing	16,206	4,442	3,282	4,800	4,858	23,808
Beyond_CPP_All	16,194	4,439	3,282	4,796	4,860	23,787

**Uses a 7% discount rate.*

6.2 Impact on Employment and Other Economic Indicators

Results suggest that the CPP and enhanced energy efficiency and solar policies can have mixed effects on three indicators of commercial and industrial economic activity (Table 6.2).

Table 6.2. Impacts on Manufacturing, Employment, and Commercial Building Square Footage, in 2030

	Value of Shipments (Billion $2009)	Employment, Manufacturing (Millions)	Commercial Floorspace (Billion Square Feet)
Reference Case in 2012	5009.3	11.8	82.3
Reference Case in 2030	7332.9	10.7	98.4
Reference+EE+Solar	7336.8	10.8	98.4
CPP-Existing	7283.4	10.6	98.3
CPP-All	7306.8	10.8	98.4
CPP-Existing+EE+Solar	7252.6	10.6	98.3
CPP-All+EE+Solar	7290.5	10.8	98.3
Beyond_CPP_Existing	7299.1	10.8	98.4
Beyond_CPP_All	7296.0	10.8	98.3

Source: Graf2000 Table 18/ Row 46

Policies to promote energy efficiency and solar appear to increase industrial value-of-shipments by approximately 0.1%, as can be seen by comparing the 2030 Reference case value, $7,333 (billion $2009), to the 2030 Reference+EE+Solar value, $7,337 (billion $2009). Adding the CPP with and without "EE+Solar" reduces the U.S. industrial sector's 2030 value of shipments, although the most severe impact of all scenarios amounts to only a 0.5% reduction in value-of-shipments.

Conversely, policies to promote EE and solar appear to increase employment in the manufacturing sector and more-than-offset employment-reducing effects of the CPP. While only 10.7 million people are employed in U.S. industrial activity in 2030 under the Reference case, approximately 150,000 more people are employed in U.S. industrial activity in 2030 for a total of 10.85 million under the Reference+EE+Solar case. Moreover, both the "CPP-Existing" and "CPP-All" cases reduce 2030 U.S. industrial employment relative to the Reference case, but with the "EE+Solar" increment, 2030 U.S. industrial employment is greater than in the Reference case.

Finally, the CPP and its interaction with "EE+Solar" policies seem to be drivers of commercial floorspace. While "EE+Solar" policies make no difference alone and the CPP reduces industrial floorspace, the CPP and "EE+Solar" policies together appear to increase commercial floorspace relative to CPP alone.

Based on these three indicators, it appears that enhanced energy-efficiency and solar policies may be able to mitigate negative impacts of the CPP in the industrial and commercial sectors and may have synergistic impacts with the CPP, creating employment and other economic benefits.

7. IMPACTS OF THE CPP IN THE SOUTH

The impact of CPP compliance on the mix of fuels to generate electricity will vary across the states and regions of the U.S. In particular, implementation of the Clean Power Plan in the South is likely to be different from CPP implementation in other regions. Unlike most of the rest of the country, the South is served by large, vertically integrated electric utilities, and has weak wholesale power markets. In addition, the South has a distinct electricity generation profile, although it is not monolithic. Within the South there is great diversity (Brown, et al., 2014).

The South has seen a dramatic increase in the fraction of electricity generation that has come from natural gas. In 1990, less than 10% of electricity generation in the South was produced using natural gas and 59% used coal compared to 34% of generation coming from natural gas in 2012 and 38% from coal. North of the Tennessee-North Carolina line (and further away from the nation's historic gas supply states), the shift to natural gas is much less pronounced.

The existence of new nuclear construction in the South further differentiates this region from the rest of the U.S. The South is constructing one new nuclear unit at Watts Bar in Tennessee, two units at Plant Vogtle in Georgia, and two units at V.C. Summer in South Carolina. The concentration of nuclear construction in the South is enabled by the regulatory structure in the South. Since the utilities are vertically integrated and investments in new generating assets are subject to oversight by public utility commissions or their counterparts,[21] firms are able to invest in technologies such as nuclear reactors more readily because they are obligated by their regulatory agencies to look over more extended horizons in making decisions that are in the long-term best interest of customers.

Availability of reasonably priced and reliable electricity has been a value to businesses and industry in the South and has helped to drive the region's economic development. Historically, residential, commercial, and industrial electricity rates in the South have been substantially below those of the rest of the country, though they have followed similar time paths. These low rates are influenced by the two-peak-season nature of the southern utilities, which lowers average costs. Looking ahead, electricity demand in the South is expected to grow more rapidly than in the rest of the country reflecting the region's relatively strong economy. While electricity rates are projected to rise in every region of the US, the South's rates are expected to remain below the national average (EIA, 2015a).

These historically low electricity rates have made energy efficiency and conservation less valuable; low electricity rates contribute to the region's intensive use of electricity, consistent with neoclassical economic principles of supply and demand. In addition, the South has invested less in these demand-side resources than other regions of the country as documented in Brown, et al. (2014). In 2014, the South accounted for 43% of U.S.

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[21] *The Board of Directors of the Tennessee Valley Authority regulates the electricity markets in the parts of the seven southern states that it serves.*

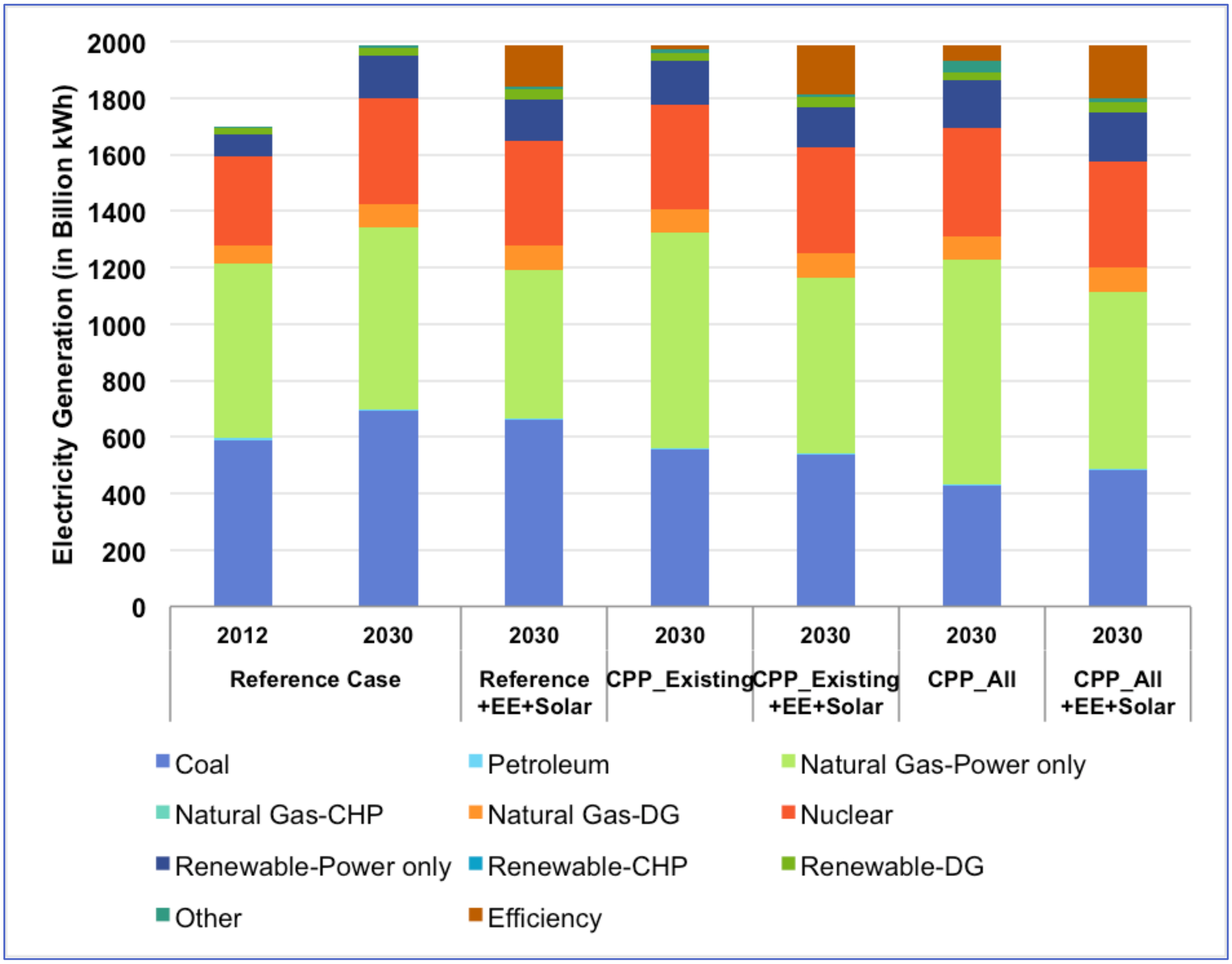
energy consumption and 43% of U.S. electricity consumption, but is home to only 36% of the nation's population and 35% of the U.S. GDP (EIA, 2015a). Thus, the region has high ratios of electricity per capita and GDP relative to the rest of the U.S. (Brown, et al., 2014).

7.1 Impacts on the Fuel Mix in the South

7.1.1 Impact of CPP compliance scenarios on the South's fuel mix

Figure 7.1 portrays the impact on the fuel mix in the South, calculated by aggregating values for the seven NERC regions that define the South (see). Comparing Figure 7.1 with Figure 4.4 highlights similarities and differences in the impacts of the CPP in the South versus the U.S.

Figure 7.1. Impact of CPP Compliance Scenarios on the South's Fuel Mix



Source: Graf2000 Table 62, Regions R1, R2, R12, R14, R15, R16, and R18, and Rows 81-88

Compared in proportional terms, the South serves as more fertile ground for the growth of a variety of leading-edge resources than does the rest of the United States under the

Reference case. First, the South's growth in coal lags that of the United State overall; coal tends to increase slowly in the South (i.e., by 4% vs 13% in the U.S.). The up-and-coming fuel for electricity generation, natural gas, increases its share of electricity generated proportionally more in the South (e.g., growing by 19% compared to 12% in the U.S.). Nuclear power also increases proportionally more in the South (i.e., by 17% over the Reference case, compared to 5% in the U.S.). The South shows proportionately more growth in renewable energy, increasing by 76% vs 51% nationwide; energy efficiency also grows more in the South than in the U.S.

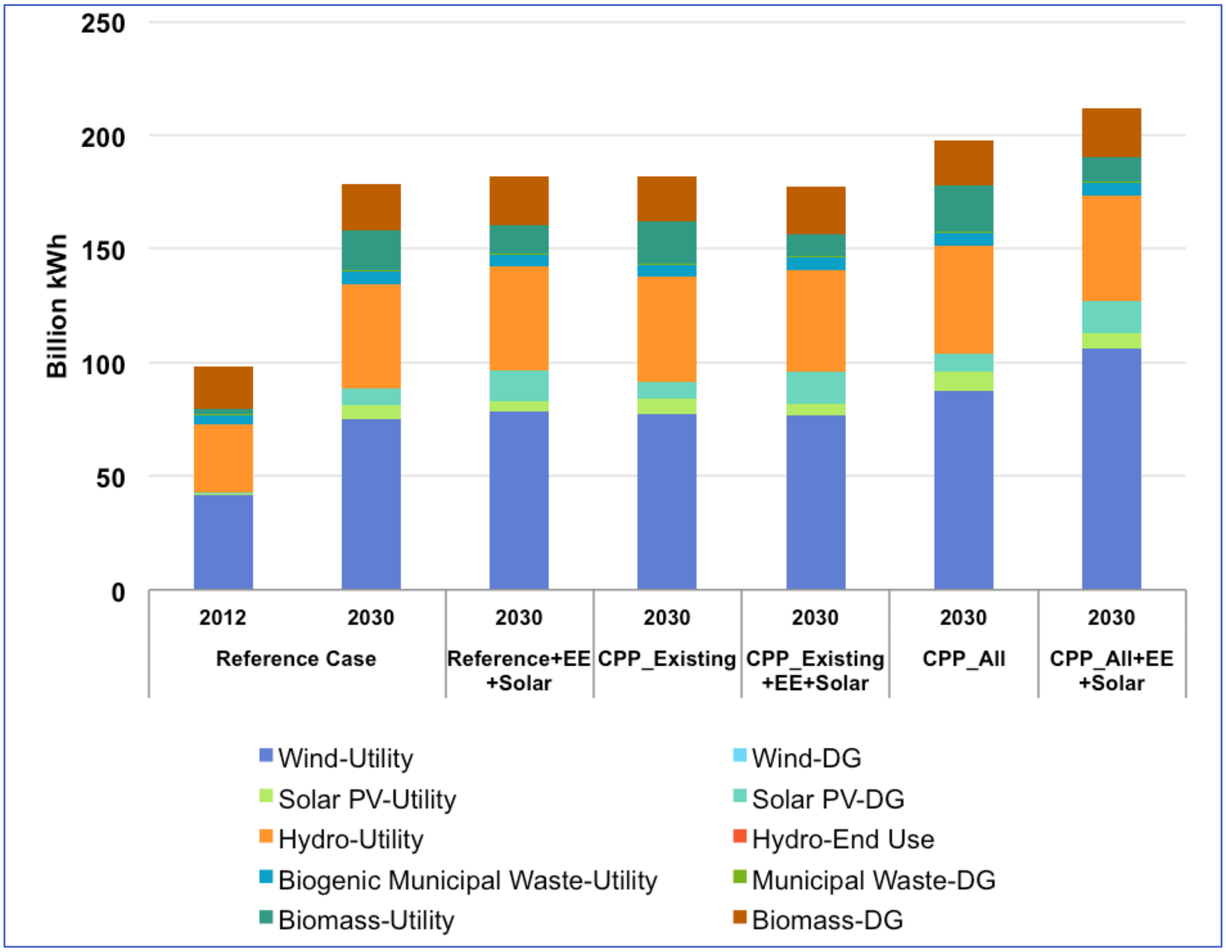
For nuclear generation in particular, the South exhibits great diversity across its constituent regions. Drilling down to the regional scale uncovers more significant rates of growth of nuclear generation in the Reference case for several southern NERC regions. These NERC regions include SRCE, SRSE, and SRVC, which cover Tennessee where Watts Bar unit 2 is nearing completion, Georgia where two units at Plant Vogtle are being built, and South Carolina where two units at V.C. Summer are under construction.

7.1.2 Renewable fuels in the South

In 2012, the South generated 6% of its electricity from renewable sources, less than the 12% national average.[22] While the the Reference case predicts that renewables in the South will grow more rapidly than in the rest of the country (nearly doubling between 2012 and 2030), they are still a smaller portion of the generation fuel mix in the South (9%) than in the U.S. (at 16%).

[22] *Spreadsheet calculation based on EIA data from http://www.eia.gov/electricity/data/state/)*

Figure 7.2. Mix of Renewable Generation in the South



Source: Graf2000 Table #67, Regions R1, R2, R12, R14, R15, R16, and R18, and Rows 18-24

While hydropower was the largest renewable generator of electricity in the U.S. in 2012, followed by wind power, the reverse is true in the South. Oklahoma and Texas contribute over 95% of the wind electricity generation in the South and they are responsible for much of the forecasted growth in renewables. In the South, hydropower provides nearly as much generation as wind in both 2012 and 2030, reflecting its growth potential particularly in the SERC subregions, underscoring the highly variable mix of electricity fuels across the South. In contrast, hydropower is not anticipated to grow noticeably in the rest of the U.S.

Following wind power and hydropower, biomass is the next largest renewable generator of electricity in the South, where it plays a much larger role than in the rest of the U.S. This renewable resource in the South includes about equal shares of utility-scale biopower and distributed biomass which is dominated by cogeneration systems at industrial sites such as pulp and paper mills. Electricity from municipal waste also falls into the category of biopower. All of these are anticipated to expand between 2012 and 2030, especially utility-scale biopower.

While solar is the smallest of the renewable resources in the South, its CAGR is greater than all other resources and its current status as "the resource to watch" makes the potential for solar in the South particularly interesting. Solar's explosive growth rate between 2012 and 2030 is partly driven by pro-solar utility regulatory policies, such as Georgia Power's Advanced Solar Initiative program. Growth of solar in the South is also driven by increasingly favorable economics, particularly for distributed installations. Notable is the proportion of the South's entire solar portfolio made up by distributed solar resources. The solar-promoting policies in the "EE+Solar" cases shift the South's solar portfolio toward a greater proportion of distributed solar generators, in addition to expanding the South's solar portfolio overall.

The U.S. and the South differ in interesting ways in terms of the mix of renewable resources that is forecast in the Reference case and in the CPP compliance scenarios. These differences are highlighted by comparing Figure 7.2 with Figure 4.10. Some of the main takeaways include:

- The U.S. uses a greater share of hydropower in its renewable portfolio than does the South, but the South is the only region where hydropower would grow in the Reference case. In both the U.S. and the South, carbon limits do not motivate hydropower to grow further. While there are alternative views about the potential for hydro to expand (Brown, et al., 2012), NEMS is not configured to consider the growth of hydropower at dams in the U.S. that currently are not generating electricity.
- While the compliance scenarios with enhanced "EE+Solar" increase solar power in both the U.S. and the South, the South's renewable portfolio mixture exhibits a proportionately greater uptake of solar, compared to the U.S., when solar PV costs are reduced.
- Biomass plays a greater role in the South's compliance strategies, than it does in the renewable portfolio of the U.S. Biomass rivals the growth of wind in the South, while wind power exceeds biopower in all of the compliance scenarios for the U.S.
- Wind, biomass and geothermal power account for most of the growth of renewables across the U.S. in the Reference case, while in the South, biomass, hydropower, and wind account for the greatest share of the growth of renewable electricity in the Reference case.
- In the U.S., geothermal power grows in the Reference case and does not grow further, to any degree, in the compliance scenarios. Its role in the South is negligible and remains small.
- Similarly, none of the compliance scenarios would show measurable growth of electricity from biogenic municipal waste or solar thermal sources in either the U.S. or the South.
- Solar resources grow quickly in the South, and their growth is aided by solar-promoting policies under the "EE+Solar" scenarios. The "EE+Solar" compliance

scenarios expand the South's solar portfolio and shift the South's solar portfolio towards a greater proportion of distributed solar resources.

7.2 Impacts on Electricity Bills in the South

In the Reference case, economy-wide electricity bills per capita (across all customer classes) are expected to increase by 12% between 2012 and 2030 as the result of environmental regulations, increasing demand, and other factors (Table 7.1).[23] When enhanced energy efficiency and solar policies are added to the Reference case, electricity bills per capita would increase by less than 1% between 2012 and 2030.

In the compliance scenarios that simply impose carbon constraints, electricity bills would increase approximately 3% more in 2030 compared with the Reference case forecast, rising by about 15%. However, with enhanced energy efficiency and solar, the compliance scenarios generate economy-wide electricity bills per capita that are lower than those forecast for 2030 in the Reference case, saving every person in the U.S. an estimated $104 in 2030 (in $2013), with similar savings in earlier and later years, as well. These savings allow households and businesses to purchase additional goods and services that expand employment and increase economic activity.

In summary, compliance with the CPP mass-based goals can be achieved while curbing the increase in per capita electricity bills forecast by the Reference case. These financial benefits are greater in the South than for the U.S. at large because the energy efficiency savings are larger per capita in the South than in the U.S.

Table 7.1. Impact of the CPP Compliance Scenarios on Electricity Bills Per Capita in the South in 2030 (in $2013)*

Scenario	Households	Businesses	Industry	All Sectors
Reference Case 2012	562.1	395.0	200.8	1157.8
Reference Case 2030	619.2	439.8	236.1	1296.9
Reference+EE+Solar	531.7	421.2	209.9	1164.7
CPP-Existing	632.1	451.1	245.3	1330.4
CPP-Existing+EE+Solar	536.9	398.0	211.8	1148.6
CPP-All	646.5	462.7	253.5	1364.5
CPP-All+EE+Solar	544.5	404.9	216.3	1167.6
Beyond-CPP-Existing	541.8	402.6	213.8	1160.0
Beyond-CPP-All	542.8	403.3	215.1	1163.0

** The South is defined by three of the nine Census Divisions.*
Source: Graf2000 Table 8, Rows 50-52, and 54; Table 2, Row 152; Table 3, Rows 6, 13, 23, and 54

[23] For more information on electricity prices and expenditures by sector at http://www.eia.gov/state/seds/seds-data-complete.cfm?sid=US#PricesExpenditures

7.3 Hybrid Rate-Mass Scenario Results for the South

The choice between rate- versus mass-based standards will likely depend upon an array of key state considerations. Rate-based standards may be best able to accommodate the potential for demand growth; they could actually result in a rise in carbon emissions if increasing output overwhelms the reductions from lower carbon intensive power (Murray, et al., 2015). Mass goals more directly target emissions levels. They put a price on each ton of CO_2 reduction and provide a revenue stream for states to address equity and other issues. Rate-based approaches involve a subsidy on low-carbon generation and a tax on CO_2 emissions, which some suggest should reduce costs (Johnson, 2006; Murray, et al., 2015). They also may require that states forego control over credit revenues, because credits are sold by covered generators. Another consideration is the ability to engage in interstate trading. Rate-based states can only trade credits with other rate-based states, and the same is true for mass-based states (Larsen, et al., 2016a). State decisions may also be influenced by the level of their power exports, the availability of in-state abatement options, and the existence of multi-state utility service territories. One final consideration is administrative convenience: mass-based approaches generally require lower upfront administrative costs.

Table 7.2. Percent Renewable Generation in the Hybrid Compliance Scenario: The South (Rate-Based) vs. the U.S. (Mass-Based)

	Region	
CPP-All+EE+Solar	**South**	**Non-South US**
2030	10.2%	27.7%
2040	12.2%	29.8%
CPP-Hybrid+EE+Solar		
2030	9.6%	28.6%
2040	10.2%	31.4%

In the hybrid scenario – where the South is the one region that uses rate-based goals – we expect that the South would increase its penetration of renewables relative to CPP compliance using mass-based goals because southern states with an abundance of renewables can trade with other states in the South, but not with states elsewhere.

We test this by comparing, within the hybrid results, the South to the rest of the nation, and by comparing the hybrid results to the "CPP-All+EE+Solar" results. In the rate-to-mass comparison, we also examine the differential outcomes between the seven NERC regions that comprise the South.

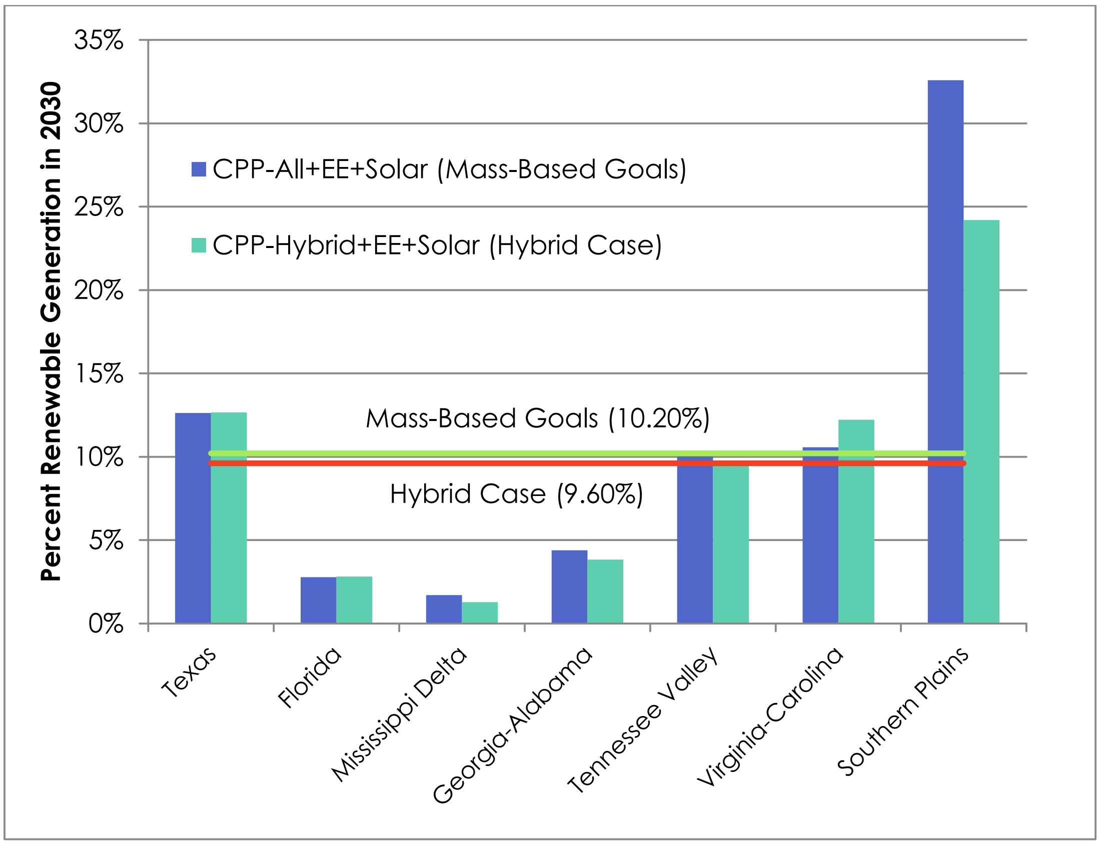
In the hybrid case, rate-based goals appear to shift the South's power portfolio away from renewables. Table 7.2 shows the comparative results between the South and the rest of the U.S., across the "CPP-All+EE+Solar" and the "CPP-Hybrid+EE+Solar" scenarios. In 2030, the South's proportion of renewable energy is 10.2% under the "CPP-All+EE+Solar" scenario, but is only 9.6% under the "CPP-Hybrid+EE+Solar" scenario. In the rest of the nation, the hybrid scenario produces more renewables.

Under both scenarios, the South's proportion of renewable energy is much lower than that of the rest of the U.S. In 2030, the Rest of the U.S has 27.7% renewables under the

"CPP-All+EE+Solar" scenario, and has more (28.6%) under the "CPP-Hybrid+EE+Solar" scenario. The gap continues through 2040 (Table 7.2).

Results also show that much slower growth in renewables occurs in the hybrid vs. "CPP-All+EE+Solar" case in the Southern Plains region, starting from a large penetration of wind today. Conversely, the greatest increase in renewable generation occurs in the Virginia-Carolina region.

Figure 7.3. Percent Renewable Generation in 2030



Source: Graf2000 Table #67, Regions R1, R2, R12, R14, R15, R16, and R18, and Rows 18-24

While the hybrid scenario enhances renewable energy growth in the South, the growth comes with the caveat of potential lost opportunities from choosing a compliance pathway that differs from the rest of the nation. Trading with other regions could reduce compliance costs for the South, because trade would allow the South to generate revenues from either selling ERCs or buying ERCs at costs below marginal abatement costs. However, EPA only allows trading under certain conditions; EPA specifies that regions must have the same type of goals to be "trading-ready," and this only applies to trading across states that have mass-based goals and trading across states that have subcategory-specific rate-based goals.[24] Statewide-rate-based goals are not considered trading-ready, meaning that states electing to meet a statewide-rate-based goal must submit additional evidence that trading with other states will amount to equivalent emissions reductions in each state. If the South chooses a type of goal that other regions do not, the South must undertake additional efforts to demonstrate that the South can trade with other regions for equivalent emissions reductions. Therefore, the South must weigh any cost-reductions from complying with a rate-based goal against lost opportunities for cost reductions through trading with regions that have the same kind of goal. Table 7.3 does not indicate that cost reductions are associated with rate-based trading, since the cumulative net present value of total resource costs in the South are higher under the rate-based than the mass-based approach. This is inconsistent with the expectations described by Johnson (2009) and Murray et al. (2015).

Table 7.3. Cumulative Net Present Value of Total Resource Costs in the South (Rate-Based) and the Rest of the U.S. (Mass-Based) (in billions 2013$)

	Region	
CPP-All+EE+Solar	**South**	**Non-South US**
2030	733.1	802.8
2040	873.5	946.5
CPP-Hybrid+EE+Solar		
2030	754.6	809.8
2040	892.0	955.0

[24] For further information on the implications of the type of goal chosen by a state with regards to trading, see the Clean Power Plan 2015 Final Rule, Section VIII.

8. ADDITIONAL CO_2 REDUCTION OPPORTUNITIES

In keeping with the theme of looking "beyond the Clean Power Plan," we explore the possibility of forward-thinking governors, mayors and industrial leaders taking actions to reduce carbon emissions below the reductions required by the Clean Power Plan. States such as California, for example, have already announced intentions of going beyond the requirements of the Clean Power Plan. In August 2007, the Western Climate Initiative announced a regional, economy-wide greenhouse gas emissions target of 15% below 2005 levels by 2020.[25] Similarly, the annual average CO_2 emissions from electric generation sources covered by the Regional Greenhouse Gas Initiative (RGGI) in the Northeast are predicted to be 45% lower in 2020 relative to 2005 emissions.[26] Hawaii has a goal of achieving 100% renewable electricity generation by 2045 (Lincoln, 2015).

We hypothesize that parts of the U.S. will differ in their ability to go beyond the requirements of the Clean Power Plan. Prior analyses have shown that the Clean Power Plan leads to differential marginal abatement costs across areas of the U.S. (Niemeyer 2016, Ross, Murray, and Hoppock 2015). The differential marginal abatement costs will be affected by the relative stringency of each state's respective emissions goal and each state's choice of compliance strategy. Beyond these goals and compliance strategies, differential marginal abatement costs reflect variable marginal abatement supply curves, which are a function of current levels of dependence on coal generation, the geography of renewable resources, the ability to improve end-use efficiency, and an array of other factors.

We therefore expect that, if policy measures are introduced that increase the costs of emissions, areas of the United States will exhibit variable responses in terms of their incremental CO_2 emissions reductions. The hypothesis of differential marginal abatement supply curves would be supported by observed differentials in CO_2 emissions abatement in response to emissions-price-increasing measures.

We simulate a policy measure that increases the costs of emissions by introducing a CO_2 price in 2022. Our CO_2 price is introduced in 2022 in tandem with the introduction of the Clean Power Plan itself, so as to simultaneously increase the marginal value of abatement measures. Increasing the marginal value of abatement measures makes more-expensive abatement options cost-effective. By observing which regions make further carbon reductions in response to the increase in the shadow price of emissions, we can see which regions have a relatively high "carbon-shadow-price elasticity of abatement."

We layer our CO_2 price on top of the CPP_All+EE+Solar scenario. We find the CPP_All+EE+Solar scenario particularly important to investigate, as the scenario represents a leakage-controlling mass-based policy on top of the more-updated of our two reference scenarios. As leakage control is required by the Clean Power Plan, we find

[25] http://www.c2es.org/us-states-regions/regional-climate-initiatives#WCI
[26] http://www.c2es.org/us-states-regions/regional-climate-initiatives#WCI

the CPP_All+EE+Solar scenario to present many realistic features that make it worth scrutinizing under the additional CO_2 emissions price.

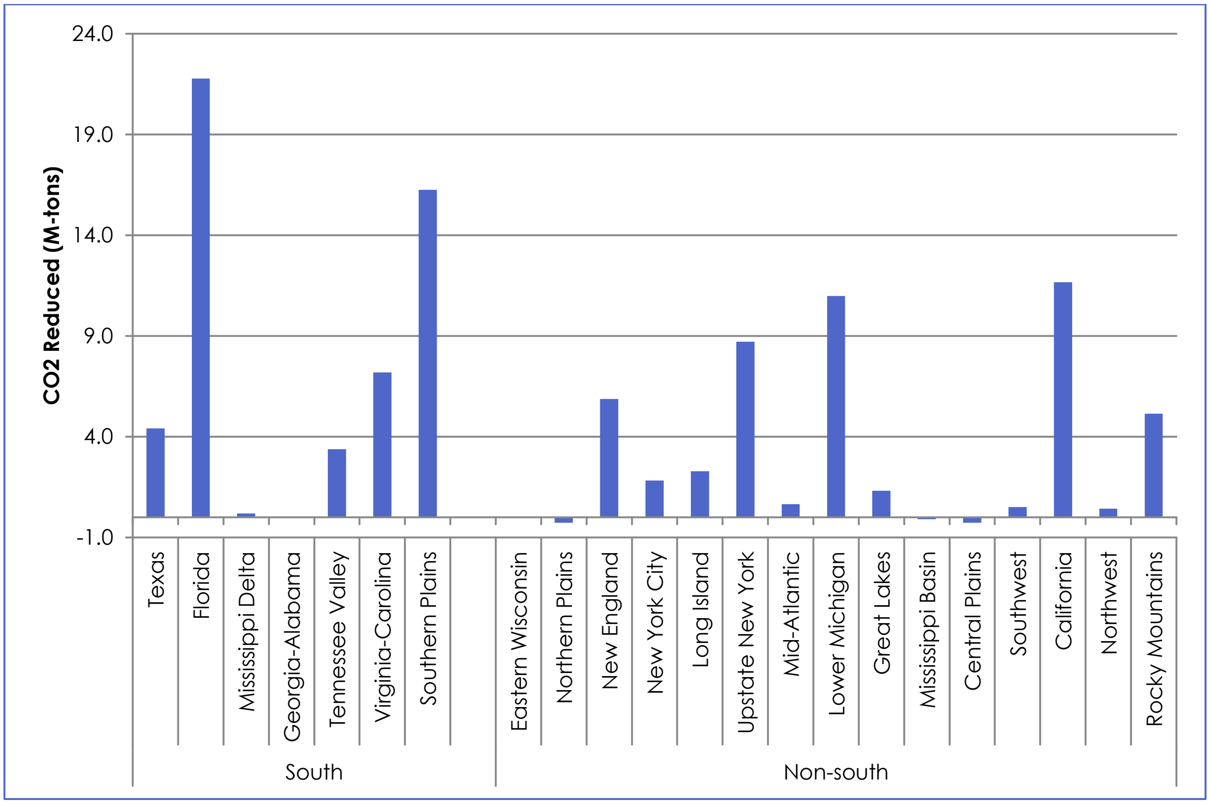
8.1 CO_2 Abatement Beyond the Clean Power Plan Across Regions

To observe how much farther beyond the Clean Power Plan a hypothetical set of forward-looking policies could go, we compare the 2030 CO_2 emissions outcomes for the the CPP_All+EE+Solar scenario with and without the elevated CO_2 price. Referring to earlier in the paper, Table 4.1 presents these comparisons. We see that 2030 electric sector CO_2 emissions under the CPP_All+EE+Solar scenario amount to 1,762 million short tons, while 2030 electric sector CO2 emissions under the CPP_All+$20Fee+EE+Solar amount to 1,659 million short tons. As such, forward-looking policymaking appears capable of achieving approximately 103 million short tons (5.8%) more CO_2 abatement than policymaking under the CPP_All+EE+Solar scenario.

To test the hypothesis that CO_2 abatement elasticities differ across regions, we observe the CO_2 abatement behavior of each region in response to the increased shadow price of carbon. We compare the CO_2 emissions under the CPP_All+EE+Solar scenario to the CO_2 emissions under the scenario that adds a $20 carbon price, labeled "CPP_All+EE+Solar_2022fee." A relatively large increase in a region's CO_2 abatement between the two scenarios signals that the region lies at a relatively elastic point on its marginal abatement cost curve, while relatively lesser changes represent a region that lies at a relatively inelastic point on its marginal abatement cost curve. The former region will be well-equipped to meet the vision of forward-looking policymakers, while the latter region may need to rely upon interregional trade in order to fulfill a forward-looking abatement strategy.

We observe the differences in regional CO_2 abatement between the two scenarios in Figure 8.1. Our hypothesis of differential elasticities of abatement holds under Figure 8.1, which shows that the regions differ dramatically in terms of their incremental CO_2 abatement under the added CO_2 price. While we see large incremental abatements in Florida and the Southern Plains, for example, we see almost no change in regions such as the Mid-Atlantic and the Southwest. Moreover, a few regions such as the Mississippi Basin and the Northern Plains show small increases in CO_2 emissions (i.e. decreases in abatement), which could be due to emissions allocations via interregional trade of electricity. Our scenarios do not allow trading of compliance allowances, but trading of electricity between regions is allowed and does occur, perhaps shifting emissions in ways that lead to small emissions increases for some regions under more-stringent policies. From Figure 8.1, we can see that some regions such as Florida and the Southern Plains will have a great advantage in complying with forward-looking policies, while other regions such as the Mid-Atlantic, Southwest, Mississippi Basin, and Northern Plains may need to rely on interregional allowance trading compacts to comply with forward-looking policies.

Figure 8.1. Incremental CO_2 abatement by region in 2030



Source: Graf2000 Table 62, Row 151

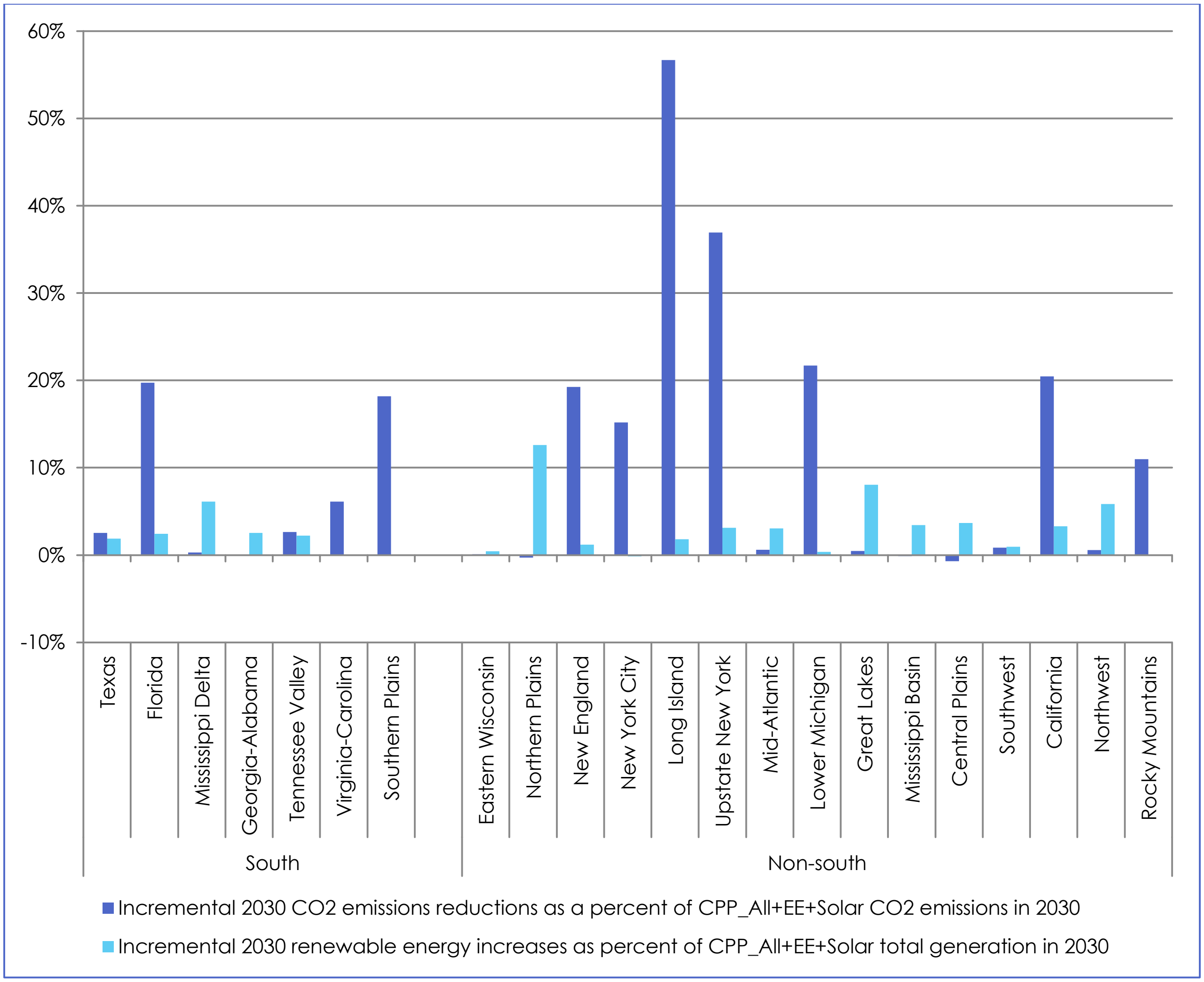
8.2 Renewable Resources as a Marginal Abatement Measure

To explore mechanisms behind regional incremental CO_2 abatement observed in Figure 8.1, we examine the incremental renewable generation in each region in 2030 and compare it to the CO_2 abatement behavior in 2030. We normalize both CO_2 abatement and renewable generation differences in 2030 between the CPP_All+EE+Solar and the CPP_All+EE+Solar_2022 fee cases against the CO_2 emissions and total generation in 2030 in the CPP_All+EE+Solar scenario, respectively. The normalized values, as percentages of their respective totals, appear in Figure 8.2.

Figure 8.2 demonstrates that many of the regions that incrementally abate a high percentage of their total emissions when the CO_2 fee is introduced do not incrementally deploy a high percentage of renewable generation. California, Upstate New York, and the Southern Plains represent examples of regions with high incremental abatements and low incremental renewable energy deployments. Conversely, many regions that incrementally deploy a high percentage of their total renewable generation when the CO_2 fee is introduced do not abate a large percentage of their CO_2 emissions. The

Northern Plains, the Mississippi Delta, and the Great Lakes represent this trend. These would appear to be regions that reach a tipping point for renewable resources.

Figure 8.2. Opportunities for Further Renewable Generation Deployment Based on the Shadow Price of Carbon



Source: Graf2000 Table 62, Row 151; Graf2000 Table 67, Row 26.

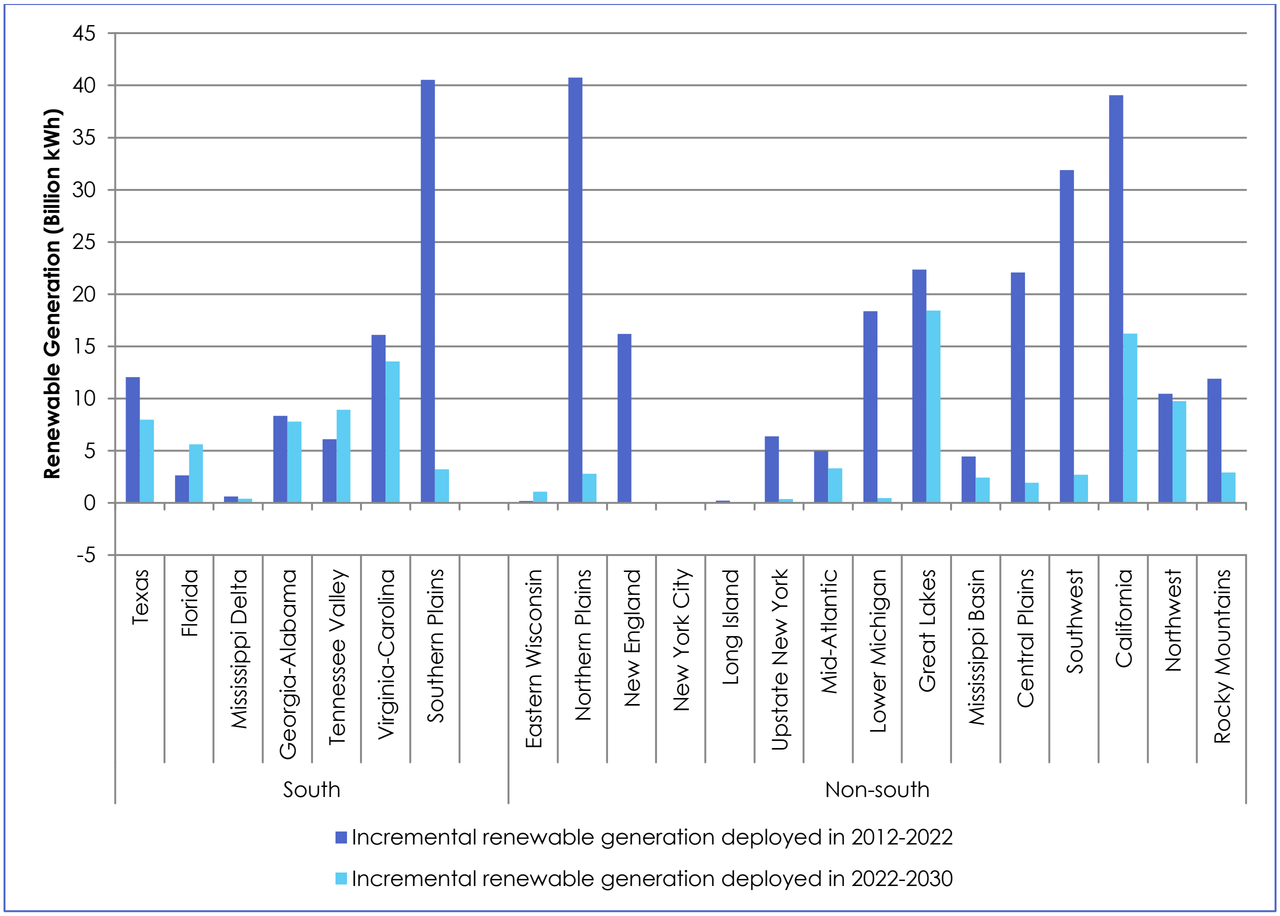
8.3 Tipping Points for Renewable Generation?

Beyond looking at incremental CO_2 abatement actions, the section also examines the important sensitivity of further renewable deployment to forward-looking policies and programs for mitigating climate change. The renewable energy industry is in dynamic transition, with many changes that were once thought impossible coming from the solar industry in particular (Keith 2016). Forward-looking policymakers could capitalize on the Clean Power Plan by taking the lead in the renewable energy industries through policy measures. We hypothesize that regions will be differently-abled to capitalize on the Clean Power Plan for driving renewables, however, and that some regions will find greater ease-of-success than others under forward-looking policies and programs. That is, some regions may find a "tipping point" by implementing forward-looking policies in tandem with the Clean Power Plan; other regions may not.

We assess the relative potential for each region to achieve at tipping point and jump ahead in renewable energy deployment by examining the timing of renewable deployment under our CPP_All+$20fee+EE+Solar scenario. We compare the renewable generation outcomes against the hypothesis that there regions will exhibit a skewed distribution in deployment of renewable resources after the $20 fee is enforced in 2022. We interpret regions that deploy the most renewables only after 2022 will be those that are best-positioned to take advantage of the Clean Power Plan with forward-looking policies for renewable deployment.

The adjacent bar charts in Figure 8.3 shows the amount and timing of utility-scale renewable resources deployments by region in our CPP_All+$20fee+EE+Solar scenario by displaying the quantity of utility-scale renewable generation deployed between two periods: 2012-2022 and 2022-2030. As shown in Figure 8.3, most of the regions that deploy significant incremental utility-scale renewable energy in 2022-2030 are regions that have already deployed an equal or greater amount of utility-scale renewable energy in 2012-2022. Nine regions deploy levels of utility-scale renewable generation during the Clean Power Plan that are comparable to the levels deployed by the region in 2012-2022. Examples of regions that deploy incremental utility-scale renewable energy in 2022-2030 comparable to their deployments in 2012-2022 are Georgia-Alabama, Great Lakes, and Virginia-Carolinas. Regions that deploy more utility-scale renewable energy during the Clean Power Plan compliance period than during 2012-2022 are Florida, Tennessee Valley, and Eastern Wisconsin. Conversely, several regions deploy a far lesser amount of utility-scale renewable generation during 2022-2030 than deployed during 2012-2022; examples of such regions include Southern Plains, Northern Plains, Central Plains, and the Southwest. Our hypothesis of differential ease of capitalizing on the Clean Power Plan for promotion of utility-scale renewable generation holds under the evidence shown in Figure 8.3. The evidence shown in Figure 8.3 also suggests that regions seeking to lead the utility-scale renewable energy industries should take advantage of the PTC/ITC extension and build momentum prior to the Clean Power Plan. Only regions that have a strong base of utility-scale renewable deployment prior to 2022 seem able to take advantage of the opportunity for accelerating utility-scale renewable generation during the Clean Power Plan compliance period and reach a tipping point for their renewable resources.

Figure 8.3. Incremental utility-scale renewable generation deployment before the $20 fee and during the $20 fee and Clean Power Plan compliance period

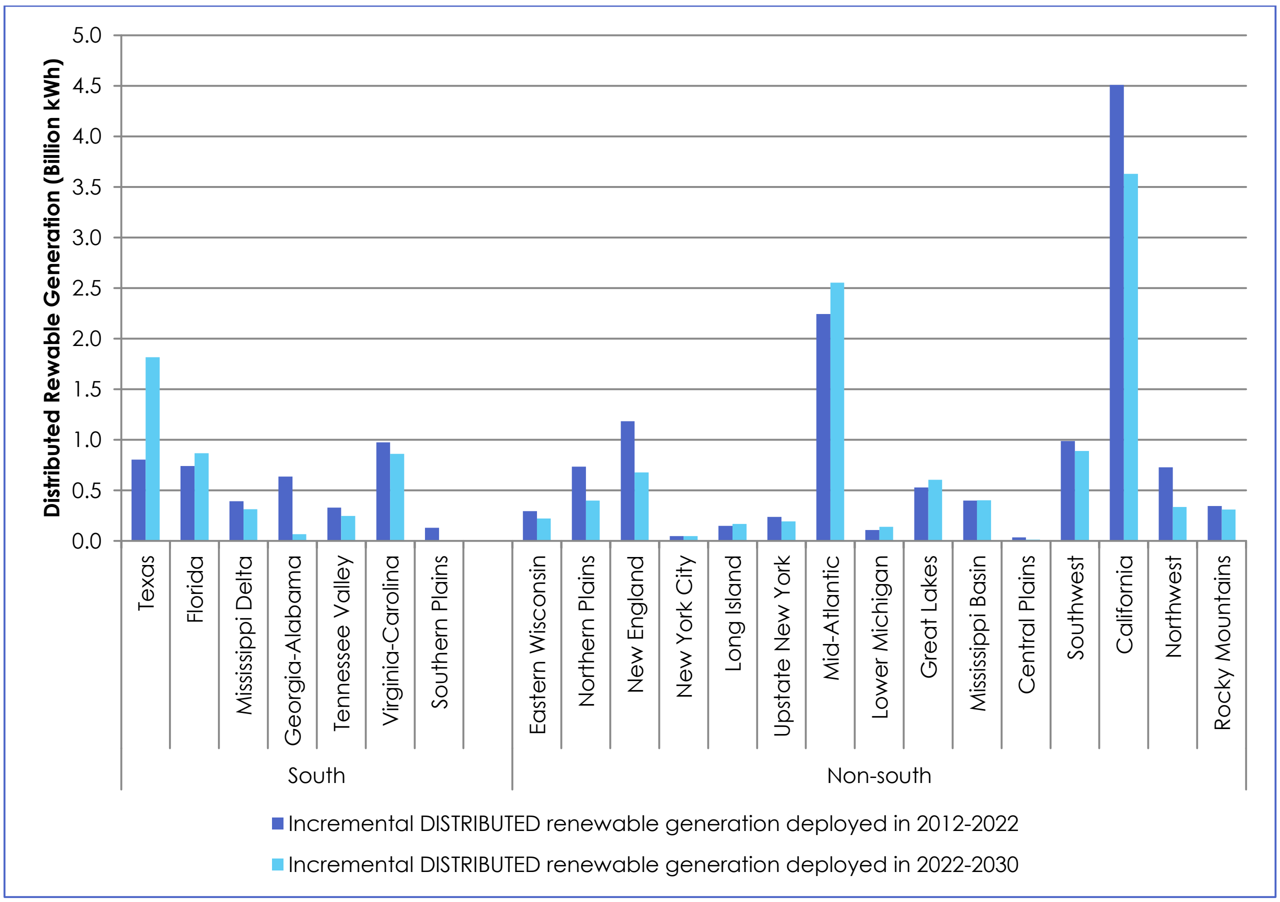


Source: Graf2000 Table 67, Row 26.

To gain further insight into the opportunities presented by the Clean Power Plan for deployment of renewable resources, this section also examines the deployment of distributed renewable resources – for example, rooftop solar, micro-hydro, and so forth. As distributed resources are gaining momentum, and particularly distributed solar, we seek to understand what role these resources might play under forward-looking policies and programs toward climate change mitigation. We hypothesize that regions will exhibit a skewed distribution in terms of incremental distributed renewable energy deployment before the Clean Power Plan (2012-2022) and during the Clean Power Plan (2022-2030).

Each region's distributed renewable energy deployment before the Clean Power Plan (2012-2022) and during the Clean Power Plan (2022-2030) is shown in Figure 8.4. Similarly to the pattern of utility-scale renewable resource deployment, most of the regions that deploy significant distributed renewable energy resources during 2022-2030 have also deployed similar levels of distributed renewable resources in 2012-2022. A few regions, such as Texas and the Mid-Atlantic, deploy more distributed renewable resources during the Clean Power Plan compliance period (2022-2030) than during 2012-2022. The Georgia-Alabama region deploys noticeably fewer distributed renewable resources during 2022-2030 than during 2012-2022. Our hypothesis of a skewed distribution holds less strongly under the evidence shown in Figure 8.4, however, because it seems that most regions do follow a similar pattern of deploying an amount of distributed renewable resources during 2022-2030 similar to the amount deployed in 2012-2022. Nevertheless, it seems that regions seeking to use forward-looking policymaking to take leadership in the distributed renewable energy industries should take advantage of ITC/PTC and other favorable policies well in advance of the Clean Power Plan's compliance period. Only regions with a legacy of distributed renewable generation prior to the Clean Power Plan seem to achieve a tipping point in their renewable resources during the Clean Power Plan.

Figure 8.4. Incremental distributed renewable generation deployment before the $20 fee and during the $20 fee and Clean Power Plan compliance period



Source: Graf2000 Table 67, Row 51.

Overall, it seems that opportunities for forward-looking policymaking to abate CO_2 emissions beyond the requirements of the Clean Power Plan may need to use alternative policies if the preferred mitigation outcome is to increase renewable generation. Moreover, electricity trade between regions regardless of interregional allowance trading may provide opportunities for forward-looking policymaking to reduce emissions beyond the requirements of the Clean Power Plan.

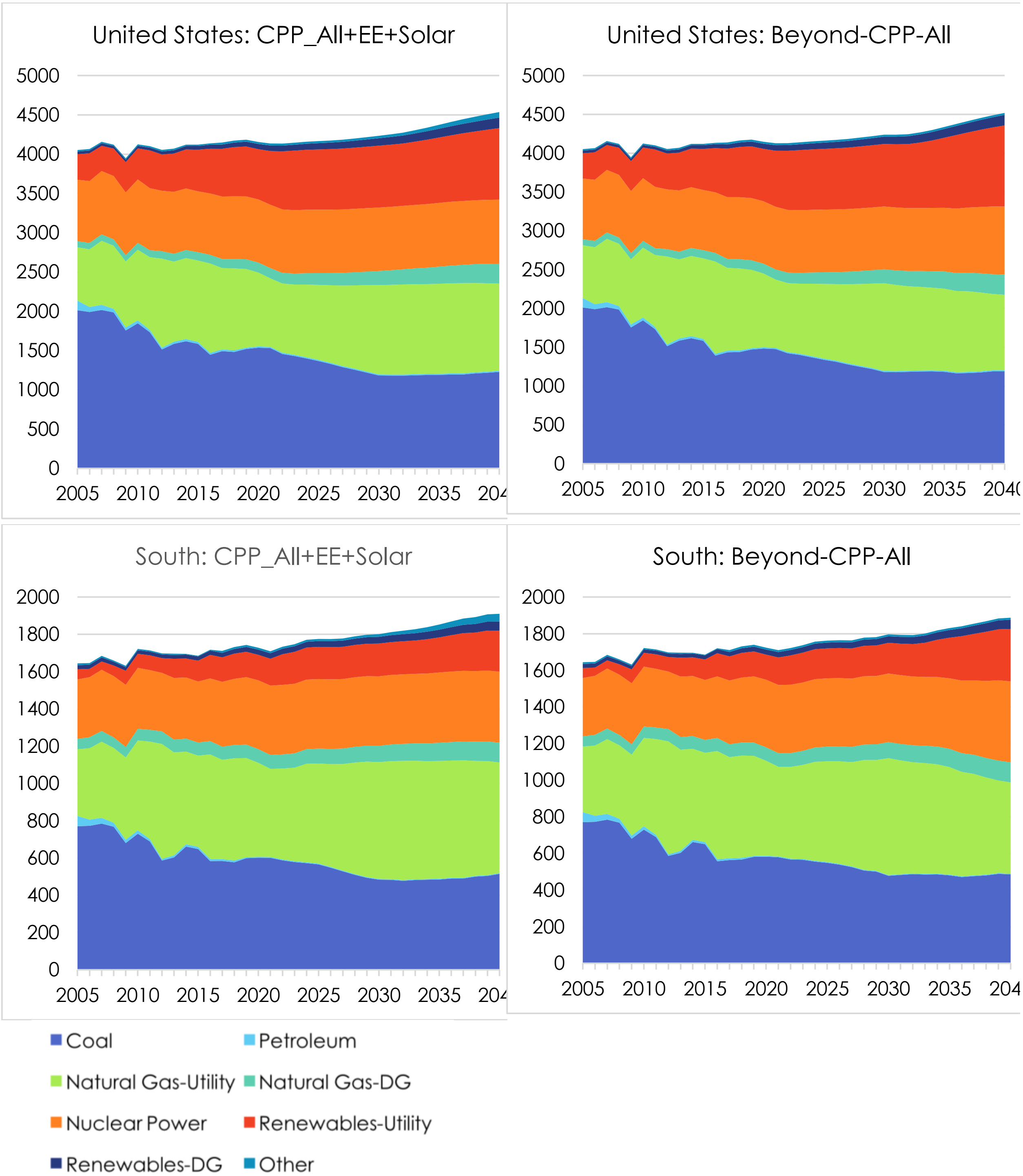
8.4 Post-2030 Carbon Mitigation Policies

To complete our assessment of "beyond CPP" futures, we examine the impact of post-2030 carbon mitigation policies on near-term least-cost energy planning. We focus primarily on the "Beyond CPP All" scenario, which is the "CPP-All+EE+Solar" scenario with a $20-ton price on carbon (in $2013) applied to all electricity sector activities from 2031-2040. The results are shown for the U.S. and the South in Figure 8.5.

The "Beyond-CPP-All" scenario, in combination with the perfect foresight feature of NEMS, would create a fuel mix transformation over the next 15 years that is distinct from the other compliance scenarios described thus far. Specifically, more coal would be retired over the next 15 years (and beyond), less natural gas capacity and infrastructure would be added, and more renewable generation capacity would be built in the near term (Figure 8.6).

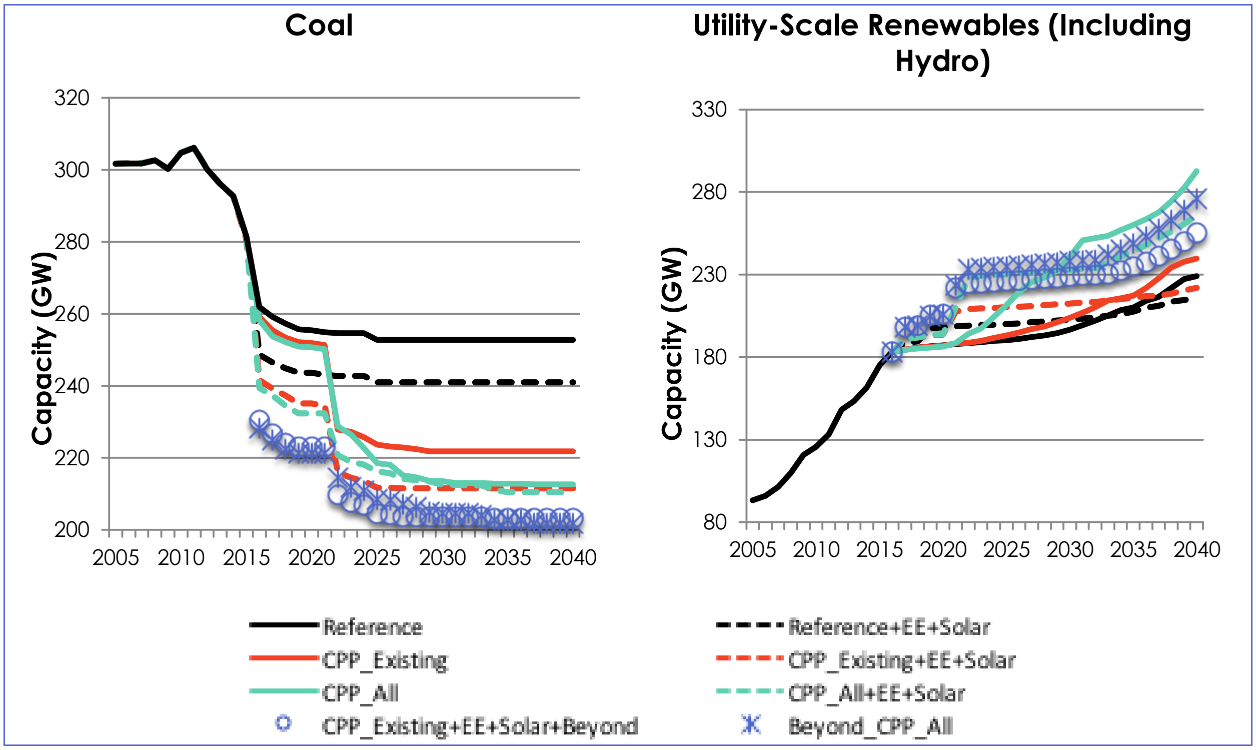
This scenario would avoid the lock-in of fossil fuels that would unnecessarily increase the cost of compliance over the long term. As shown in Table 5.3, the NPR of total resource costs in 2030 in the Reference case are $90 billion larger than in the "Beyond-CPP-All" scenario. Even with the inclusion of the incremental investment costs required to pay for the "efficiency premium," total costs will be less than in the Reference case.

Figure 8.5. Impact of Continued Mitigation Policy on the Least-Cost Fuel Mix



Source: Graf2000 Table 8, Rows 6-20.

Figure 8.6. Impact of Continued Mitigation Policy on Coal and Renewable Capacity



9. SUMMARY AND CONCLUSIONS

Since the release of the Clean Power Plan, stakeholders across the U.S. have vigorously debated the pros and cons of different options for reducing CO_2 emissions from existing power plants. States have an array of options to meet their carbon-reduction goals, including both demand- and supply-side resource investments. Administratively, states need to choose between adhering to an emissions intensity goal or an equivalent CO_2 mass-based goal; politically, they can also prepare an individual state or a multistate implementation plan. Using GT-NEMS, we focus on examining the effectiveness, costs and benefits of scenarios that comply with mass-based goals applied across 22 regions of the U.S.

Our key findings are summarized below.

- Mass-based goals are met by all four compliance scenarios, ranging from electric sector CO_2 emission reductions of 34% in 2030 relative to 2005 when both existing and new EGUs are regulated and EE+Solar policies are added to 26% when only existing EGUs are regulated and the EE+Solar features are excluded.
- The benefits of reducing CO_2, SO_2 and NOx nearly reach $100 billion in the year 2030 (in $2013) across the CPP compliance scenarios. The co-benefits from local pollution abatement exceed the benefits from carbon mitigation.
- The CPP scenarios would double the pace of fossil-plant retirements. In 2030, 15% of the electric power sector EGUs in 2012 would be retired.
- Natural gas combined cycle units phase in rapidly as other fossil units are retired, particularly when only existing EGUs are regulated. Renewables and energy efficiency gain a larger share of the fuel mix when mass-goals for all EGUs are implemented, especially when the EE+Solar features are added. The build-up of natural gas infrastructure is therefore less challenging as resource investments become more diversified.
- Distributed and utility-scale solar grows rapidly in the Reference case and in all compliance scenarios. The additional load reduction from energy efficiency policies primarily offset the growth of natural gas generation.
- Per capita electricity bills are forecast to increase by 12% between 2012 and 2030. Higher increases would occur in the compliance scenarios if EE+Solar features are not included. Electricity bills could drop back to 2012 levels if EE+Solar policies are added.
- Our modeling estimates that in 2030, total resource costs would be approximately 6% higher in the two CPP compliance scenarios that only cap emissions, compared with the Reference case. In contrast, they would be approximately 3% lower in the compliance scenarios that also include "EE+Solar" features.

- The fuel mix transformation over the next 15 years would be distinct with foresight that policies will require more carbon emissions reductions through 2040. Specifically, more coal would be retired and more renewable capacity would be added in the near term, thus avoiding the lock-in of fossil fuels that would increase the cost of compliance over the long term.

The South's response to the CPP is similar to the rest of the U.S., but with some distinction. In general, the South responds to the CPP with a greater proportion of coal retirements and a larger percent increase of natural gas, energy efficiency and renewable resources, especially wind, distributed solar, and utility-scale biomass.

In conclusion, CPP compliance with the enhanced deployment of energy efficiency and reduced solar costs could achieve EPA's carbon reduction goals nationwide and in the South. Along with producing a low-carbon power system, we have identified CPP compliance strategies that could produce an array of collateral benefits including lower electricity bills across all customer classes, greater GDP growth, and significant improvements in local air quality. The virtue of thinking ahead to the possibility of an additional phase of carbon mitigation has also been shown. Choices made today should avoid the legacy of a suboptimal energy infrastructure that could burden subsequent generations.

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11. APPENDIX

Table App.1. NERC Region Labels and Population Growth Rates

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Number	Geographic Name*	eGRID	NEMS		
1	Texas	ERCT	ERCT	21,926,489	335,820
2	Florida	FRCC	FRCC	17,737,979	222,936
3	Eastern Wisconsin	MROE	MROE	2,463,739	157
4	Northern Plains	MROW	MROW	12,265,621	57,952
5	New England	NEWE	NEWE	14,444,865	28,565
6	New York City	NYCW	NYCW	8,175,133	3,611
7	Long Island	NYLI	NYLI	2,832,882	1,251
8	Upstate New York	NYUP	NYUP	8,370,087	3,697
9	Mid-Atlantic	RFCE	RFCE	24,919,722	105,001
10	Lower Michigan	RFCM	RFCM	9,415,466	11,892
11	Great Lakes	RFCW	RFCW	37,386,227	116,845
12	Mississippi Delta	SRMW	SRDA	8,641,966	58,034
13	Mississippi Basin	SRMV	SRGW	7,417,047	48,672
14	Georgia-Alabama	SRSO	SRSE	14,781,887	201,852
15	Tennessee Valley	SRTV	SRCE	13,905,143	119,605
16	Virginia-Carolina	SRVC	SRVC	20,298,216	159,695
17	Central Plains	SPNO	SPNO	3,809,001	19,828
18	Southern Plains	SPSO	SPPS	6,868,658	55,590
19	Southwest	AZNM	AZNM	11,030,359	188,530
20	California	CAMX	CAMX	36,996,232	295,969
21	Northwest	NWPP	NWPP	17,095,654	165,786
22	Rocky Mountains	RMPA	RMPA	5,487,768	94,842

**Geographic names are approximately descriptive.*

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Table App. 2. Project Participants and Stakeholders

Coverage	Academic /Researcher	Consultant /Advocate	Federal Gov't	Industry/ Utility	State Agency	Think Tank	Grand Total
National	6	16	8	10		9	**49**
Regional	27	5	5	9	1		**47**
Alabama		1			5		**6**
Arkansas		2			3		**5**
Florida		1			9		**10**
Georgia		11		1	13		**25**
Kentucky		2			6		**8**
Louisiana					4		**4**
Maine		1					**1**
Mississippi		1			6		**7**
No. Carolina	1	1			12		**14**
So. Carolina		4			6		**10**
Tennessee		3		2	8		**13**
Virginia		1			4		**5**
West Virginia					3		**3**
Grand Total	**34**	**49**	**13**	**22**	**80**	**9**	**207**

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