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Green Corridors

Linking Interregional Transmission Expansion and Renewable Energy Policies

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RESOURCES FOR THE FUTURE

Green Corridors: Linking Interregional Transmission Expansion and Renewable Energy Policies

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Abstract

A variety of recent policy measures have been advanced to promote interregional power transmission investment in the United States; among these are the designation of corridors on federal lands in western states and the identification of national interest electric transmission corridors across the country. Although these corridors have been put forward as critical policy interventions to modernize an aging transmission system, their effectiveness could be undermined by parallel policies, such as renewable portfolio standards (RPSs), designed to alter the landscape for new investment in generation capacity. This paper presents the results of a scenario analysis of the relationship between the interregional power grid and renewables policies to evaluate 1) the effects of state and national RPS policies on interregional power flows and 2) the impacts of transmission expansion on the locations and types of new, renewable sources for electricity capacity additions. Using the RFF Haiku Electricity Market Model, we find that the locations of transmission corridors could have a significant impact on the location, type, and marginal cost of generation in the future. Conversely, a national RPS would induce interregional power flows across the country significantly different from those that would prevail in the absence of such a policy. In particular, a national RPS would promote western renewables and shift power flows to the East. Under either a set of state-level RPS policies or a national RPS, the majority of power flowing into California will come from the Pacific Northwest, not from the Southwest, which is where corridors are most abundant. Additionally, a national RPS could motivate more than 10 GW of new biomass capacity in the Southeast, but grid expansion could shift 6 GW of this capacity to the Plains states and western wind.

Key Words: energy corridors, transmission grid, renewable electricity, RPS

JEL Classification Numbers: Q42, Q48

Contents

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1. Introduction

Siting, permitting, and financing of electric power transmission lines are expensive processes fraught with uncertainty. It is therefore not surprising that investments in new transmission lines are limited and that some regions of the country experience transmission congestion that raises electricity prices and diminishes grid reliability. Were this congestion not present, the marginal cost of electricity generation, net of transmission costs and losses, would be homogeneous across the contiguous United States. Instead, several states in the Northeast, Southeast, and West face electricity prices that are higher than their neighbors' partly because of grid congestion that limits their capability to import power.[1] This discrepancy is largely attributable to congestion on transmission lines that connect the coasts to the interior.

A variety of barriers to new transmission investment and construction contribute to this grid congestion. On the investment side, the locational marginal pricing model put forward by the Federal Energy Regulatory Commission has met with limited success in promoting efficient transmission investment. The market structure appropriate for interregional transmission lines—that is, lines at the interface between regional transmission organizations—has been a particularly thorny issue in this regard (Benjamin 2007). Other barriers to transmission line siting include environmental constraints, public opposition, and regulatory roadblocks. These obstacles existed even under vertical integration of utilities and coordinated generation and transmission planning; however, siting difficulties have multiplied under deregulation. In the wake of the 2003 Northeast blackout and the 2001 California electricity crisis, the need for coordinated

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[1] The average retail electricity prices in the four census divisions that cover the two coasts was 10.2 cents/kWh in 2006. This is 31 percent higher than the 7.7 cents/kWh average retail price in the five census divisions that do not touch the coasts over the same period (EIA 2007b).

generation and transmission expansion, even in deregulated markets, has become widely recognized (Joskow and Tirole 2004).

Collectively, barriers to transmission grid expansion have uneven effects for technology and policy. Large-scale grid-connected renew able generation technologies are particularly disadvantaged by their geographic locations, which are often far from the current transmission lines and load centers. Policies focused on renewable energy development, like renewable electricity standards and any broader climate change legislation, also depend on the transmission grid. Therefore, grid policy must in turn account for the renewable resources that demand transmission interconnection.

Several policy measures have been advanced to promote transmission investment and address siting difficulties associated with new projects, including the development of federal energy corridors, priority areas, and routes for new power lines. Parallel to these efforts to boost transmission construction, a range of policy initiatives have also emerged to address climate change concerns and other environmental issues. Renewable portfolio standards (RPSs) are recent examples of policies that seek to shift the electricity generation industry toward less carbon-intensive fuels. These policies will affect the types and locations of electric power plants built over the coming decades.

As the electric power sector shifts toward greater use of renewable resources, transmission policies and renewable policies must be evaluated jointly. This paper presents modeling results for several scenarios at the intersection of these policies to examine how increases in transmission capacity under state and national RPS policies could affect changes in the locations and amounts of conventional and renewable energy generation, electricity and renewable energy credit (REC) prices, and carbon dioxide emissions. The next section provides a brief overview and background on energy corridors and RPS policies. Section 3 describes the selected policy and technology scenarios modeled, and the Haiku Electricity Market Model is described in Section 4. Section 5 contains the results of the modeling analysis. Section 6 concludes with a discussion of policy implications and opportunities for more in-depth policy-focused research.

2. Linking Transmission and Renewables Policies

Transmission planning in the United States is driven by the locations of power plants relative to the locations of loads, or areas with high demand for electricity (Hirst and Kirby 2001). Prior to the deregulation of the electricity industry, vertical integration of utilities and flexibility in locating fossil fuel–based generation allowed joint planning of investment in transmission and generation facilities in areas that were best suited to meet anticipated load growth over long time horizons. Today, about one-third of the electricity consumed from the power grid in the continental United States is traded in deregulated electricity markets,[2] and the flexibility to locate fossil fuel generators has diminished.[3] Transmission expansion now occurs largely without the planning advantages of an integrated system and within markets that are dynamic on both the supply and the demand sides.

This difficult planning environment for power transmission has introduced increased uncertainty for investments in generation facilities. This is especially true of renewable energy facilities, such as wind farms, where fuel is costless, operating costs are typically lower than fossil generation facilities, and capital costs, including transmission, are often a significant component of total project costs. Because renewable energy resources are often located in remote locations, greater reliance on renewable electricity generation will also result in a geographic shift in the location of generation capacity, which will in turn have repercussions for the location of new transmission investments to address interregional transmission congestion. Conversely, adequate existing transmission access is also likely to be a driver of early large-scale, grid-connected renewable energy development. Because electricity generation currently is primarily based on fossil fuel–burning facilities, the infrastructure necessary to transport both fuel and power has been constructed accordingly. Renewable energy has only recently emerged as a policy and technology priority, and the transmission grid is central to meeting goals for new development. As a result, two major policies that could shape the future of renewable energy involve energy corridors and state and federal RPS mandates. These policies are described individually in this section to highlight important gaps and overlaps between transmission and renewables policies.

[2] As of April 2007, the following jurisdictions had deregulated electricity markets: ME, NH, MA, CT, RI, NY, NJ, PA, DE, MD, DC, OH, MI, IL, and TX (EIA 2007c). In 2006 these states and the District of Columbia consumed 36 percent of all retailed electricity in the lower 48 states (EIA 2007b).

[3]Fossil fuel–fired generators have become more difficult to site because of tightening air pollution standards and access to factors of production, including fuel, infrastructure for fuel transport, and water for cooling.

2.1 Energy Corridor Designations

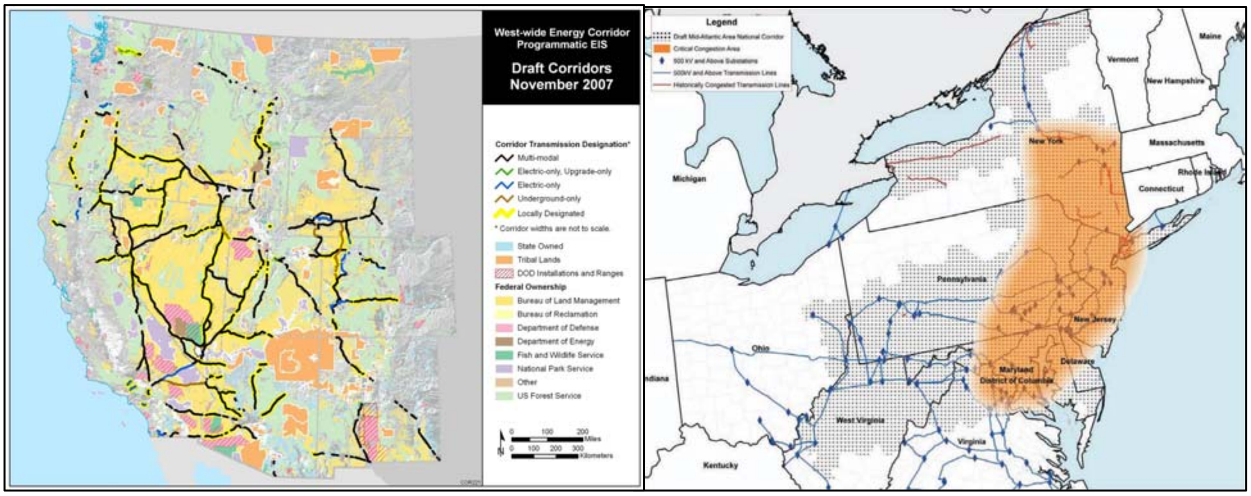
One of the most prominent recent efforts to promote transmission investment and address siting difficulties associated with new projects[4] is a mandate in the Energy Policy Act of 2005 to find locations for energy corridors on federal lands. These corridors are intended to ease regulatory roadblocks and simplify permitting processes for multiple types of networked infrastructure, including oil and gas pipelines, hydrogen pipelines, and electric power lines in the designated rights-of-way (DOE 2007). The effort is currently targeted at establishing major interstate corridors connecting 11 western states but it is intended to serve as the basis for future designations in the eastern part of the country. Additionally, a parallel process to identify national interest electric transmission corridors (NIETCs) was recently completed, and two broad priority areas were identified—along the eastern seaboard in the Northeast, and parts of southern California, Arizona, and Nevada in the Southwest.[5]

Figure 1 shows the draft designations of western energy corridors and the final northeastern NIETC. Numerous criteria have driven the locations of all these sites; however, in large part, corridors are located along preexisting rights-of-way in areas that are currently experiencing significant transmission congestion. There has been limited attention to the long-term drivers of electricity generation that could inform the corridor-siting process or how added transmission capacity in the selected corridor locations to date could influence the development of new generation infrastructure, such as renewable energy facilities.

[4] In July 2006, the Federal Energy Regulatory Commission issued “Promoting Transmission Investment through Pricing Reform.” Under this rule, the commission provides developers of new transmission infrastructures with options for incentive-based policies that could help promote cost recovery and profitability of new transmission investments (FERC 2006). In spring 2007, it approved a California ISO recommendation that the initial cost of transmission lines built to access areas with significant renewable development potential be incorporated into the utilities transmission tariff, with the balance of costs to be paid by generators connecting to the line on a pro rata basis (FERC 2007).

[5] For the purposes of this study, we use the term *corridor* to encompass both the federal energy corridors in the West and the NEITC designations across the country and to reflect priority areas for transmission expansion across the country. More information on the West-wide corridor and NEITC designation processes are available at http://corridoreis.anl.gov/ and http://nietc.anl.gov/ respectively.

Figure 1. Federal energy corridors and national interest electric transmission corridors. Left: Draft corridor designations (black) on federal lands in 11 western states. Right: Area designated as northeastern NEITC (orange).



2.2 Renewable Portfolio Standards

As of May 2007, renewable portfolio standards with binding targets had been enacted or renewed in 25 states and the District of Columbia.[6] These standards mandate that utilities generate or purchase a minimum percentage of the state's electricity from renewable sources (Herzog et al. 2001; Rabe 2006). Each state has rules for how to meet its standard using within-state or imported electricity from a combination of renewable energy sources, most commonly wind, solar, biomass, and geothermal resources (Rabe 2006). RPSs vary in the degree of flexibility in which technologies are allowed and which must be used in certain amounts by specific dates.

In addition to the set of state standards already in place, efforts have also been made on Capitol Hill to advance a national RPS. Several bills with provisions for a federal renewable

[6] This count includes Hawaii, which is outside the scope of the HAIKU model (contiguous 48 states only). Additionally, three states (Missouri, Virginia, and Vermont) have established voluntary programs and renewable energy goals; however, we do not model these voluntary renewable energy policies in this study. A summary of state RPSs based on the Database of State Incentives for Renewables & Efficiency (DSIRE) is available at the DOE Energy Efficiency and Renewable Energy website: http://www.eere.energy.gov/states/maps/renewable_portfolio_states.cfm.

electricity standard have been proposed in the 110th Congress, mandating, for example, the creation of a 15 percent national RPS by 2015.[7]

The grid is essential infrastructure for renewable energy facilities. As a result, problems with siting new transmission lines are likely to affect the development of renewable energy sources (Vajjhala 2006; Vajjhala and Fischbeck 2007). And in fact, despite the national attention to promoting renewable energy, siting renewable energy facilities remains a difficult and uncertain process. One of the most notorious examples of the barriers to large-scale renewable energy development is Cape Wind, the first U.S. offshore wind farm, proposed off the coast of Massachusetts. This project has moved slowly through years of high-profile opposition to both the wind farm itself and its associated transmission line. Because renewable generation facilities are often confined to remote, inflexible locations where natural resources are abundant, transmission infrastructure is critical; yet as the Cape Wind project illustrates, finding locations for new power lines in these areas can be more difficult than in less pristine or less isolated areas (Vierima 2001; Vajjhala and Fischbeck 2007).

Although transmission access is widely understood to be an underlying factor in the success or failure of any RPS, renewable electricity standards are political instruments and typically are not based on engineering or economic assessments of transmission capability and renewable resource potential. As a result, renewable electricity generation and power transmission availability are not as tightly coupled at the policy level as they inherently are at the project level. At the scale of renewable resource development required to meet current state RPSs and any potential national standard, this divergence between renewable development and transmission expansion brings the adequacy and reliability of the grid into sharper focus. The next sections describe our modeling approach to jointly evaluating corridors and RPS policies using the Haiku Electricity Market Model.

3. Policy and Technology Scenarios

This study is focused on the chicken-and-egg relationship between renewables policies, specifically state or national renewable portfolio standards, and interregional transmission

[7] Federal RPS provisions are included in Senate Bill S. 1419 and House Bill H.R. 2950, both titled The Renewable Fuels, Consumer Protection, and Energy Efficiency Act of 2007, placed on the calendar in the Senate by Senator Reid in May 2007 and introduced in the House by Representative Wilson in June 2007. Similar proposals have been developed by Senator Bingaman, Representative Udall, and others.

capability. RPS policy will affect interregional power flows, and transmission capability will in turn affect the outcomes of RPS policy. We examine the influence of each of these on the other. The effects of RPS policies on interregional power flows are considered for RPS scenarios specified at two geographic levels, the regional level (as a proxy for modeling state RPS policies) and the national level. In general, demand for transmission will depend upon where renewable generators emerge under each type of policy. State policies are likely to drive more dispersed renewables development than a national policy. This difference has implications for transmission planning and grid reliability.

For renewable portfolio policies, state-level policies will tend to have smaller implications for the interregional power flows than policies that encompass larger geographic regions. Interregional power flows depend on differences in regional marginal generation costs because power tends to flow from regions with low marginal cost to regions with relatively higher marginal cost. Because an RPS is a quasi-tax on electricity generation by nonrenewable generators, the first-order economic effect of a portfolio standard is a wealth transfer to renewable generators from nonrenewable generators that raises the average cost of power generation in the portfolio standard region. However, this policy tends to have a smaller effect on the marginal cost of generation in the region imposing an RPS and thus a smaller effect on differences in marginal cost across regions, which is the determinant of electricity trading.[8]

The effect on the marginal cost of power generation depends on the particulars of the electricity supply curves in each region at each moment in time. The marginal effects need not be monotonic in portfolio standard stringency, and their sign is generally not known (Fischer 2008). The general pattern that can be anticipated is that the marginal effects at the geographic level of the portfolio standard will be small and swamped by the inframarginal effects. Since the implications of any policy for interregional transmission are circumscribed to the marginal effects of the policies, state-level portfolio standard policies, such as California's RPS, could have significant intraregional effects concentrated on neighboring states, but they are not likely to have wider implications for interregional power flows.

In contrast, the effects of a national RPS on interregional power flows will be greater than the effects of any set of state-level RPSs designed to achieve the same level of total renewable

[8] This same effect holds true for "clean energy portfolio standard" policies that include nuclear and/or large hydropower generation facilities alongside renewables.

generation. Under a state policy, where RECs can only be generated locally, the wealth transfer from nonrenewable to renewable generators is intrastate, and thus the small marginal effects of such a policy are manifest in the supply curve for electricity in each state that implements the policy. Under a national portfolio standard policy, the wealth transfer is interstate, and thus the effects on each region's supply curves can be substantial. The result is a redistribution of power generation activity that will create greater interregional power flows and increase the potential for transmission congestion—but it also increases opportunities for congestion relief from a reconfiguration of the grid.

The circular relationship between RPS policy and interregional transmission capability is evaluated in this paper using scenario analysis. RPS policy is specified as either a set of state-level policies aggregated to model regions or a single national policy overlaid on existing state policies. Transmission capability is specified under a dynamic algorithm to create scenarios with decreasing levels of interregional transmission congestion. The following subsection describes the development of a baseline scenario and the renewables policy scenarios. The subsection thereafter describes the algorithm for creating interregional transmission capability expansion scenarios.

3.1 Baseline and Renewables Policy

RPS is only one among several types of policies and incentives intended to spur investment in renewables. Another major policy intended to support renewables is the federal renewable energy production tax credit (REPTC). The effect of an REPTC policy is to simply lower the cost of power generation for those technologies qualified to receive the tax credit. Currently, a production tax credit of $19/MWh is made available to new wind, geothermal and dedicated biomass generators. A credit of $9.50/MWh is available to new landfill gas and non-dedicated biomass generators.[9]

REPTC-type policies tend to have similar effects irrespective of the scale of the geographic region encompassed by the policies. The average cost of power generation will fall under an REPTC policy, but the marginal cost will not increase. The impacts of an REPTC

[9] Since the federal REPTC has repeatedly been renewed just prior to lapsing and has actually lapsed once before being reinstituted, it is modeled in perpetuity in Haiku as a tax credit that is received with 90 percent probability. The current Energy Policy Act of 2005 version of the federal REPTC program is set to expire at the conclusion of 2008 but is likely to be renewed. Senator Pete Domenici (R-N.M.) addressed the issue by saying, "I strongly believe that the renewable energy tax credits should be extended …" (E&E Daily 2008).

program on interregional power flows and grid congestion depend on the particulars of the geographic specification of the policy and the geographic location of renewable resources. An REPTC program that crosses interregional boundaries will tend to force power generation into the encompassed regions with relatively cheap marginal renewable capacity and away from the regions with relatively expensive marginal renewable capacity. At the borders of an REPTC program, power generation will tend to move into the regions encompassed by the policy. Consider a set of state REPTC policies that achieve the same levels of state power generation by renewables as an alternative federal REPTC policy. The relative magnitude of the effects of these policies on interregional power flows and the opportunities for congestion relief from power grid expansion are generally not known.

Because REPTC and RPS policies can exist simultaneously, we evaluate the individual and collective impacts of these two types of renewable energy incentives. We have analyzed a set of scenarios that include various combinations of a national-level REPTC policy and state- and national-level RPS policies. For all these scenarios, the transmission grid is held at a business-as-usual level of 1 percent annual growth in total transfer capability between regions. The results of this analysis establish that when sustained into the future, the REPTC is a potent policy instrument that largely washes out renewable energy capacity additions motivated by state RPSs alone.

Even in the absence of a national RPS policy, the federal REPTC in conjunction with the state RPS policies achieves a level of renewable penetration that is sufficient or nearly sufficient to satisfy a national RPS of 15 percent in 2020. Thus a scenario including both the federal REPTC and the national RPS is rejected as the basis for testing the effects of removing interregional transmission constraints, on the grounds that the effects of the national RPS are largely not present because it is made mostly slack by the federal REPTC. With minimal costs necessary to comply with the national RPS, the implications of national RPS for interregional transmission are difficult to assess. To compare the role of state RPSs to a national standard, we choose to define a baseline scenario that includes a representation of all existing state-level RPS policies but does not include a federal REPTC.

The RPS policies of each state were obtained from the Database of State Incentives for Renewables and Efficiency (DSIRE) in May 2007. These data present several problems for electricity modeling at the regional level. The first is general policy specification heterogeneity. For example, some of the state RPS policies are specified as capacity floors denominated in MW, whereas others are specified as generation floors denominated in MWh. Similarly, some policies are generation-based RPSs, which are specified in MWh as a percentage of within-state generation, and others are consumption-based RPSs. Some of these latter standards further allow imported renewable electricity or renewable energy credits to meet a MWh target as a percentage of consumption. Second, RPS policies also vary in technology inclusiveness, where some states include solar power, some hydro, others neither. Different states also prioritize or “weight” specific resources. For example, a MWh generated with solar power is awarded 2.4 MWh of renewable energy credit toward meeting an RPS target in Nevada. Finally, some states distinguish RPS obligations between investor-owned and public utilities. To deal with this heterogeneity, all policy specifications are recalibrated using exogenous projections of capacity and output to be in equivalent terms in which all renewables except hydro qualify for renewable energy credits and the RPS floor is set as a percentage of consumption in MWh.

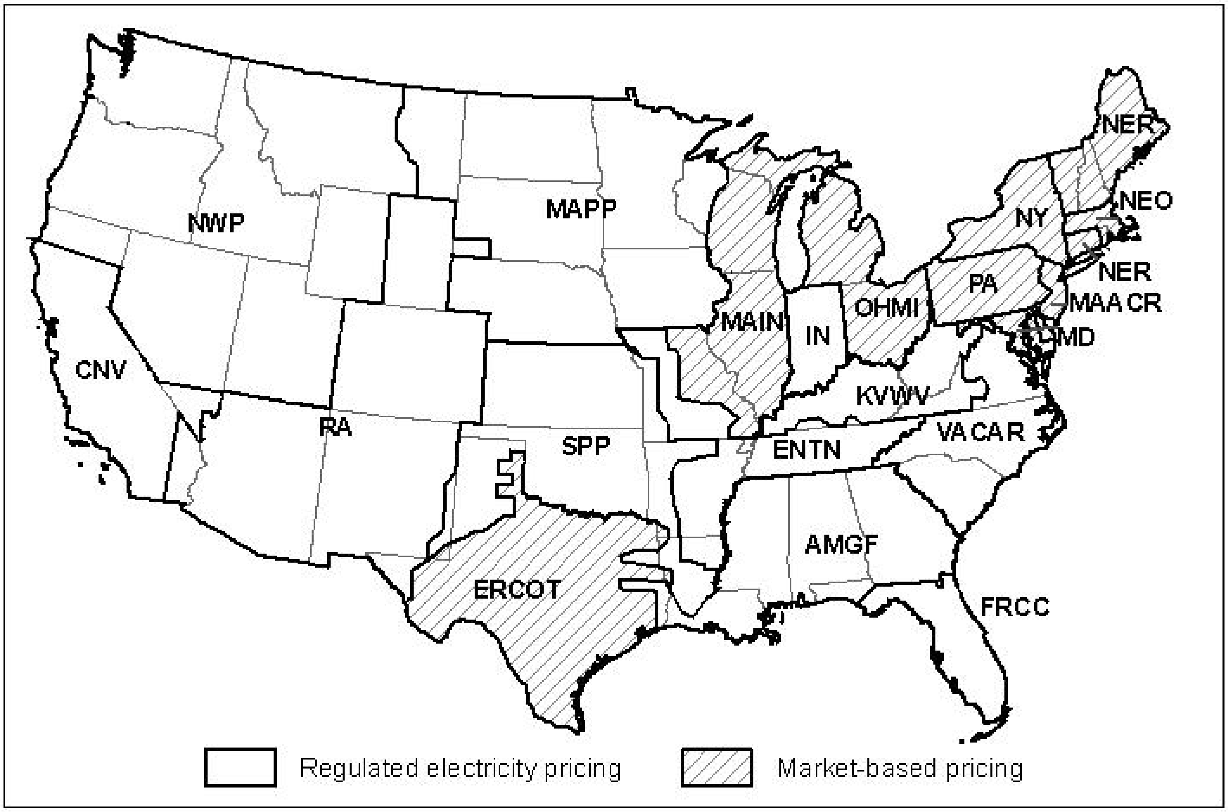
A second issue with state-level RPS data relates to the Haiku Electricity Market Model. Haiku solves not at the state level but at the more aggregate level of 20 Haiku market regions (HMRs). Our approach is to aggregate the state RPS policies into a specification at the HMR level. This is achieved by weighting individual state RPSs by a historic level of state electricity consumption to find the regional consumption-weighted average RPS by HMR, as shown in Table 1. Figure 2 shows the geographic boundaries of the HMRs. The reference in Figure 2 to electricity pricing regimes is addressed Section 4.

Building on this characterization of state RPSs for the baseline scenario, the state RPS baseline is then compared with a scenario in which a national RPS is enacted above and beyond all existing state RPSs. The national RPS policy baseline stipulates that in 2010, renewable resources must generate a quantity of electricity equivalent to at least 5 percent of national electricity consumption. This percentage rises by 1 percent each year to reach a 20 percent floor in 2025. States with RPSs more stringent than the 20 percent national standard are modeled as meeting the higher standard. The generation sources modeled as qualifying to receive RECs under the national RPS are those that derive power from wind, biomass, geothermal, solar, and landfill gas. The next subsection describes how these state and national scenarios are subject to incremental expansions of the grid for interregional power transmission.

Table 1. Regional consumption-weighted average renewable portfolio standards, by Haiku market region

Haiku market region	*2010*	*2015*	*2020*	*2025*
OHMI	—	—	—	—
KVWV	—	—	—	—
IN	—	—	—	—
ERCOT	4.2%	6.6%	6.09%	5.5%
MAACR	5.1%	9.2%	16.8%	16.8%
MD	5.5%	7.5%	7.5%	7.5%
PA	3.0%	5.5%	8.0%	8.0%
MAIN	2.9%	7.0%	7.0%	7.0%
MAPP	4.1%	7.1%	8.8%	10.8%
NY	—	7.0%	7.00%	7.00%
NER	8.3%	9.2%	10.1%	11.0%
NEO	5.1%	10.1%	15.1%	19.5%
FRCC	—	—	—	—
AMGF	0.1%	0.1%	0.1%	0.1%
ENTN	—	—	—	—
VACAR	0.2%	0.3%	0.4%	0.4%
SPP	0.5%	0.8%	0.8%	0.7%
NWP	3.4%	8.2%	8.7%	8.7%
RA	5.6%	10.9%	14.5%	15.8%
CNV	19.3%	25.9%	31.9%	31.9%

Figure 2. Haiku market regions, regulated and deregulated



3.2 Incremental Transmission Expansion

To evaluate how patterns of renewable capacity additions might shift under different trajectories of interregional transmission capacity expansion for both the state and the national RPS scenarios, we develop an iterative interregional transmission capability expansion algorithm. The algorithm for loosening the constraints on interregional transmission operates on a reference level (either state RPS or national RPS) to create an expanded transmission grid. All transmission lines from either reference level that carry at least 85 percent of their total capability at least 10 percent of the time in 2020 are expanded in each iteration by the full amount of transmission capability available at that regional interconnection in the reference model. This expansion includes all years after and including 2020. After this new model is solved, the algorithm is applied again in equal increments until all transmission congestion between neighboring model regions is alleviated. In other words, the transmission expansion algorithm is repeated until none of the transmission lines meet the criteria for further expansion.

The final model, then, is a simulation of electricity markets in the absence of interregional transmission constraints.

The incremental transmission expansion algorithm makes it possible to identify locations where transmission capacity additions have the greatest impact on renewable energy capacity additions under both the state and the national RPS scenarios. The expansion of the grid is exogenously imposed upon the model by the algorithm described above, which incrementally loosens the constraints on interregional transmission capability. These scenarios do not address the incentives of the owners or potential owners of the transmission grid because the costs of transmission expansion are not considered. The approach does identify where transmission planners, such as the federal agencies responsible for designating corridors, could have the biggest impact on reducing interregional transmission congestion. The next section describes in detail the model used to evaluate the scenarios.

4. Haiku Electricity Market Model

The electricity supply analysis conducted in this paper relies on a detailed simulation model of the electricity sector known as the Haiku Electricity Market Model,10 which is maintained by Resources for the Future. Haiku is a deterministic, highly parameterized model that calculates information similar to the National Energy Modeling System used by the Energy Information Administration, and the Integrated Planning Model developed by ICF Consulting and used by the U.S. Environmental Protection Agency (EPA). In the present study, Haiku simulates the scenarios of renewables policy and interregional transmission capability expansion described in the previous section.

4.1 Model Overview

The Haiku model simulates equilibrium in regional electricity markets and interregional electricity trade with an integrated algorithm for emission control technology choices for SO_2, NO_x, and mercury. The composition of electricity supply is calculated using a fully integrated algorithm for capacity planning and retirement, coupled with system operation in temporally and

[10] The Haiku model has been used to develop the analysis in numerous peer-reviewed articles and reports. The documentation of the Haiku model is Paul and Burtraw 2002. A new edition of the Haiku documentation will be forthcoming in 2008. Previously, the model has been compared with other simulation models as part of two series of meetings of Standord University’s Energy Modeling Forum (EMF 1998, 2001).

geographically linked electricity markets. The model solves for electricity market equilibrium in 20 Haiku market regions for the continental United States (see Figure 2 above).

Each year is subdivided into three seasons (summer, winter, and spring-fall) and each season into four time blocks (superpeak, peak, shoulder, and base). For each time block, demand is modeled for three customer classes (residential, industrial, and commercial). Supply is represented using model plants that are aggregated according to their technology and fuel source from the complete set of commercial electricity generation plants in the country. Investment in new generation capacity and the retirement of existing facilities is determined endogenously in a dynamic framework, based on capacity-related costs of providing service in the future ("going forward costs"). Operation of the electricity system (generator dispatch) in the model is based on the minimization of short-run variable costs of generation.

Equilibrium in interregional power trading is identified as the level of trading necessary to equilibrate regional marginal generation costs net of transmission costs and power losses. These interregional transactions are constrained by the level of the available interregional transmission capability as reported by the North American Electric Reliability Council (2003a, 2003b).[11] Factor prices, such as the cost of capital and labor, are held constant. Fuel prices are benchmarked to the forecasts of the Annual Energy Outlook 2007 for both level and elasticity (EIA 2007a). Coal is differentiated along several dimensions, including fuel quality and content and location of supply; and both coal and natural gas prices are differentiated by point of delivery. The price of biomass fuel also varies by region depending on the mix of biomass types available and delivery costs. Other fuel prices are specified exogenously.

Emissions caps in the Haiku model, such as the Title IV cap on national SO_2 emissions, EPA's Clean Air Interstate Rule caps on eastern regional emissions of SO_2 and NO_x, and the Regional Greenhouse Gas Initiative (RGGI) cap on CO_2 emissions, are imposed as linear constraints on the sum of emissions across all covered generation sources. Emissions of CO_2

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

from individual sources depend on emission rates, which vary by type of fuel and technology, and total fuel use at the facility. The sum of these emissions across all sources must be no greater than the allowances available, including those issued for the current year and any unused allowances from previous years. Unused emissions allowances that can be banked for use in the future are supported by Haiku. To determine the rate at which the size of the allowance bank changes, the model imposes a Hotelling constraint that the rate of change in the price of emissions allowances must be no greater than the interest rate.

4.2 Baseline Model Configuration

All the modeling scenarios presented in this paper are identically configured along many dimensions, including simulation years, regional electricity market regulations, environmental policies, and a few selected policies directed at renewables. The only variations from the baseline configuration specifications described here are those specifically mentioned in the scenario descriptions.

Each scenario is solved for four future years: 2010, 2015, 2020, and 2025. Electricity markets are assumed to maintain their current regulatory status throughout the modeling horizon; that is, regions that have already moved to market-based pricing of generation continue that practice, and those that have not made that move remain regulated. Figure 2 in Section 3 indicates the electricity pricing regime imposed upon each HMR. The price of electricity to consumers does not vary by time of day in any region, though all customers in competitive regions face prices that vary from season to season.

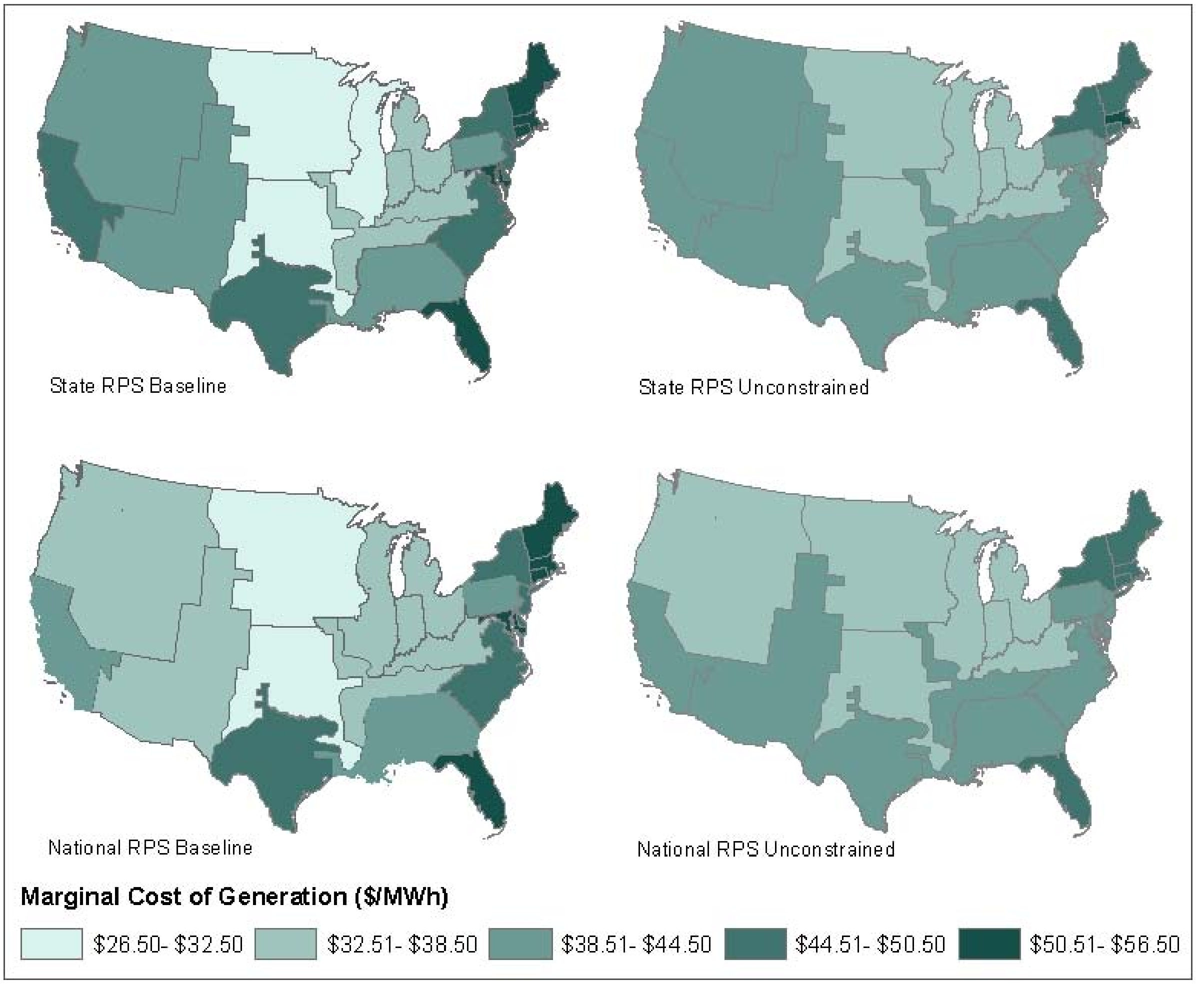
Emission allowances for SO_2, NO_x, and mercury are allocated to generators based on historical measures (grandfathering schemes). The exception is RGGI CO_2 allowances, which are distributed in allowance auctions. Allowances are bankable under all the allowance trading programs but cannot be borrowed. Any scenario that includes a renewable portfolio standard does not include a safety valve or cap on the price of renewable energy credits. All scenarios include a renewable energy production credit for generators in Maryland. This policy pays new wind, geothermal, landfill gas, and dedicated biomass plants $8.50/Mwh; cofired biomass receives $5/MWh. There is also a federally funded investment tax credit worth 10 percent of the overnight capital costs to new geothermal capacity. This investment tax credit and the current Energy Policy Act 2005 version of the federal renewable energy production tax credit cannot both be claimed by any generator. For geothermal plants, the production tax credit will always be more valuable. Haiku therefore gives the investment tax credit to geothermal plants only in the absence of a production tax credit. For the reasons outlined in the previous section, the federal renewable energy production tax credit is not included in the baseline scenario.

5. Results

Based on the policy and technology scenarios described in Section 3, Haiku simulated four scenarios set along two dimensions: level of RPS (state or national) and level of interregional transmission expansion (baseline or unconstrained). The first scenario is the State RPS Baseline scenario, which represents a business-as-usual scenario in which the current state RPS policies are in force and no additional RPS at the national level is in place. The second scenario is the National RPS Baseline scenario, which assumes that all current state-level RPS policies remain in place with a 20 percent national RPS also in force by 2025. The last two scenarios correspond to incremental transmission expansions, as described in Section 3, for the State and National RPS scenarios. These scenarios are called the Unconstrained State RPS and Unconstrained National RPS because in each the transmission grid is expanded to alleviate all interregional power transmission congestion, as it is defined in Section 3.

Three major results emerge from the analysis of those four scenarios. First, the geographic distribution of generation resources in the western states and the locations of expected load center expansion in those areas will lead to a distribution of generators and customers that will exacerbate transmission congestion problems between northern California and its neighbors. Second, national RPS policy will bring expansion of wind power generation capacity to the central and northern plains states and exacerbate transmission congestion between these states and the Southeast. Third, failure to expand the capability of the southeastern states to import wind power from the Plains states will result in more biomass capacity construction in the Southeast to replace the inaccessible wind power from the Plains and to meet the national RPS target for renewable generation. These three results are described in detail in the following subsections.

Figure 3. Scenario maps of long-run marginal generation costs ($/MWh) by Haiku market region.



Figures 3 illustrates the driver of the interregional transmission expansion scenarios. If the grid was large enough to alleviate all interregional congestion, then the marginal generation cost of power generation would be equivalent across the country, net of transmission costs and losses. This effect is evident in the comparison of the two maps on the left with those on the right. No matter the renewables policy, transmission expansion tends to equilibrate marginal generation costs. Comparing the two maps on the top with those on the bottom reveals that national RPS policy tends to lower prices in the West. This effect is more pronounced for the baseline scenarios, in which transmission constraints prevent some power exports toward the East. In the National RPS Unconstrained scenarios these exports cause higher demand for western electricity, thereby raising marginal generation costs in those regions. These marginal cost values are long-run marginal costs, including the marginal capacity value associated with each MWh of generation.

Figure 4 shows, for selected regional pairs, the projected gross electricity trade between the pairs in 2020. For all of the selected regional boundaries, the direction of flow does not vary across scenarios. Therefore only one directional indicator, the arrow on top of the colored bars, is required and it applies to all four scenarios. The figure indicates that no matter the scenario for transmission capacity or renewables policy, power will flow toward the coasts. Another conclusion that can be drawn from this figure is that state vs. federal renewables policy has a larger impact on regional power flows when transmission capacity is greater. This is evident by comparing the differences between the dark blue and green columns with the differences between the light blue and yellow columns. The significance of this observation is that the grid configuration that would decongest the grid under state RPSs in 2020 would be quite unlike the configuration that would decongest the grid under a unified national RPS.

Figure 4. Gross interregional electricity trading (BkWh) between selected pairs of Haiku market regions, 2020

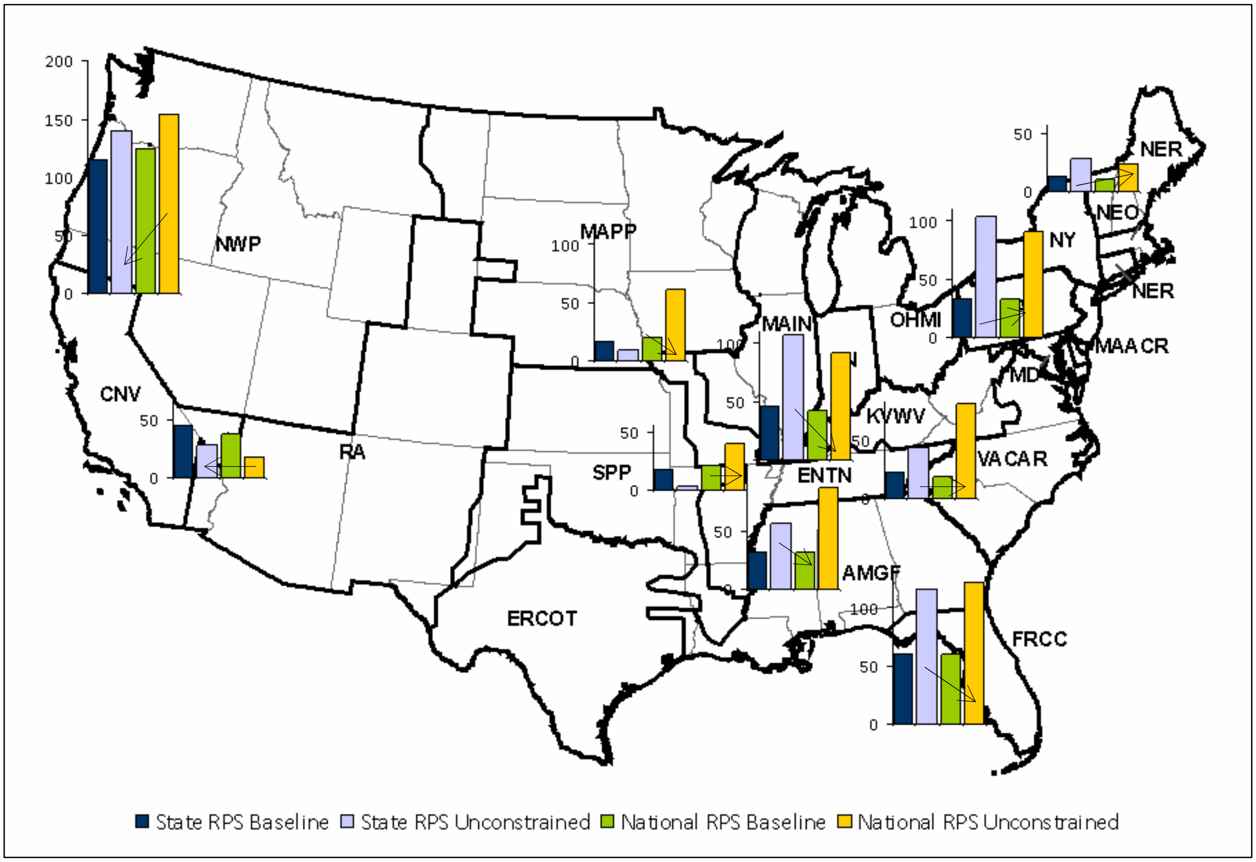


Table 2 is a national summary of the results of the four modeling scenarios in 2020 in terms of electricity prices and demand, generation, and capacity by fuel type, emissions, REC prices, fuel prices, and marginal generation costs. The table shows that moving from a state RPS policy regime to a national RPS policy regime leads to a small increase in the national average electricity price but a small decrease in the national average marginal cost of electricity generation. This effect occurs for both the baseline and the unconstrained transmission capability scenarios. The increase in electricity price results largely from the inevitable increase in average generation cost associated with the greater stringency of the national RPS scenarios. In the cost-of-service regulation parts of the country, increased average generation cost translates directly into increased electricity prices. The decrease in marginal generation cost is not inevitable in increased RPS stringency, as mentioned in Section 3, but has been realized in these scenarios.

Table 2 also shows that an expansion of the capacity for interregional power transmission sufficient to eliminate all line congestion will result in an increase in national electricity generation and consumption along with a commensurate increase in CO_2 emissions under either RPS policy case. This increase in CO_2 emissions amounts to about 1.7 percent in the state RPS case and approximately 3.5 percent in the national RPS case. Expanding transmission capability enables increased power flows from regions with relatively low marginal generation cost to those with higher cost. Because coal is a low-cost fuel, the regions that rely heavily on coal for electricity generation tend to have relatively low marginal generation costs and therefore export more power as transmission capability expands. The emissions from this increase in coal generation offsets the emissions reductions from other types of fossil fuel generators.

Table 2. Electricity demand, generation, and capacity by fuel type and emissions, REC prices, fuel prices, and marginal generation costs, for four scenarios, 2020.

	State RPS Baseline	Unconstrained State RPS	National RPS Baseline	Unconstrained National RPS
Electricity demand (BkWh)	4,636	4,659	4,621	4,643
Electricity generation (BkWh)				
Coal	2,296	2,331	2,119	2,201
Natural gas	869	857	802	794
Oil	63.7	62.0	61.0	60.5
Nuclear	927	907	886	841
Wind	235	270	372	432
Biomass	86.9	82.4	216	162
Geothermal	84.8	84.7	84.8	84.9
Landfill gas	16.7	12.6	20.3	18.0
Solar	0.8	0.8	0.8	0.8
Qualifies for national REC	424	450	693	697
Hydro	312	312	312	312
Total	4,914	4,942	4,897	4,928
Generation capacity (GW)				
Coal	350	343	332	331
Natural gas	454	449	427	433
Oil	50.4	53.3	50.3	48.1
Nuclear	125	124	120	115
Wind	65.6	75.6	105	121
Biomass	18.7	17.7	42.6	33.3
Geothermal	12.2	12.2	12.2	12.2
Solar	2.3	1.8	2.9	2.5
Landfill gas	0.4	0.4	0.4	0.4
Hydro	99	108	163	170
Qualifies for national REC	94.9	94.9	94.9	94.9
Total	1,171	1,170	1,180	1,186
Emissions (million tons)				
NO_x	2.4	2.4	2.3	2.4
SO_2	3.9	3.8	3.8	3.8
CO_2	3,016	3,069	2,802	2,901
Mercury (tons)	22.5	21.9	22.5	22.7
RPS	9.2%	9.7%	15.0%	15.0%
National REC price ($/MWh)	0.0	0.0	11.9	9.1
Electricity price ($/MWh)				
Residential	80.9	79.7	81.7	80.5
Commercial	64.8	63.8	65.6	64.4
Industrial	53.1	52.2	54.1	53.1
Customer class average	67.9	66.9	68.8	67.6
Marginal generation cost ($/MWh)	40.6	40.2	39.8	39.8
Fuel prices ($/MMBtu)				
Delivered coal	1.58	1.60	1.57	1.58
Delivered natural gas	5.49	5.43	5.40	5.34
Delivered oil	4.41	4.41	4.37	4.37

5.1 Power Flows Center on Northern California

California currently imports power from its neighbors and is expected to continue to do so for the foreseeable future.[12] Table 3 shows projected interregional power trading between the three western regions. It is evident that power flows into California will outweigh all other interregional trading in the western states and that the majority of power imported by California will come from the Pacific Northwest, no matter whether a national RPS is in place or the transmission grid is expanded to alleviate congestion. Furthermore, the enactment of a national RPS will increase the flow of power on the lines to California from the north and east while decreasing the flow on the lines to California from the Southwest. An expansion of the transmission grid nationwide would further increase the power flowing on the lines into California from the Pacific Northwest while simultaneously reducing the flow on the lines into California from the Southwest. These results suggest that interregional transmission capacity between California and the Pacific Northwest should receive priority in siting integrated energy corridors or dedicated transmission corridors.

Although the bulk of the load centers in California are located toward the south of the state, most of the out-of-state generators selling power into California markets are to the north and northeast. The location of economical electricity generation sources drives the baseline result that California will import the majority of its power from the Pacific Northwest (Table 3). This is also the driver of the increased power flow from the Pacific Northwest and the decreased flow from the Southwest under grid decongestion in the absence of a unified national RPS policy. The portfolio of economical renewable resources in the Pacific Northwest is more abundant than that in the Southwest. This difference is the driver of the increase in Pacific Northwest exports and decrease in Southwest exports under a national RPS in the absence of grid expansion. Since the national RPS scenario alone and baseline grid expansion alone lead to the same outcome (in sign, not magnitude), it is expected that the pairing of a national RPS and grid expansion would lead to the greatest flow of power from the Pacific Northwest and smallest from the Southwest.

[12] For clarity, the acronyms for model regions are replaced by common names in the following sections. CNV is referred to as California, NWP is referred to as the Pacific Northwest, and RA is referred to as the Southwest.

Table 3. Projected power trading (BkWh) between western regions, 2020

Importer	*Exporter*	*State RPS Baseline*	*Unconstrained State RPS*	*National RPS Baseline*	*Unconstrained National RPS*
California	Pacific Northwest	115.1	140.6	124.8	153.7
California	Southwest	44.7	28.1	37.3	18.0
Pacific Northwest	California	1.6	1.6	1.6	1.6
Pacific Northwest	Southwest	3.0	3.0	3.0	3.0
Southwest	California	0.0	0.0	0.0	0.0
Southwest	Pacific Northwest	5.3	1.4	5.8	5.9

5.2 Western Renewables Expand and Power Flows East

The enactment of a national RPS policy will lead to a substantial increase in renewable generation capacity. Table 4 shows the amount of new renewable capacity that is projected by the Haiku model for the four scenarios. These data have been aggregated from Haiku market regions to a more aggregate set of five regions.[13] Regardless of the configuration of the interregional transmission grid, the national RPS policy is projected to result in the addition of more than 50 GW of renewable capacity by 2020. These additions will be concentrated west of the Mississippi, given the higher concentration of cheaper renewables in that area, with also some additions in the southeast. Figures 5 and 6 provide another view of this capacity expansion with capacity additions decomposed into conventional technologies and three types of renewable technologies.

Table 4. Projected new renewable generation capacity (GW) by aggregate region, 2020

Region	*State RPS Baseline*	*Unconstrained State RPS*	*National RPS Baseline*	*Unconstrained National RPS*
RGGI	14.1	13.5	15.7	14.7
Rockies and West	38.6	41.4	59.2	64.5
Big 10 and Appalachia	4.8	4.7	5.5	5.3
Southeast	2.2	1.9	14.2	8.1
Plains	18.3	24.7	37.2	47.5
National	77.9	86.1	131.9	140.1

[13] Big 10 is a moniker refering roughly to the region covered by the NCAA conference called the Big 10.

Figure 5. Composition of generation capacity under state RPS baseline scenario, 2020

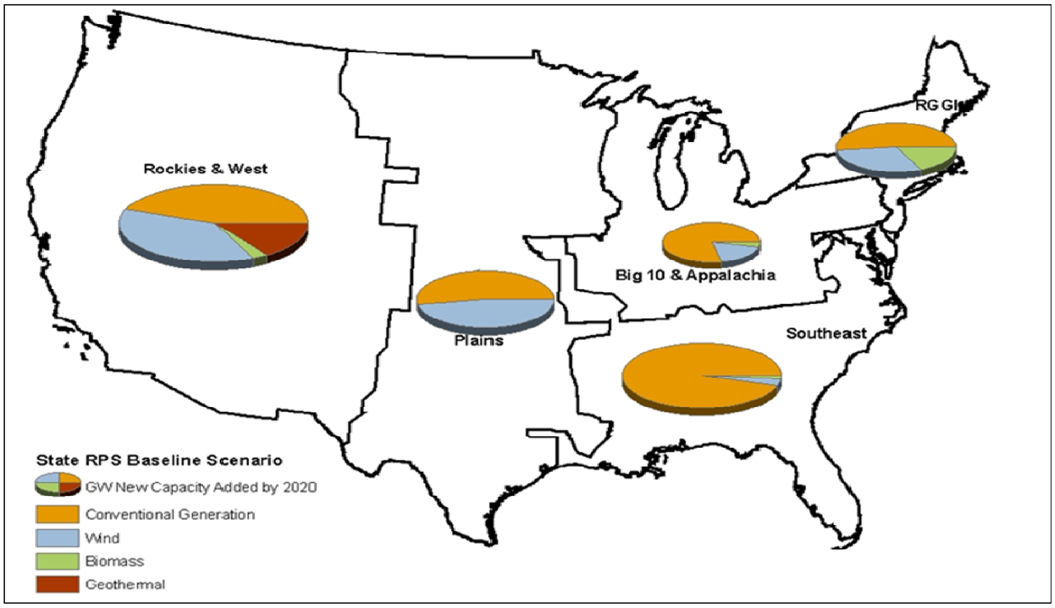


Figure 6. Composition of generation capacity under national RPS baseline scenario, 2020

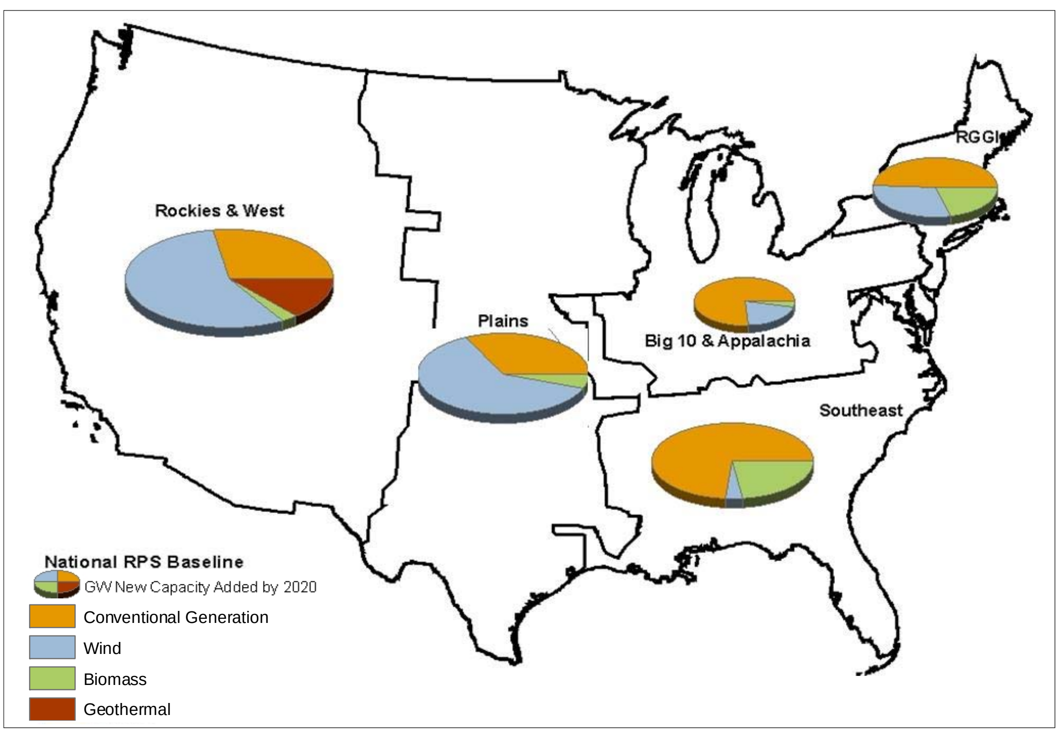


Table 5 reveals that transmission congestion would be exacerbated by a national RPS. Consider the difference between the baseline and unconstrained columns for each RPS scenario as a measure of excess demand for interregional transmission transfers. For the Southeast, excess demand for power imports would be about 24 BkWh without a national RPS policy but would rise almost four times, to nearly 100 BkWh, under a national RPS policy. A similar pattern emerges for the Plains states, where demand would actually fall under grid expansion in the absence of a national RPS, but excess demand for electricity exports from the Plains states would rise to almost 40 BkWh if a national RPS policy were enacted. For these two regions, transmission congestion will clearly be made worse by a national RPS policy in the absence of grid expansion above and beyond the baseline scenario. Other regions will experience smaller changes in excess demand as a result of a national RPS policy.

Table 5. Projected net power exports (BkWh) by aggregate region, 2020

Region	*State RPS Baseline*	*Unconstrained State RPS*	*National RPS Baseline*	*Unconstrained National RPS*
RGGI	–124.2	–178.9	–119.7	–167.4
Rockies and West	–11.9	–29.8	–10.9	–9.5
Big 10 and Appalachia	158.7	280.8	145.5	254.2
Southeast	–89.7	–114.0	–89.3	–187.5
Plains	57.6	33.0	64.7	102.2

How are these regional power flows manifest in regional power generation? The bottom row of Table 6 indicates that interregional transmission constraints leave approximately 30 BkWh of electricity generation unrealized no matter the renewables policy, and that a national RPS would reduce national power generation by around 15 BkWh no matter the level of the transmission grid. So the simultaneous imposition of transmission expansion and national RPS policy would expand generation by about 15 BkWh nationwide, but this power would not be evenly distributed. Instead, the regional differences suggested by Table 5 are realized in Table 6, with the Unconstrained National RPS scenario yielding more generation than the State RPS Baseline scenario in the Plains and the Big 10 and Appalachia states. The Southeast and RGGI states will experience the opposite outcome but with smaller aggregate magnitude.

Table 6. Projected electricity generation (BkWh) by aggregate region, 2020

Region	*State RPS Baseline*	*Unconstrained State RPS*	*National RPS Baseline*	*Unconstrained National RPS*
RGGI	437	395	445	406
Rockies and West	873	854	872	875
Big 10 and Appalachia	1,357	1,475	1,341	1,446
Southeast	1,342	1,324	1,332	1,242
Plains	905	894	906	958
National	4,914	4,942	4,897	4,928

5.3 Grid Expansion Shifts Southeastern Biomass to Western Wind

Table 4 showed that the level of interregional transmission capacity sufficient to alleviate interregional congestion under the national RPS scenario would lead to about 15 GW of new renewable capacity moving into the western states (10 GW in the Plains states and 5 GW elsewhere in the West) while 6 GW of new renewable capacity would move out of the Southeast. This shift is from biomass capacity in the Southeast to wind capacity in the West, as revealed by Tables 7 and 8.

To date, some of the strongest opposition to a national RPS has come from the southeastern states, which have argued that the Southeast is disadvantaged by a lack of native renewable resource potential. Our analysis reveals that resource potential alone does not drive renewables penetration under a national RPS. Interregional transmission access and capacity are also important factors in determining which renewable resources are used for new generation and at what marginal cost. As one would expect, REC prices come down with transmission expansion, making the policy more affordable for consumers everywhere. On the other hand, many states with RPSs identify local economic development as one of the main goals of the standard. Figure 6 indicates that a national RPS under business-as-usual transmission expansion could provide new opportunities for intraregional economic development in the Southeast that would not otherwise be available after a more ambitious grid expansion.

Table 7. Projected new wind generation capacity (GW) by aggregate region, 2020

Region	*State RPS Baseline*	*Unconstrained State RPS*	*National RPS Baseline*	*Unconstrained National RPS*
RGGI	9.2	8.5	9.3	9.3
Rockies and West	27.2	30.5	47.7	53.1
Big 10 and Appalachia	3.4	3.7	4.0	3.8
Southeast	1.2	1.8	2.4	2.4
Plains	18.1	24.5	34.6	46.4
National	59.1	69.1	98.0	115.0

Table 8. Projected new biomass capacity (GW) by aggregate region, 2020

Region	*State RPS Baseline*	*Unconstrained State RPS*	*National RPS Baseline*	*Unconstrained National RPS*
RGGI	4.4	4.5	5.8	4.9
Rockies and West	2.3	1.6	2.2	2.2
Big 10 and Appalachia	0.5	0.5	0.6	0.6
Southeast	0.7	0.0	11.0	5.2
Plains	0.0	0.0	2.4	1.0
National	7.9	6.7	22.0	13.8

6. Conclusions and Policy Implications

This study highlights the complex relationships between interregional power transmission constraints and renewables policy. The results of the scenario comparisons presented here suggest that where federal agencies site new transmission corridors could have a significant impact on the locations of new renewable capacity. Conversely, policies that motivate different levels and locations of new renewable generation, such as state mandates and federal proposals for a renewable portfolio standard, could substantially affect the locations of interregional transmission congestion, which in part drives corridor prioritization. This strong interrelationship is important not only for the current western corridor locations, but more generally for future corridor designations. For these reasons, we believe it is important for decision-makers to take into account current and potential future renewables policies, above and beyond the locations of renewable resource potential, when identifying and prioritizing new energy corridors.

Our results suggest that whatever the policy aims, coordination between renewables and transmission policy is imperative if new measures are to be optimally effective on either front.

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