The Economic Effects of Interregional Trading of Renewable Energy Certificates in the U.S. WECC

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ABSTRACT

In the U.S., individual states enact Renewable Portfolio Standards (RPSs) for renewable electricity production with little coordination. Each state imposes restrictions on the amounts and locations of qualifying renewable generation. Using a co-optimization (transmission and generation) planning model, we quantify the long run economic benefits of allowing flexibility in the trading of Renewable Energy Credits (RECs) among the U.S. states belonging to the Western Electricity Coordinating Council (WECC). We characterize flexibility in terms of the amount and geographic eligibility of out-of-state RECs that can be used to meet a state's RPS goal. Although more trade would be expected to have economic benefits, neither the size of these benefits nor the effects of such trading on infrastructure investments, CO_2 emissions and energy prices have been previously quantified. We find that up to 90% of the economic benefits are captured if approximately 25% of unbundled RECs are allowed to be acquired from out of state. Furthermore, increasing REC trading flexibility does not necessarily result in either higher transmission investment costs or a substantial impact on CO_2 emissions. Finally, increasing REC trading flexibility decreases energy prices in some states and increases them elsewhere, while the WECC-wide average energy price decreases.

Keywords: Renewable Portfolio Standards, Renewable Energy Credits, Transmission planning, Western Electricity Coordinating Council, Electricity markets

http://dx.doi.org/10.5547/01956574.37.4.aper

1. INTRODUCTION

Climate change concerns have been instrumental in driving regulatory policies that seek to reduce emissions and promote increasing amounts of generation from renewable resources (Kung, 2012). Policies that explicitly promote production from renewable generation technologies include Renewable Portfolio Standards (RPS), Feed-in Tariffs (FITs), and Renewable Auction Mechanisms (RAMs) (Pérez de Arce and Sauma, 2016). Other environmental policies, such as carbon taxes or cap-and-trade programs, aim at reducing greenhouse gas emissions and do not specify renewable

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targets. However, emissions policies indirectly incent generation from renewable resources by making some conventional technologies less competitive (Fischer and Newell, 2008). This article focuses solely on the effects of varying RPS policy designs across several independent but neighboring jurisdictions.

An RPS is a market-based regulation that requires electric utilities and other load-serving entities (LSEs) within a region to supply a fraction of their energy from qualifying renewable resources within a compliance period. To date, 30 states in the U.S. have enacted binding renewable mandates while 7 others have created voluntary state renewable goals (US DSIRE, 2013). Some expectations for adopting these policies include reductions of in-state greenhouse gas emissions, improvement of competitiveness, diversification of fuel sources, job creation, and stabilization of electricity prices (Holt and Wiser, 2007). Although some observers have questioned whether RPS policies are the most cost-effective way to meet these economic and environmental objectives (Lyon and Yin, 2010), RPSs have been the most popular renewable policy in the U.S. for the last two decades (Wiser et al., 2007).

A distinctive feature of RPS policies is their flexibility. Most implementations allow LSEs to meet their renewable targets through ownership of an equivalent number of Renewable Energy Credits (RECs), which are financial instruments that represent the environmental attributes of electricity generated using renewable energy technologies. A REC is created from the generation of one megawatt-hour (MWh) of energy from an eligible resource and can be traded as a commodity, separately from the electricity itself (Barry, 2002). Through this certificate trading mechanism, LSEs that fall short of the minimum number of RECs required by the RPS can still meet the mandate by purchasing certificates from eligible LSEs that hold RECs in excess of their target (Elder, 2007; Cory and Swezey, 2007). The trading eligibility of the RECs from out-of-state LSEs varies from one state to another.

On one hand, virtually all states having RPS policies allow for unlimited use of out-of-state RECs provided that the underlying electricity is delivered into the state. These are called "bundled RECs" because they correspond to out-of-state RECs that require deliverability of the electricity into the state. A MWh is generally deemed delivered in Western Electricity Coordinating Council (WECC) if the power is moved by "dynamic transfer"[1] in which some generation or other resource in the receiving region is controlled so that it compensates for fluctuations in the output of the renewable source. This requires sophisticated communications and control systems, and results in varying and perhaps inefficient use of interties between the source and sink balancing authorities, in that intertie capacity with a positive shadow price in the day-ahead market might then go unused in real-time. The transaction costs involved in dynamic transfers therefore are a recognized barrier to importing bundled renewables, especially from distant balancing authorities, and policy makers have been considering methods to lower those costs (RAP, 2012; Coffee et al., 2013).

However, only some states allow for "unbundled RECs"; that is, out-of-state RECs that do not require deliverability into the state. By allowing utilities to meet a fraction of the RPS goal with out-of-state unbundled RECs, states aim to further reduce the expense of meeting the RPS regulation. Unbundled RECs allow LSEs to take advantage of the most cost-efficient renewable resources available for deployment, independent of location. Consistent with the tradeable RECs

1. Dynamic transfer refers to electronically transferring generation from the balancing authority area in which it physically resides to another balancing authority area in real-time. Such transfers allow generation to be located and controlled in a geographic location that is outside of the receiving balancing authority area.

approach, the European Union is currently studying the replacement of national renewable targets with an overall European goal after 2020 (Castle, 2014).

Although unbundled RECs have the advantage of allowing exploiting the most cost-efficient renewable resources available for deployment, each state has its own reasons to restrict the eligibility of out-of-state resources. Accordingly, it is important to acknowledge the policy objectives that have driven states to restrict eligibility of out-of-state resources, such as local economic development and reduction of local pollution. Furthermore, there are several legal challenges that have arisen with respect to these restrictive provisions (related to the commerce clause of the U.S. constitution, for example). In summary, there are several issues that states must weigh, beyond just the economic impacts, when considering how to implement their RPS policies.

On the other hand, empirical and theoretical studies have found that RECs and other sources of flexibility in emissions policies may have unintended consequences on electricity markets and the environment (Bushnell et al., 2008). For example, a lack of coherence in the geographic scope of regional electricity markets and cap-and-trade programs can result in short-run displacement of CO_2 emissions from a capped region to uncapped regions, which could increase aggregate emissions (Chen, 2009; Sauma, 2012). It has also been shown that firms that own efficient generation technologies have economic incentives to withhold emissions permits to increase their market share in the electricity market (Limpaitoon et al., 2014). Yet, little research has been conducted on the economic effects of RPS designs that incorporate flexible REC trading schemes, and the few existing studies are mostly qualitative.

Mozumder and Marathe (2004), for instance, describe the benefits and challenges of integrated REC markets in Australia and Europe. Meanwhile, in the U.S., Mack et al. (2011) discuss limitations that some states impose on LSEs regarding RECs obtained from other states. They conclude that limiting the geographical eligibility of RECs leads to both more volatile and less liquid markets for RECs. Berendt (2006) and Sovacool (2011) reach a similar conclusion and propose a national trading platform for renewable certificates that would deepen REC market liquidity. All of the foregoing studies disregard the effects that transmission congestion and costs may have on the outcomes of the renewable policies. As noted by Kahn (2010), the cost of transmission needed to integrate renewables could be nearly four times the cost of ancillary services used to back up these generation technologies. In particular, the California Public Utilities Commission estimates that transmission investments required to meet the 33% state RPS by the year 2020 will cost approximately $16 billion, which is double the annual wholesale cost of electricity of the California ISO in 2011 (CPUC, 2009).

To the best of our knowledge, there are only three studies that have explicitly considered the interaction between the design of RPS policies and transmission infrastructure investment cost. Using an aggregated regional-based model of the U.S. electric power system, Vajjhala et al. (2008) evaluate the effects that state RPSs—or a hypothetical federal renewable mandate—would have on interregional power flows, as well as on transmission and generation investments needed to meet the targets. They find that a federal RPS would significantly change the geographical distribution of investments compared to a set of state targets that can be met only by in-state resources. Munoz et al. (2013a) utilize more detailed network models to analyze the impact of different RPS designs in transmission planning. They find that ignoring Kirchhoff's Voltage Laws (KVLs) or transmission investment indivisibilities can significantly bias investment portfolios for their hypothetical network. Munoz et al. (2013b) propose a stochastic investment-planning model that co-optimizes transmission and generation investment. They represent long-term market and regulatory uncertainties with different scenarios of state and federal environmental policies. As with Vajjhala et al. (2008), they conclude that federal and state regulations require distinct investment portfolios to meet the renewable targets at minimum cost for consumers. However, none of the previous studies quantify the economic and environmental effects of RPS designs that include flexible unbundled REC trading schemes.

As mentioned earlier, trading of RECs among regions to meet RPS targets might be expected to have a positive aggregate impact, but there is less certainty about the magnitude of the benefits and the effects of such trading on infrastructure investments, CO_2 emissions and energy prices. In this article we quantify the economic benefits of allowing increased trade of unbundled RECs among states in the WECC in order to meet their renewable targets.[2] We utilize a planning model that co-optimizes the portfolio of transmission and generation investments simultaneously. Our model accounts for realistic features that are often overlooked in high-level energy-economic models for policy analysis, including transmission investment indivisibilities, the variability of renewable resources, and parallel-flow effects due to Kirchhoff´s Laws.[3] Assuming projected state renewable targets, we study the impact of different degrees of REC trading flexibility upon the total system cost and infrastructure investments using a 240-bus network reduction of the WECC. We also measure the impacts of REC trading upon CO_2 emissions and average electricity prices, distinguishing between states that import RECs to meet their local renewable targets and states that export their surplus of certificates.

With our planning tool, we study the economic and redistributive effects of two different dimensions of policies concerning trading flexibility. The first dimension is the geographic eligibility of unbundled RECs produced out of state to meet each state's renewable target, which we approximate by defining four distinct configurations of trading regions within the U.S. states of the WECC. We assume that the transaction costs associated with flexible transfers of bundled power between balancing authorities, together with the existence of 38 balancing authorities in the WECC region, mean that transfers of bundled renewable power and certificates is relatively minor. The second dimension is the quantity of certificates that LSEs are allowed to purchase from out-of-state renewable generators. Our numerical simulations suggest that a large fraction of the economic benefits of inter-regional trading of certificates can be captured for relatively small amounts of trading flexibility, e.g., 25%. As we explain later on Section 5.1, this occurs due to the rapid exhaustion of the best-quality renewable resources when this amount of trading flexibility is allowed.

The rest of this paper is organized as follows. Section 2 presents a simplified two-region illustration of the fundamental benefits and costs associated with REC trading. Section 3 describes the transmission and generation expansion planning model we use to study the effects of unbundled certificate trading in the WECC region. Section 4 summarizes the main characteristics of the WECC 240-bus test-case and our methodology. Section 5 describes results from several different experiments with varying degrees of REC trading flexibility. Section 6 concludes the paper.

2. We analyze the WECC system mainly because the trading flexibility of RECs is a timely issue in the WECC and particularly in California. However, the methodology proposed to quantify the effects of unbundled REC trading on infrastructure investments, CO_2 emissions and energy prices is applicable to any region within the US and to other countries.

3. Kirchhoff's Laws are physical relationships among bus voltages and line currents that govern the flow of power throughout transmission networks. In the context of our model, the first law states that the sum of the net injections at every bus has to be equal to zero; the second law is that the sum of voltage differences around any loop in the network is zero. Their combined effect determines how power flows are distributed among parallel lines depending upon their physical characteristics. Ignoring the laws and flow limits on individual lines (e.g., the "copper-plate" assumption) in general result in lower operating costs than if they are explicitly accounted for on the dispatch of the system. However, dispatch schedules from models that disregard Kirchhoff's Laws are usually physically infeasible in practice.

2. THE ECONOMICS OF REC TRADING IN A TWO-STATE EXAMPLE

Consider a perfectly competitive market composed of two independent LSEs located in two different states: states 1 and 2, respectively. Each state has enacted an independent Renewable Portfolio Standard. State 1 requires its local LSE to prove that at least 30% of the electricity supplied to consumers is generated using renewable energy technologies, whereas state 2 has a less stringent renewable goal of only 20% for its LSE. The forecasted annual demand level for state 1 is 300 TWh/yr and 200 TWh/yr for state 2. For the sake of simplicity, let's assume that both LSEs have access to the same conventional generation technologies at long-run marginal cost $C(c) = 30 + 0.1c$ \$/MWh, where c is the conventional generation level in TWh. However, the availability and quality of renewable resources within each state—only wind and solar in this example—is quite different. State 1 has a limited amount of high quality wind resources near load centers and the existing grid. In addition, due to weather characteristics and land access issues, electricity supplied from solar resources in state 1 is significantly more expensive than in state 2 (e.g., rooftop PV in California vs. large-scale concentrated solar power in Arizona). State 2's wind resources are of poorer quality compared to wind in state 1, but still cheaper than the locally available solar resources. We assume that these characteristics are captured by the renewable resource supply curves (i.e., long-run marginal cost) $LC_1(r_1) = 70 + 1.1r_1$ and $LC_2(r_2) = 80 + 0.4r_2$ \$/MWh for states 1 and 2, respectively. If the renewable generation levels r_1 and r_2 are provided in units of TWh, the supply curve functions return the long-run \$/MWh marginal cost of the renewable resources available in each state.

Now imagine that the two states are considering the possibility of creating an integrated market for renewable energy certificates to provide LSEs more flexibility to meet each state's RPS. They are certain that inter-state trade of RECs could reduce compliance costs, yet they question whether the cost savings could justify potential changes in local energy prices and emissions. Let's first assume that there is enough transmission capacity available between the two states so that there is no congestion that limits energy trade between them. If states 1 and 2 each does not allow LSEs to use any out-of-state resource to meet the local renewable targets, the least-cost solution for renewable generation is $r_1 = 90$ TWh ($= 0.3*300$) and $r_2 = 40$ TWh ($= 0.2*200$) (see scenario a.1 in Table 1). Note that this scenario is more restrictive than actual RPS rules since it does not allow the trade of unbundled or bundled RECs (i.e., it does not allow out-of-state resources, even with physical delivery of the electricity). At those levels, the marginal cost of supplying renewables in each state differs (equal to \$169/MWh in state 1, and \$96/MWh in state 2).

On the other hand, since transmission capacity is unconstrained, the LSEs set conventional generation levels such that their marginal costs are equal (i.e., $C(c_1) = C(c_2)$), and therefore $c_1 = c_2 = 185$ TWh, with a marginal cost of \$48.5/MWh. Energy prices in the two markets, equal to $p_1 = 84.7$ and $p_2 = 58.0$ \$/MWh, respectively, reflect the impact of an additional unit of demand on both conventional and renewable generation costs (e.g., $p_1 = (1-0.3)C(185) + 0.3LC_1(90) = 84.7$). Renewable certificate prices, equal to $REC_1 = 120.5$ and $REC_2 = 47.5$ \$/MWh, are equivalent to the marginal cost of supplying an additional unit of electricity from renewable resources minus the cost of a displaced unit of power from conventional generation technologies (e.g., $REC_1 = LC_1(90) - C(185) = 169 - 48.5 = 120.5$). In this scenario, the price differential of RECs is the result of distinct renewable resource qualities and quantities used, since both LSEs select the same conventional generation levels.

Alternatively, if LSEs are allowed to use some out-of-state resources to meet the local renewable targets (see scenario a.2 in Table 1), the most economical levels of conventional and

Table 1: Results for Different Trading Schemes and Transmission Costs in the Two-state Example

Scenarios	Transmission Cost \$M/TWh	Conventional Generation TWh		Renewable Generation TWh		Fraction of Renewables		Exports 2→1 TWh	Electricity Prices \$/MWh		REC Prices \$/MWh		Total Cost \$M
		1	2	1	2	1	2		1	2	1	2	
a.1 No out-of-state REC	0	185.0	185.0	90.0	40.0	30.0%	20.0%	25	84.7	58.0	120.5	47.5	28,797.5
a.2 Out-of-state RECs allowed	0	185.0	185.0	41.3	88.7	13.8%	44.3%	73.7	68.6	61.9	---66.9---		27,021.2
b.1 No out-of-state REC	3.13	200.6	169.4	90.0	40.0	30.0%	20.0%	9.4	85.7	56.8	118.9	49.1	28,851.0
b.2 Out-of-state RECs allowed	3.13	200.6	169.4	43.4	86.6	14.5%	43.3%	56	70.4	60.5	---67.7---		27,223.8
c.1 No renewable power or REC exchange	Infinite	210.0	160.0	90.0	40.0	30.0%	20.0%	0	86.4	56.0	118.0	50	28,860.0
c.2 Unbundled RECs only	Infinite	250.0	120.0	50.0	60.0	16.7%	30.0%	0	76.0	56.0	---70.0---		27,500.0

Notes: Case (a) is unlimited transmission, (b) is limited transmission, and (c) is transmission limit equal to zero.

renewable generation are such that all the incentives for arbitrage of renewable certificates between states are eliminated (i.e., $LC_1(r_1) - C(c_1) = LC_1(r_2) - C(c_2)$). In this scenario we are assuming that either bundled or unbundled RECs can be acquired by LSEs without any transaction cost.[4] The resulting solution is $c_1 = 185$, $r_1 = 41.3$, $c_2 = 185$, and $r_2 = 88.7$ TWh with a unique REC price of 66.9 \$/MWh. As shown in Table 1, allowing out-of-state RECs reduces cost by 6.2% compared to the scenario that prohibits RPS compliance using out-of-state resources; these savings stem from more efficient use of the available renewable resources in both states. The displacement of renewable generation from state 1 to state 2 also affects regional energy prices. In this case, allowing out-of-state RECs causes the electricity price to fall by 18.9% (84.7 to 68.6 \$/MWh) in state 1, but to increase by 6.7% in state 2 (58.0 to 61.9 \$/MWh). As the location and amounts of conventional generation are unaffected by these changes with respect to scenario a.1, greenhouse gas emissions per state remain unchanged.

Now let's assume that the existing transmission infrastructure linking states 1 and 2 is fully congested and that any exchange of power between states costs 3.13 \$M/TWh.[5] As shown in Table 1, this transmission cost reduces exports from state 2 to state 1 by 62.4% if no out-of-state RECs are allowed (scenarios a.1 vs. b.1) and by 24% if the LSEs are allowed to acquire out-of-state RECs (scenarios a.2 vs. b.2). This also leads to shrinkage of the economic savings from allowing out-of-state RECs from 6.2% (\$1,776M from scenario a.1 to a.2) to 5.6% (\$1,627 from scenario b.1 to b.2). Notice that total system costs for scenarios b.1 and b.2 increase by more than just the transmission costs (\$29.4M and \$175.3M in scenarios b.1 and b.2, respectively) compared to scenarios a.1 and a.2.

4. The model used in this paper does not allow one to tag and trace the flow of bilateral energy transactions from generators to loads. Accordingly, it is not possible to track what fraction of the state's RPS goal is met with bundled RECs and what part is fulfilled with unbundled certificates. In this sense, scenario a.2 may eventually represent a situation with no unbundled REC trading, but where only bundled deliveries of out-of-state RECs occur.

5. This transmission cost corresponds to the annualized investment cost of the Devers-Palo Verde N. 2 project in California and Arizona (1,200 MW, M\$600). To compute the cost per TWh/year, we assume that the project is paid over 50 years with a 5% interest rate.

Table 1 also summarizes the results for the case where exchange of power between the states is infeasible, although RECs might be traded (scenarios c.1 and c.2, in which transmission cost is infinite), which could be interpreted as the case of the California and New York electricity systems, for example, which are unconnected by transmission networks. In scenario c.2, only unbundled RECs may be acquired from out-of-state LSEs to meet RPS goals. As expected, this constraint on power exports further reduces the benefits of REC trading to 4.7% (savings of c.2 with respect to c.1). As in the previous examples where out-of-state renewables were allowed (scenarios a.2 and b.2), in scenario c.2, state 1 imports out-of-state RECs from state 2 to meet the local RPS. However, in this case, state 1 cannot take advantage of cheaper (on the margin) conventional generation in state 2, which results from state 2's comparatively lower demand level. Assuming that conventional generation has a constant CO_2 emissions rate per MWh, the free trading of unbundled RECs in scenario c.2 increases state 1's emissions by 19% with respect to scenario c.1, even though the total emissions across the two states is unchanged. Consequently, under this scenario of constraints, state 1 might not support an inter-state market of unbundled renewable certificates if minimizing local CO_2 emissions is a higher priority than the economic gains from trading—even though total emissions across the two states is unchanged (40 TWh of conventional generation are displaced from state 2 to state 1). On the other hand, if the two states had different emissions rates for conventional generation, free trade in RECs could either increase or decrease total emissions, depending on which state has the more polluting technology.

This simple example illustrates how transmission constraints/costs and the economic and environmental effects of allowing out-of-state RECs interact. However, estimating the effects of REC trading on real-world power systems is more complicated. For instance, capturing the true economic value of renewable energy technologies requires consideration of the hourly availability of resources and their correlation with load (Joskow, 2011). Transmission investments, on the other hand, are better represented using discrete instead of continuous alternatives. In meshed transmission systems, it is also important to take into account the externalities from parallel flows. The model we describe in the next section incorporates all of these important features.

3. WECC MODEL DESCRIPTION

We extend the transmission and generation investment-planning model proposed by Munoz et al. (2013b) to account for different trading configurations of RECs among states. We assume that markets are perfectly competitive and that renewable targets are met in the most cost-efficient manner. The market equilibrium is computed by minimizing total system cost, which is equal to the sum of annualized investment (AI) and operations costs (OP) for one year.[6] AI corresponds to the sum of the annualized transmission and generation investment costs (equation (2), below). OP includes the sum of generation costs, penalties for load curtailments, and fines for noncompliance of RPS policies (equation (3), below).

We represent transmission investments using binary variables, but use continuous variables for generation additions, under the assumption that they can be made in relatively small increments. Since power flows are approximated using a linearized DC formulation, we enforce Kirchhoff´s Voltage Laws for candidate lines using linear disjunctive constraints (Munoz et al., 2013b). The

6. We use the year 2022 which is far enough in the future so that both generation and transmission capital is variable. Nonetheless, to be strict enough in the RPS compliance, we use the RPS goals required for the year 2025 in each state belonging to the WECC.

variability of wind, solar, and hydro resources is modeled using hourly profiles from historical data. We solve the resulting mathematical program using a commercial mixed-integer linear solver. As in Munoz et al. (2013a), our investment-planning model could be also formulated as a dynamic problem, which would allow us to study the effects of load growth, the increment of RPS targets over time, and the banking of renewable certificates. However, modeling those features is not essential for understanding the fundamental effects of flexible geographical REC trading schemes, and so it is left for future research.

In this section we introduce some of the notation used to define the investment-planning model. The rest of the nomenclature is described in Appendix A. Generators can be dispatched at level $g_{k,h}$ MW with marginal cost MC_k \$/MWh. We denote transmission and generation investment variables as x_l (binary) and y_k MW, with annualized capital costs CX_l \$/yr and CY_k \$/MW/yr, respectively.[7] Forecasted load levels per bus and per hour are $D_{b,h}$ MW. We assume that a certain amount of load $r_{b,h}$ MW can be curtailed at cost $VOLL$ \$/MW. Power flows through transmission lines are denoted $f_{l,h}$ MW and phase angles $\theta_{p,h}$ radians. Renewable targets, RPS_i (fraction), are defined with respect to the annual demand consumption per state. Noncompliance with the state renewable targets is denoted n_i MWh/yr and penalized at cost NC \$/MWh.

The optimization problem is defined as follows:

$$Min \quad AI + OP \tag{1}$$

Subject to constraints:

$$AI = \sum_{l \in L_C} CX_l x_l + \sum_{k \in G_C} CY_k y_k \tag{2}$$

$$OP = \sum_{k \in G} \sum_{h \in H} MC_k \, g_{k,h} + \sum_{b \in B} \sum_{h \in H} VOLL \; r_{b,h} + \sum_{i \in R} NC \, n_i \tag{3}$$

$$\sum_{l \in L} \phi_{b,l} f_{l,h} + \sum_{k \in G_b} g_{k,h} + r_{b,h} = D_{b,h} \qquad \forall\, b,h \tag{4}$$

$$f_{l,h} = S_l(\theta_{b,h} - \theta_{p,h}) \qquad \forall (b,p) \in \Omega_l,\, l \in L_E, h \tag{5}$$

$$|f_{l,h} - S_l(\theta_{b,h} - \theta_{p,h})| \le M_l(1 - x_l) \qquad \forall (b,p) \in \Omega_l,\, l \in L_C, h \tag{6}$$

$$|f_{l,h}| \le \overline{F}_l \qquad \forall\, l \in L_E, h \tag{7}$$

$$|f_{l,h}| \le \overline{F}_l x_l \qquad \forall\, l \in L_C, h \tag{8}$$

$$g_{k,h} \le W_{k,h}(Y^0{}_k + y_k) \qquad \forall\, k,h \tag{9}$$

7. We annualize transmission and generation capital costs by multiplying these costs by factors $\dfrac{\delta}{1-\dfrac{1}{(1+\delta)^{T_l}}}$ and $\dfrac{\delta}{1-\dfrac{1}{(1+\delta)^{T_k}}}$, with lifetimes T_l and T_k [yr], respectively. The parameter δ denotes the annual discount rate.

$$y_k \leq \bar{Y}_k \qquad \forall k \qquad (10)$$

$$\sum_{k \in G_{NI} \cap G_j} (Y^0{}_k + y_k) + \sum_{k \in G_I \cap G_j} ELCC_k (Y^0{}_k + y_k) \;\; \geq (1 + RM_j) \sum_{b \in B_j} D_{b,h} \qquad \forall j \qquad (11)$$

$$\sum_{l \in L} \Psi_{a,l} f_{l,h} \leq \overline{FG}_a \left[\sum_{l \in L_E} |\Psi_{a,l}| \overline{F}_l + \sum_{l \in L_C} |\Psi_{a,l}| \overline{F}_l x_l \right] \qquad \forall a,h \qquad (12)$$

$$\sum_{k \in G_R \cap G_i} \sum_{h \in H} g_{k,h} + n_i \geq \alpha * RPS_i \sum_{b \in B_i} \sum_{h \in H} D_{b,h} \qquad \forall i \qquad (13)$$

$$\sum_{i \in R_m} \sum_{k \in G_R \cap G_i} \sum_{h \in H} g_{k,h} + \sum_{i \in R_m} n_i \geq \left[\sum_{i \in R_m} RPS_i \sum_{b \in B_i} \sum_{h \in H} D_{b,h} \right] \qquad (14)$$

$$g_{k,h}, y_{k,}, n_i, r_{b,h} \geq 0 \qquad \forall k,b,h,i \qquad (15)$$

$$x_l \in \{0,1\} \qquad \forall l \qquad (16)$$

Equations (4) to (16) define the model constraints. Constraint (4) represents Kirchhoff´s Current Law, (5) and (6) impose Kirchhoff´s Voltage Law, (7) and (8) enforce line thermal limits, and (9) imposes maximum generation limits. The capacity of time-dependent generators (e.g., wind, solar, and hydro) is derated using hourly capacity factors from historical data ($W_{k,h}$, fraction). Constraint (10) defines generation build limits, (11) enforces installed reserve margins per state, and (12) imposes interface limits. We use constraints (13) and (14) to enforce each state's Renewable Portfolio Standard requirement and to define limits on the inter-state trading of RECs, respectively. Constraint (13) imposes the minimum in-state renewable generation requirement, which is defined through the parameter α as a fraction of the state renewable target. Equation (14) ensures that states that fall short of their nominal renewable goals can only purchase RECs from other eligible states that belong to a specified region.

4. TEST CASE AND METHODOLOGY

In this section we describe the main characteristics of the 240-bus representation of the WECC and our methodology to study the effects of different REC trading schemes among states. We use projections of 2022 demand and economic conditions, while imposing renewable targets that are based on policies that are planned for the middle of that decade.

4.1 Description of the WECC 240-Bus Test-Case

We use the 240-bus network reduction of the WECC originally proposed by Price and Goodin (2011) and later augmented by Munoz et al. (2013b), because this is the most detailed representation of the entire WECC that is publicly available. The system is composed of 240 buses, 140 generators (accounting for more than 200 GW), 448 transmission elements, 21 demand regions, and 28 flowgates. Wind generation variability is represented using 54 spatially aggregated hourly profiles from NREL's Western Wind Resources Database (NREL, 2012a). Similarly, solar intermittency is included in 29 regions with hourly profiles generated using NREL's PVWatts tool

Table 2: Projections of Demand in 2022 and Renewable Targets in 2025

State	AZ	CA	CO	ID	MT	NM	NV	OR	UT	WA	WY
Demand (TWh/year)	111.1	350.9	61.8	22.8	19.0	21.7	43.1	50	38.9	130.4	28.1
RPS average target (%)	8.8	33	22.8	-	9.7	15.6	22.1	21.8	-	12.1	-
RPS Demand (TWh/year)	9.8	115.8	14.1	-	1.8	3.4	9.5	10.9	-	16.6	-

Notes: Our model also considers demand in Mexico and Canada (Baja California, 21.5 TWh/yr; Alberta, 83.5 TWh/yr; and British Columbia: 76 TWh/yr). To compute the RPS average target in each state, we consider the specific RPS goal of each type of utility and then weight these RPS goals by the share of the utility in electricity consumption. For example, in the case of Colorado State, the RPS goals are set as 30% by 2020 for investor-owned utilities, 20% by 2020 for electric cooperatives serving 100,000 or more meters, 10% by 2020 for electric cooperatives serving fewer than 100,000 meters, and 10% by 2020 for municipal utilities serving more than 40,000 customers. The two IOUs in Colorado sold 62.8% of the electrical power to customers in Colorado in 2009. Sales by municipal utilities accounted for 15.4% of the total electricity sales in 2009. Sales by rural electric cooperatives accounted for 21.8% of the total electricity sales in the state in 2009. Assuming these percentages are kept in the future, that 50% of the electric cooperatives serve 100,000 or more meters, and that 50% of municipal utilities serve more than 40,000 customers, then the average Colorado State RPS target is computed as $30\% \cdot 62.8\% + 20\% \cdot 21.8\% \cdot 0.5 + 10\% \cdot 21.8\% \cdot 0.5 + 10\% \cdot 15.4\% \cdot 0.5 = 22.8\%$.

(NREL, 2012b). A more detailed description of the available renewable resources used in the model is presented in Appendix B. Appendix B includes the currently installed generation capacity by technology for each state (Table 3), the candidate generation capacity for new investments by technology by state (Table 4), some statistics (means, standard deviations, and correlations) for a sample of load, wind, and solar profiles (Table 5), and the location of solar and wind resources within the WECC (Figure 11). This information documents the quantity and quality of the resources in each state, which affects how much value they could bring into the system.

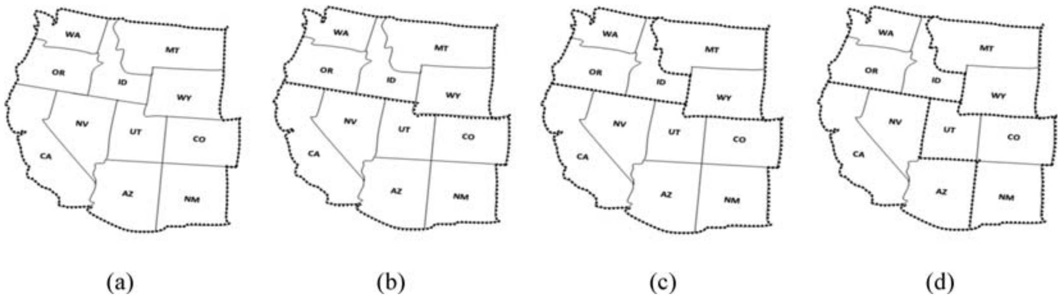
We do not allow the construction of new conventional coal power plants, large hydro power plants, or nuclear power plants; new thermal generation is assumed to be fueled by natural gas, biomass, or coal gasification. Candidate renewable resource locations that are far from the existing grid are grouped into 31 renewable hubs. We allow for the construction of up to four circuits of 500 kV to connect renewable hubs to the nearest high voltage buses and up to two parallel circuits of 500 kV to reinforce the transmission backbones. We consider a lifetime of 50 years for transmission investments, 40 years for coal power plant investments, 30 years for gas, biomass, and geothermal power plant investments, and 25 years for solar, wind and hydro power plant investments (U.S. Energy Information Administration, 2012). Demand for 2022 is projected from 2004 data assuming a constant growth factor per year (Munoz et al., 2013b). To capture the correlations of load and wind and solar output, we consider 10 individual hours h.

In the WECC representation, we include Baja California (Mexico), British Columbia and Alberta (Canada), and 11 U.S. states (Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming). Trading of RECs is allowed only among the states within the U.S. Although RPS goals vary in time, we used a static model that considers the RPS targets projected to year 2025 described in Table 2 (US DSIRE, 2013). As mentioned earlier, we limit our analyses to the effects of REC trading and ignore the possibility of year-to-year banking of certificates. We also disregard resource specific carve-out requirements imposed by some states, such as specific targets for solar.

4.2 Methodology and Experiments

Here we describe our methodology for quantifying the effects of different certificate trading schemes on total system cost, CO_2 emissions, average electricity prices per state, and REC prices. We study two dimensions of flexibility in REC use and trading schemes:

Figure 1: (a) 1-Region Scenario: No Geographic Restrictions. (b) 2-Regions Scenario. (c) 3-Regions Scenario. (d) 4-Regions Scenario



1. the amount of out-of-state RECs that can be used to meet in-state goals and
2. the geographic eligibility of out-of-state renewable resources.

We analyze the first feature by allowing states with enacted RPS policies to meet their mandates using up to 0%, 12.5%, 25%, 50%, 75% or 100% of out-of-state resources (either bundled or unbundled RECs) from states that belong to a delimited region, the latter defined using constraint (14). The fraction of out-of-state resources that each state is allowed to use in order to meet their renewable goal is limited by parameter α in constraint (13). We note that the case of allowing 0% of out-of-state RECs is a more restrictive case than the current RPS obligation because it does not allow any out-of-state RECs, even if they are delivered as a bundled product. This is equivalent to assuming that bundled products must be delivered by dynamic transfers, and that the transaction costs associated with such transfers are sufficiently high to discourage them.

We simulate the second aspect of REC flexibility—the geographic eligibility of RECs from out-of-state resources—by defining four distinct hypothetical configurations of interchange regions among the U.S. states in WECC (Figure 1). Although these four configurations are only a coarse approximation of the actual restrictions that states presently impose on the eligibility of out-of-state RECs, they allow us to systematically explore how geographical restrictions impact economic efficiency and emissions.

Some examples of these restrictions are the following. The state of Washington, for instance, allows LSEs to import renewable certificates from out-of-state renewable resources. In Washington, LSEs are allowed to import unbundled RECs from generators located in the Pacific Northwest and bundled RECs (requiring that the electricity is delivered to Washington State) from other states. California, as well as other states, requires a minimum percentage of the mandate to be met either by using in-state renewable resources or by using out-of-state renewable resources that are scheduled into the CAISO. Arizona, Colorado, Montana, New Mexico and Nevada, on the other hand, require 100% of in-state deliverability of generation from eligible renewable resources (Heeter and Bird, 2011). In our model, we do not consider all of these features and specifications of each state RPS in the WECC. Such simulation would require a much more complicated representation of the WECC market and the states' RPS designs. Rather, our experiments are intended to examine the general effects of different degrees of geographic restrictions.

We penalize noncompliance with renewable targets. Although our penalty of 500 $/MWh exceeds the noncompliance fines of most renewable mandates, it represents an upper bound on the marginal cost of supplying renewable power. The purpose of setting such a high noncompliance penalty in our simulations is to ensure that all the state renewable targets are met using the available renewable resources. The rationale behind this assumption is that, in practice, we expect that all RPS goals will be close to 100% fulfilled. If the penalties prove to be too small, we assume that policy makers will increase them such that noncompliance will be more costly than supplying the required amount of electricity from qualifying renewable resources or, depending on the RPS design, through the purchase of RECs from out-of-state generators.

In Section 5 we discuss the effects of lowering the noncompliance penalty from $500/MWh to $50/MWh, the latter of which is a lower bound for existing penalties in the WECC region. In that sensitivity analysis we show that noncompliance becomes a problem at that low level of penalty.

We also assume that all transmission investment costs are recovered through retail tariffs rather than surcharges in the bulk power market, which allows us to obtain marginal energy prices by fixing all binary variables in the model and re-solving the remaining linear program. The average energy prices reported in the next section correspond to the demand- and time-weighted nodal prices by state.[8] We also compute the average WECC-wide energy price as the demand-weighted average energy price. State and regional REC prices correspond to the dual variables associated with constraints (13) and (14), respectively.

All simulations were implemented using the AIMMS 3.13 algebraic modeling language and the CPLEX 12.4 solver on a computer with 4 cores and 4 GB of RAM. The model has 20,433 continuous variables, 510 binary variables, and 42,433 constraints.

5. RESULTS AND DISCUSSION

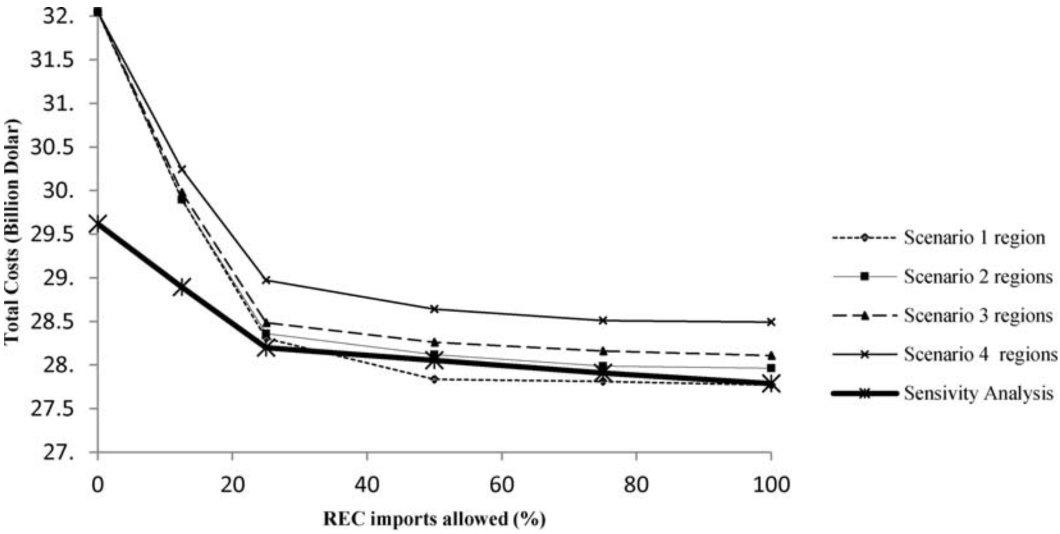
The following subsections summarize the results from our numerical experiments. We study how allowing out-of-state RECs affect total system cost, exports and imports of RECs by state, generation capacity investments, transmission investments, CO_2 emissions, and energy prices. In all the results presented in this section we do not make any distinction between unbundled RECs and bundled RECs. This means that, for instance, allowing for 50% of REC imports corresponds to the situation of allowing that half of the state's RPS goal can be met using either unbundled or bundled (or a combination of both) out-of-state RECs. Since unbundled RECs are more general (less restrictive since they do not require dynamic transfers), hereafter we will refer to REC trading flexibility as allowing unbundled RECs. We highlight results from the 1-Region scenario, since a federal or WECC-wide trading market is under discussion by policy makers.

5.1 Gains From Trade

Figure 2 illustrates the total system cost of the WECC (including both transmission and generation investment costs) for the four geographically-constrained scenarios and for different

8. Nodal energy prices are computed as: $\frac{d(O.F.)}{dD_{b,h}} = \sum_C \frac{\partial(RHS(C))}{\partial D_{b,h}} * \lambda_C$. These prices reflect changes in the objective function (O.F.) due to a 1-MWh variation in the load, which affects energy balance constraints, reserve margin requirement constraints, and RPS constraints. Thus, nodal prices correspond to the sum over all constraints (C) of the partial derivative of the right-hand side (RHS) of the constraints multiplied by the respective dual variables. To facilitate computation of a dual price that captures the effect of demand changes upon all of these constraints, it is possible to replace the parameter $D_{b,h}$ by the variable $d_{b,h}$ in equations (4), (11), (13) and (14). The prices at each bus and hour would then be given by the dual variable associated with the auxiliary constraint $d_{b,h} = D_{b,h}$.

Figure 2: Total Cost as a Function of Trading Flexibility



degrees of out-of-state REC flexibility, ranging from 0% to 100%. The 1-Region scenario with no restrictions on the amount of certificates traded (i.e., 100% unbundled REC trading) represents the most flexible design of RPS regulations in the WECC. This configuration allows states to meet their targets by taking advantage of the most cost-effective renewable resources in all regions. It therefore yields the lowest system costs of all experiments ($27.8 billion/yr, the point in the bottom right of Figure 2), and is 13.4% cheaper than the reference case, in which out-of-state RECs are not allowed ($32.0 billion/yr, the point in the top left of Figure 2). These cost savings of $4.28 billion annually are remarkably high—they approximately equal the total electricity revenues in the state of Oregon for the year 2012 ($3.83 billion) (U.S. EIA, 2014). However, it is worth remarking that the reference case (allowing 0% of out-of-state RECs) is a more restrictive case than the current RPS obligation because it does not allow any out-of-state RECs, even if they are delivered as a bundled product. States can, therefore, reduce the costs of meeting their RPS targets by expanding eligibility for unbundled RECs. Interestingly, most of the cost savings can be captured by allowing a relatively modest level of unbundled REC trading flexibility.

As shown in Figure 2, the first 25% of flexibility yields a cost reduction of approximately $3.7 billion/yr with respect to the reference case where no out-of-state RECs are allowed, as long as there are three or fewer trading regions. This is 90% of the cost savings that could be attained if states were allowed to use an unlimited amount of unbundled out-of-state resources to meet their local targets (100% unbundled REC trading allowed). Increasing the unbundled REC trading flexibility beyond 25% only marginally reduces cost further. For instance, doubling the amount of trading allowed from 25% to 50% would only reduce the total cost from $28.2 billion to $27.8 billion (under the 1-Region scenario).

There are two potential causes for this "knee" on the total system cost curve at 25% flexibility. First, the knee could reflect the depletion of high quality or cost-efficient renewable resources within WECC. Allowing further trading of unbundled RECs still allows states to reduce compliance costs, but with much less efficient renewable resources than the ones developed in the first 25% of trading. Second, as we increase unbundled REC trading flexibility, the system requires more transmission capacity (as compared with the reference case) in order to deliver power from renewable generators that are located in low demand areas or far from the existing grid. Thus, the savings of increased unbundled REC trading could be partially offset by additional transmission investment costs. Sensitivity analyses show that of the two possible causes, renewable resource quality—and not transmission cost—has the most significant impact on the total system cost.[9] We will analyze both generation and transmission investments in detail in the following subsections.

Figure 2 also illustrates the effect of restricting the geographical eligibility of out-of-state RECs to sub-regions of the WECC. As expected, constraining the exchange of RECs to the regions defined in scenarios 2, 3, and 4 reduces the efficiency of a WECC-wide integrated market of unbundled certificates (scenario 1). We find that the 2- and 3-Region configurations increase compliance cost by only 0.7% and 1.2% with respect to the most flexible policy design (scenario 1, 100% of unbundled REC trading allowed). However, the 4-Region configuration increases cost by 2.6%. This occurs because scenario 4 prevents California—the state with the highest demand and renewable target in the WECC—from taking advantage of renewable energy certificates that are created using low-cost and high-quality renewable resources from Utah and New Mexico. In contrast, in the 4-Region scenario, California will import unbundled RECs from the states of Nevada and Arizona, who in turn export a much lower amount of RECs under the other three scenarios. This occurs because solar and wind resources in Nevada and Arizona have a higher cost and lower economic value for the overall system relative to the ones available in the states of Utah, Colorado, and New Mexico.

In summary, trading unbundled RECs among states has positive effects on the WECC system cost. Although these are not general results, we find that a large fraction of the economic gains from trade are captured for a relatively small level of unbundled REC trading (25% in this case). Our numerical experiments also suggest that compliance costs are sensitive to the definition of geographical constraints that states place on the trading of certificates.

It is worth remarking that our simulations ignore the potential effects that an increase in the renewable generation, and its distribution between bundled and unbundled transactions may have on overall balancing costs. For trade of bundled power that is supported by dynamic transfers, these balancing costs may significantly increase in receiving states (given the evidence that the renewable energy forecasts are much less accurate than the load forecasts) when increasing bundled REC imports. Estimating the effects of increased trading of certificates on balancing costs would require a much more sophisticated model than the one used on this paper. Such model would need to account for the stochasticity of loads and renewable resources, as well as for the lack of coordination in the dispatch of resources across independent service areas. Therefore, it is possible that the magnitude of the cost reductions that result from increased trading of unbundled RECs may be smaller than what we predict in this section. However, such analysis is beyond the scope of this paper.

Figure 2 also shows a fifth scenario as a sensitivity analysis. This is an evaluation of the effects that the magnitude of the noncompliance penalty can have in the obtained results. This sensitivity analysis is equivalent to the 1-Region scenario, except for the use of a 50 $/MWh penalty instead of 500 $/MWh. For the 0% flexibility case, the total costs in the sensitivity analysis scenario are 7.6% lower than in the 1-Region scenario because noncompliance is cheaper than constructing large amounts of renewables in many states, such as California and Colorado. For example, California generates 79.7 TWh of renewable energy and pays a penalty for the remaining 115.8 TWh

9. We found that the knee in the total system cost curve does not change if all transmission constraints are relaxed. However, the knee disappeared if the generation capacity limits for renewables were removed from the constraints.

necessary to meet its RPS target. However, as RECs trading is increased, the amount of noncompliance is dramatically reduced. For 12.5%, 25% and 50% of unbundled REC imports allowed, noncompliance is reduced by 43%, 81% and 93%, respectively, relative to the 0% trading case. In the cases of 75% and 100% of REC trading flexibility, all states completely reach their goals without paying any penalty. Figure 2 shows that after 25% flexibility, the costs in the sensitivity analysis case are almost the same as in the 1-Region scenario.

5.2 Geographical Allocation of RECs

When unbundled REC trading is allowed, states that generate more renewable energy than the local RPS target are able to sell RECs to states that fall short of their targets. In contrast, when out-of-state resources are not allowed (0% flexibility), all states meet their RPS targets with in-state renewable generation. Figure 3 shows unbundled REC transactions for four different trading schemes. The sizes of the bars represent the magnitudes of the exports (white bars) or imports (dark bars) of unbundled RECs. The fraction of the state's demand that these exported or imported unbundled RECs represent is shown in Figure 3 as a percentage. For instance, in Figure 3b, the size of California's bar corresponds to 36.5 TWh per year of unbundled RECs imported, representing 10.4% of the state's demand.

We find that, in the 1-Region scenario (WECC-wide market of certificates), increasing the amount of allowed unbundled REC trading from 25% to 100% (Figures 3a and 3b) does not yield significant changes in the states that import and export certificates. Under both trading schemes, the states of Arizona, Idaho Nevada, New Mexico, Oregon, Utah, and Wyoming export RECs to California, Colorado and Washington. The exception is the state of Montana which becomes an exporter of RECs when the percentage of trading flexibility is increased from 25% to 100%. Note that Idaho, Utah and Wyoming have not enacted RPS targets (see Table 2), yet, they become exporters of RECs when their certificates are eligible to meet other state's renewable targets. Renewable resources are developed in these states as a consequence of the additional revenues generated from the exchange of unbundled certificates; they make some of the high quality renewable resources in Idaho, Utah, and Wyoming economically viable without the need for local regulatory incentives.

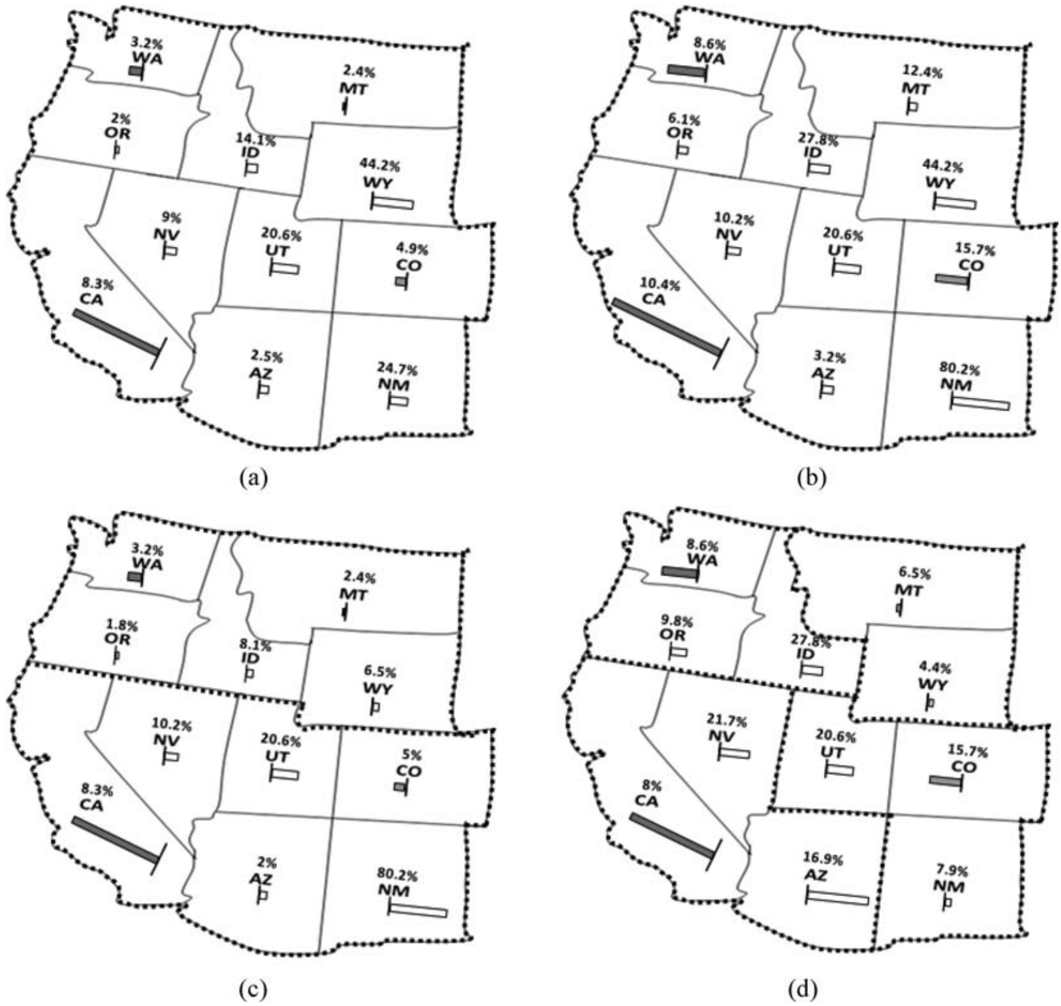
However, the amount of RECs that each state exports or imports is markedly affected by the geographic trading configurations. For example, in Figures 3a, 3b and 3c Arizona exports a low quantity of unbundled RECs. When the most stringent geographic restriction is imposed, Arizona exports a higher amount of RECs, which helps California reach its RPS target. In the other three scenarios, as there was no active geographical restriction, California imports more unbundled RECs from New Mexico.

5.3 Investments in Generation Capacity

Here we study the changes in the generation investments by technology as unbundled REC trading flexibility varies. Recall that following the new standards of the U.S. EPA, we do not allow the construction of new coal power plants without CCS technologies; nor are new large hydro and nuclear power plants allowed.

Figure 4 shows the distribution of costs of generation capacity investments by technology in the 1-Region scenario both in the case when no out-of-state resources are allowed (reference case, Figure 4a) and when 100% unbundled REC trading is allowed (Figure 4b). When full flexibility is allowed, generation investment costs decrease by 28% relative to the case without out-of-

Figure 3: Unbundled REC Exports (white bars) and Imports (dark bars)

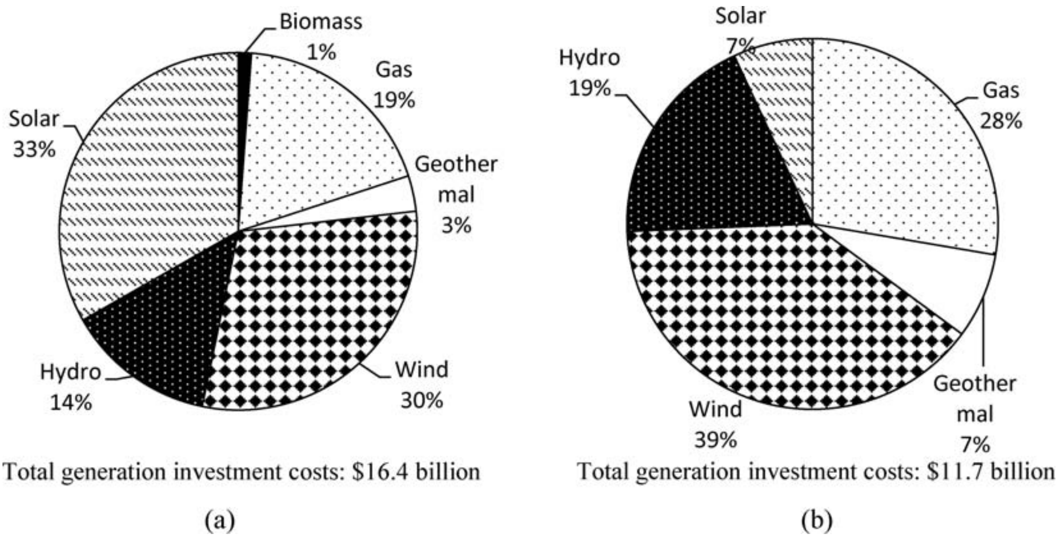


Notes: (a) 25% of REC trading is allowed in the 1-Region scenario, (b) 100% of REC trading is allowed in the 1-Region scenario, (c) 25% of REC trading is allowed in the 2-Region scenario, and (d) 25% of REC trading is allowed in the 4-Region scenario

state RECs. Note that no new coal power plants are built due to the high capital cost of coal power plants with CCS technologies. We find that a WECC-wide market for renewable certificates with flexible RPS policies would reduce the aggregate nameplate capacity of renewable energy technologies needed to meet state goals by approximately 3.1% with respect to the case without out-of-state RECs. This is a result of the flexibility imparted by RPS policies that permit 100% imports of unbundled RECs, which allows states to take advantage of the most cost effective renewable resources anywhere in the WECC, including states such as Idaho, Utah, and Wyoming that do not have RPS obligations.

Our numerical simulations suggest that inflexible state RPS policies (Figure 4a) result in much larger investments in solar generation, particularly in California. As shown in Figure 4a, solar represents 33% of the cost of generation capacity investments needed to meet state RPS policies,

Figure 4: Generation Investment Expenditures by Technology in the 1-Region Scenario, when (a) No Out-of-state RECs are Allowed, and (b) 100% REC Trading Flexibility is Allowed



as opposed to 7% in the scenario of flexible RPS policies (Figure 4b). In the latter, solar generation is replaced with cost-effective wind resources from New Mexico and Montana. Wind in these states is highly correlated with load and cheaper than solar on a per-MWh basis. Other generation sources, especially natural gas, increase their share of investment under the flexible policy.

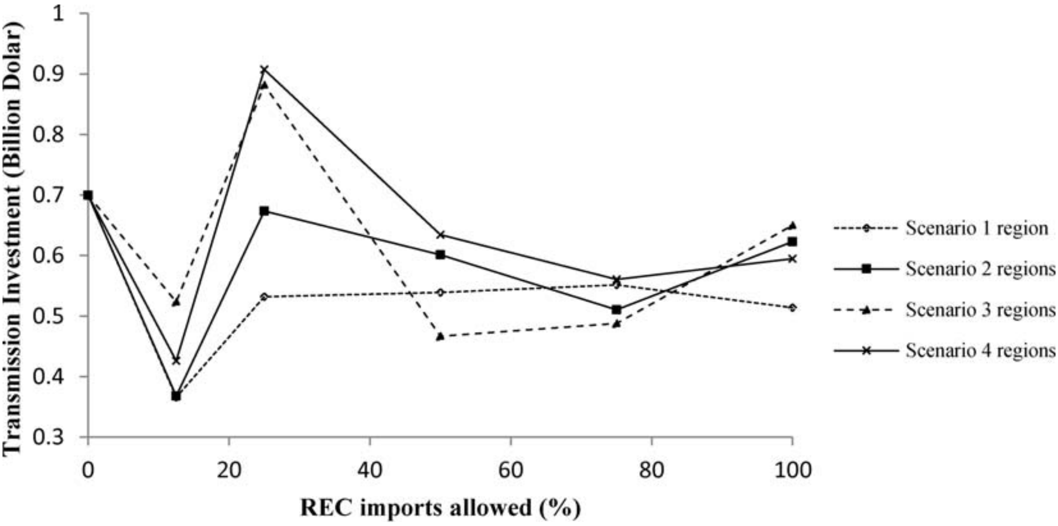
In the following subsections we analyze how unbundled REC trading affects transmission investments, CO_2 emissions and energy prices, focusing on the effects in three particular states that have different positions in the REC market. These include California, a REC-importing state, New Mexico, a REC-exporting state, and Wyoming, which has no RPS obligation.

5.4 Transmission Investments

One might expect that increased trade of renewable certificates and power would imply a higher need for new transmission capacity, as discussed by Vajjhala et al. (2008); however, we find that this is not necessarily so. This is mainly explained because we are assuming that the RECs that are traded are unbundled, so they do not require physical delivery of out-of-state resources. We must remark that our conclusions about transmission investments do not directly apply for the case of considering bundled RECs, which require the physical delivery of those out-of-state resources, usually in the form of potentially inefficient dynamic transfers. In such a case, the transmission investment costs may significantly increase as the trade of those bundled RECs increases. On the contrary, our analysis considers tradable unbundled RECs, which may obviate the need for some large transmission infrastructure (since resources need simply to be delivered to the nearest load center, rather than across states).

Figure 5 shows aggregate transmission investment as a function of the percentage of unbundled REC trading allowed in the WECC. It reveals that optimal transmission investment for each scenario can either increase or decrease as flexibility is increased. The combination of two features can explain this behavior. First, transmission investments represent only a small fraction

Figure 5: Aggregate Transmission Investment Cost Versus the Percentage of Trading Allowed

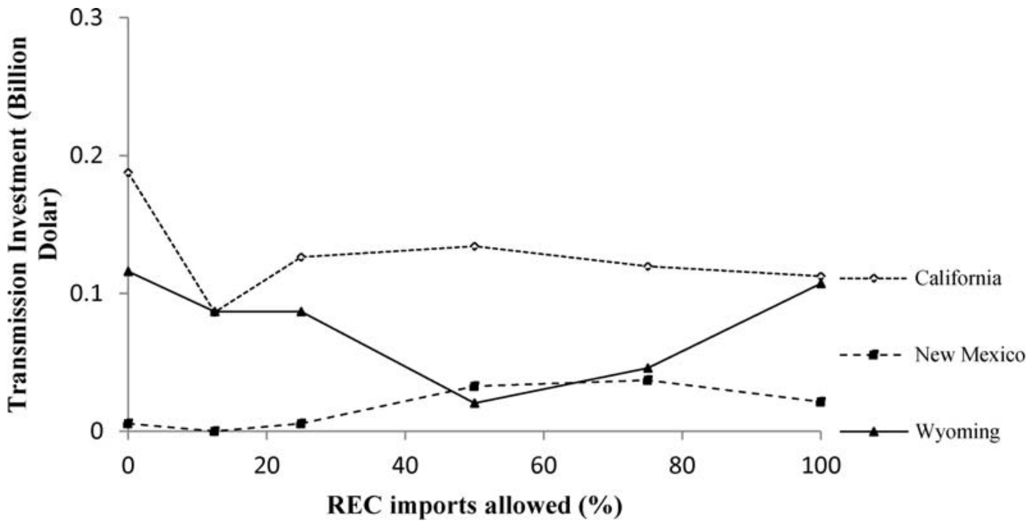


of the total costs (annualized transmission investment costs vary between \$0.4 billion and \$0.9 billion, while total annual system costs vary between \$27 billion and \$32 billion). Second, transmission investments are modeled as lumpy or "all-or-nothing" alternatives (i.e., transmission investment variables in the model are binary). As discussed in Munoz et al. (2013a), the indivisibility of transmission investments can result in extremely non-monotonic investment patterns as a function of the renewable targets. Although this prevents us from drawing general conclusions regarding correlations between gains from unbundled REC trading and transmission investment, these results highlight the importance of capturing the physical characteristics of transmission infrastructure. Indeed, in a sensitivity analysis, we removed the integrality constraints on transmission investment variables and assumed that transmission additions could be made in small increments, as in Vajjhala et al. (2008)—a common simplification of energy-economic models for policy analysis. We then found that the non-monotonicity observed in Figure 5 disappeared.

Figure 6 shows transmission investments in California, New Mexico, and Wyoming in the 1-Region scenario. For new transmission lines connecting two states, we assume, for simplicity reasons, that the states share transmission costs equally. As in the aggregate case (Figure 5), the lumpy characteristic of transmission investments leads to non-monotonic changes in investment as the flexibility of trading is increased. In California, for instance, transmission investment increases by 56% when we change allowed imports from 12.5% to 50%. This is consistent with the accompanying decreases in solar generation investment in California, which is replaced by imported wind generation. Counterintuitively, from 0% to 12.5% flexibility, transmission investment is reduced by 54%, which is explained by more intensive investments in conventional generation capacity within the state. In Wyoming, transmission investment increases substantially when increasing the allowed unbundled REC imports from 50% to 100%. The same situation occurs in New Mexico from 12.5% to 50% trading flexibility. This is mainly due to the REC exporting possibilities in those states.

Consistent with Munoz et al. (2013a), we also observe that the set of lines constructed under low levels of trading flexibility is not necessarily a subset of the lines that are selected under higher levels of trading flexibility. For instance, the transmission reinforcements selected for 25%

Figure 6: Transmission Investment Costs per State in the 1-Region Scenario



of unbundled REC trading flexibility in California are not all built in the 50% or 75% cases. This suggests that short-sighted planning with RPS designs that change year by year might lead to suboptimal transmission investments.

5.5 CO_2 Emissions

A voiced concern of states that do not allow LSEs to use out-of-state unbundled RECs is that some of the environmental benefits of renewables, such as air pollution reductions, would be shifted to other states with more efficient and inexpensive renewable resources.[10] Intuitively, a state that chooses to import unbundled RECs could make up for that power with local conventional generation. This could lead to an increase in local CO_2 and other emissions. However, this potential increment in emissions would be partially or completely offset by emissions reductions in states that export renewable certificates. Consequently, it is not intuitively obvious how increased unbundled REC trading impacts aggregate emissions.

Nonetheless, we must acknowledge that a REC importing region may end up with more emissions that may have nontrivial local impacts (e.g., NO_x or particulates). One possible solution to this issue might be coupling the REC trading regime with local pollution mitigation measures. However, such an analysis is beyond the scope of this paper and we leave it as a subject for future research.

Figure 7 shows the total amount of WECC CO_2 emissions as a function of the allowed percentage of unbundled REC imports. We find that the effect of different certificate trading schemes on aggregate CO_2 emissions is rather small, with a maximum absolute change of 3% with respect to the baseline scenario where no out-of-state RECs are allowed. Allowing for 100% of unbundled REC trading among states, in the 1-Region scenario, increases aggregate emissions levels by 1.6%

10. As discussed by Bushnell et al. (2008), these CO_2-emissions-reduction benefits are global and location independent. In spite of this, several states in the U.S. assign a higher value to local CO_2 emissions reductions than to potential abatements in neighboring regions due to the eventual co-benefits of mitigating actions over local pollutant emissions.

Figure 7: Aggregate WECC CO_2 Emissions as a Function of the REC Imports Allowed

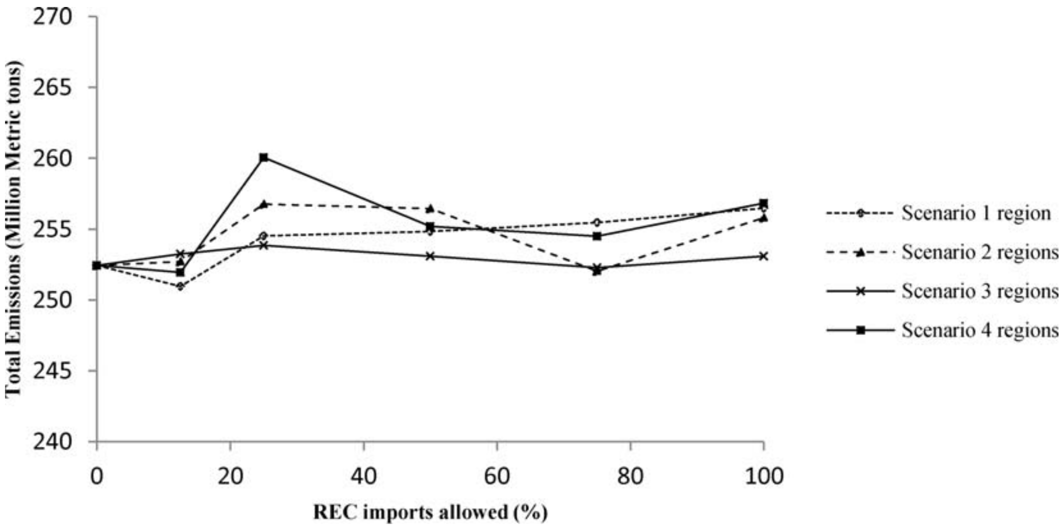
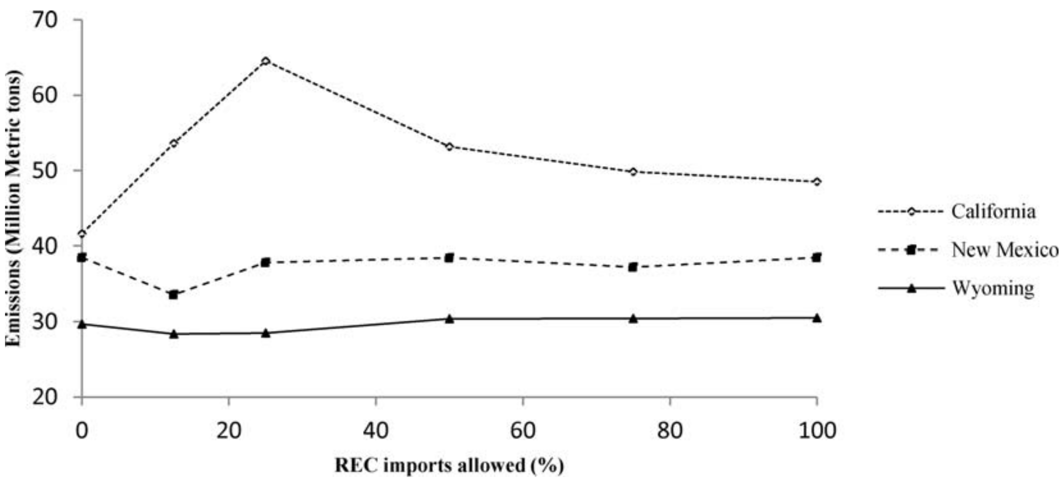


Figure 8: CO_2 Emissions per State in the 1-Region Scenario



with respect to the baseline scenario. Therefore, a more efficient allocation of generation investments in renewable energy technologies in the WECC does not necessarily yields lower levels of aggregate CO_2 emissions.[11]

Figure 8 shows the amount of CO_2 emissions in three states of the WECC as a function of the percentage of unbundled REC imports allowed. We find that the non-monotonic behavior of

11. There exist concerns that increasing penetrations of intermittent generation could increase emissions levels due to more frequent cycling, steeper ramps, and partially-loading of conventional generators. However, Lew et al. (2012) find that accounting for these features in production cost models increases CO_2 emissions by only 2% compared to our assumption of flat emissions curves.

transmission investments is somewhat mirrored in the annual CO_2 emissions levels per state as we increase trading flexibility. In California, for instance, CO_2 emissions decrease as the amount of unbundled REC imports allowed increases from 25% to 50% accompanied by an increase in transmission investment in the same range (Figure 6). This occurs because transmission capacity is not uniquely used to import power from renewables that are located outside of the state; it is also a partial substitute for conventional generation needed to meet in-state demand. Increasing unbundled REC trading flexibility from 25 to 50% displaces solar generation in California in favor of wind resources in neighboring states. This additional flexibility triggers investments in new "lumps" of transmission capacity to import power from the adjacent regions instead of new conventional generation within California. Therefore, increasing allowed REC imports from 25% to 50% yields CO_2 emissions reductions of 17.64% in the state (see Figure 8). In turn, the economic conditions that result from increasing REC trading flexibility further from 0% to 12.5% turn out to not justify the addition of more transmission in California. Indeed, transmission investment falls in that case. When unbundled REC imports are increased from 0% to 12.5%, transmission investment decreases and CO_2 emissions grow by 28.8% in the state due to increase in-state conventional generation. In summary, the effect of increased flexibility on unbundled REC trading leads to ambiguous changes in CO_2 emissions by state.[12]

In the case of New Mexico, wind and solar power generation increase when unbundled REC import limits are increased, making New Mexico a REC-exporting state. We find that CO_2 emissions in the state decrease by 12.8% when trading flexibility is increased from 0% to 12.5% in the 1-Region scenario. This is due to a reduction in the local use of coal and natural gas to generate power. In contrast, when we increase allowed REC imports further, from 12.5% to 25%, coal generation increases, which causes an increase in CO_2 emissions.

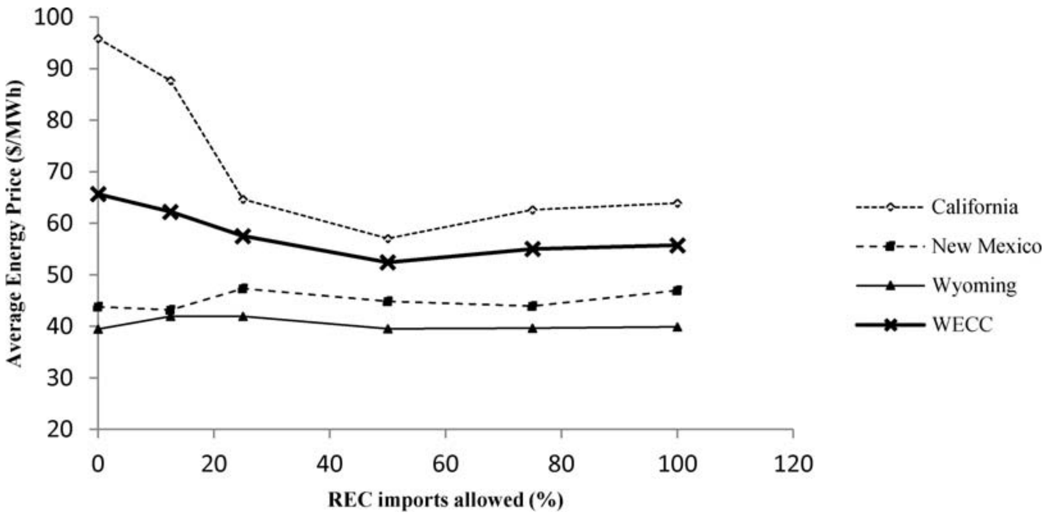
The state of Wyoming, on the other hand, does not have an RPS obligation, but when unbundled RECs are allowed, REC prices incent investment in solar and wind generation. Wyoming transmission investment increases as the amount of unbundled REC imports allowed by other states increases from 50% to 100% (Figure 6). And recall that in California, we observed that increased transmission investments led to both more energy imports and less in-state conventional energy production and, thereby, lower levels of CO_2 emissions in the state. However, in Wyoming, CO_2 emissions remain relatively constant over the same ranges of allowed unbundled REC imports (Figure 8), which highlights the unpredictability of the relationship between transmission investment and CO_2 emissions.

5.6 Energy Prices

Figure 9 shows the long-run average energy price in the WECC and in a sample of states as a function of the unbundled REC imports allowed for the 1-Region scenario. Results are similar for the other three geographic restriction scenarios. The average energy price in each state is computed by weighting nodal energy prices within a state by the demand at each of those nodes. Similarly, to compute the WECC system average price, we weight the average energy price in each state by the total demand of each state. Recall from Sections 3 and 4 that nodal energy prices correspond to the changes in the total system cost due to a 1-MWh variation in the load at that

12. For a more detailed account of the interaction between transmission indivisibilities and RPS designs, see Munoz et al. (2013a).

Figure 9: Average Energy Prices in the WECC and per State in the 1-Region Scenario



node, accounting for effects on energy balance constraints, reserve margin requirement constraints, and RPS constraints.

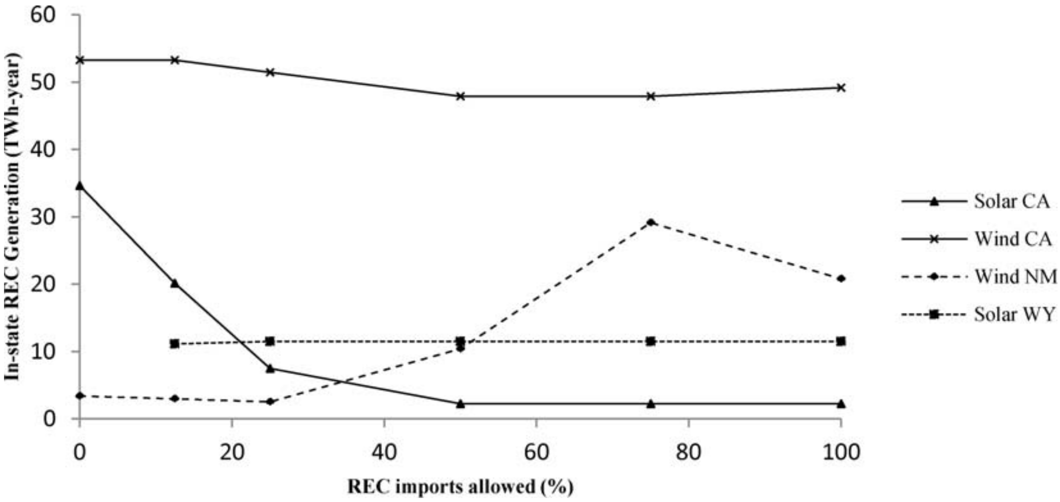
We find that increasing unbundled REC trading flexibility up to 100% reduces average energy prices in the WECC by 15.2% with respect to the case where no out-of-state RECs are allowed. This decrease is greater than the decrease in total cost (13.4%, Figure 2); they can differ because there is no necessary relationship between changes in marginal cost (the basis of nodal prices) and average cost. The change in energy prices, however, varies state by state. In California, for instance, the average energy price decreases by up to 33.3% as more unbundled REC trading is allowed. On the other hand, energy prices tend to increase slightly in the state of Wyoming. To help explain these differences, Figure 10 presents the in-state REC generation as a function of the unbundled REC trading allowed, in the 1-Region scenario.

As we see in Figure 10, the reduction of average energy prices in California is mostly a result of the displacement of high-cost in-state solar generation for RECs generated using cost-efficient wind from New Mexico. In contrast, the slight increase of average energy prices in Wyoming (a REC-exporting state) is a result of a modestly higher amount of solar generation and coal power plants generation as more trading is allowed. Meanwhile, in New Mexico, average energy prices tend to increase as the RPS policies become more flexible. This is because this REC-exporting state increases wind generation to supply renewable energy to the other states.

6. CONCLUSIONS AND POLICY IMPLICATIONS

Previous studies have called for reducing barriers to trade for renewable certificates in order to lower the cost of meeting renewable targets (Mozumder and Marathe, 2004; Berendt, 2006; Mack et al., 2011). Our study provides a careful quantification of those cost savings for the western US, in the case of considering unbundled RECs, along with impacts upon CO_2 emissions, transmission and generation construction, and energy prices. Our experiments apply a planning model that co-optimizes transmission and generation investments for the year 2022, using a 240-bus network representation of the WECC. The planning model incorporates realistic features that are often

Figure 10: In-state REC Generation by Technology and State, in the 1-Region Scenario



overlooked in high-level energy-economic models for policy analysis. These include parallel flow externalities (from Kirchhoff's laws), transmission investment indivisibilities, and the variability of renewable resources.

We find that the gains from trade that result when all states allow their load-serving entities to meet 100% of the renewable targets using out-of-state unbundled RECs are approximately $4.3 billion per year, compared to the situation in which no out-of-state RECs are allowed. These cost savings correspond to a 13.4% reduction in annualized cost of generation operations and new investment in generation and transmission. Remarkably, 90% of these economic gains can be captured by increasing the allowed unbundled REC imports from 0% to just 25%, assuming that trade is restricted to either 1 west-wide zone, or 2 or 3 subregions of WECC. Increasing trading flexibility beyond 25% yields additional, but much more modest, cost reductions. This trend is mirrored in the distribution of investment among different renewable energy technologies, which tends to stabilize together with total system cost once the in-state constraint is expanded beyond 25%.

However, much fewer of these benefits from importing unbundled RECs are achieved if myopically tight restrictions are placed on the geographic regions from which imports can come, similar to restrictions some states now have in place. When the west is divided into four regions, and unbundled REC imports are restricted to within each region, about $0.7 billion are lost (when considering the case of 100% unbundled REC trading flexibility). This is because, under a 4-Region scenario, the state of California would not be able to import RECs generated using relatively inexpensive renewable resources located in states like Utah and New Mexico. Thus restrictions on overall REC imports as well as the sources of those imports are both important.

We also find that increasing unbundled REC trading flexibility does not necessarily imply an increase in transmission investment cost, contrary what Vajjhala et al. (2008) suggest. Regarding this issue, it is important to remark that our analyses consider tradable unbundled RECs, which do not require physical delivery of out-of-state renewable resources and, thus, may obviate the need for some large transmission infrastructure. In our analysis, transmission investments in some policy scenarios are double those in others, but the scenarios with the most unbundled REC trading flexibility do not have the most investment. This occurs because (a) transmission investment costs represent a small fraction of the total system cost and (b) transmission infrastructure has a lumpy nature. Our results highlight the importance of jointly studying renewable energy integration and transmission planning, since investment in renewables affects the desirability of investment in transmission, and vice versa, in contrast to analyzing each of them in isolation (Liu et al., 2013).

Similarly, we find that increased unbundled REC trading flexibility neither decreases nor increases CO_2 emissions significantly—so trading's major benefit is cost savings rather than emissions reductions. Aggregate levels remain roughly constant as we change the RPS designs. Contrary to what some regulators fear, the redistribution of CO_2 emissions per state with increased levels of unbundled certificate trading flexibility is usually minimal, although California emissions are significantly smaller under some specific levels of allowed unbundled REC imports. However, we note that there could be longer term emission benefits of trading: if efficient unbundled REC trading lowers the cost of RPS compliance, this could encourage states to adopt more ambitious renewable targets, which could then yield additional CO_2 reductions.

We find that average energy prices are more sensitive than CO_2 emissions to the design of RPS policies. Although the WECC-wide average energy price would decrease modestly as RPS policies become more flexible, average energy prices in some states may change significantly. In California, for instance, displacing costly in-state solar generation with cheaper out-of-state wind could yield average energy price reductions of up to 33.3% as trading flexibility is increased. In contrast, energy prices in Wyoming tend to slightly increase as the RPS policies become more flexible. This is mainly due to an small increase in demand for that state's solar and coal generation as more unbundled REC trading is allowed; demand for both types of generation from Wyoming increases as a byproduct of building more transmission.

There are several potential directions for future work on the interaction of REC trading policies and power markets. A direct extension of our research would be to consider all the states of the U.S. with heterogeneous certificate trading schemes. Such implementation would better represent each state's renewable incentives and trading restrictions, such as inconsistent definitions of qualifying renewable resources and carve-outs for particular renewable types. The same framework could also be applied directly to the European Union, where countries have enacted independent RPS goals and emissions targets. Second, our approach could also be extended to consider clean energy standards or carbon policies (such as USEPA's recently announced Section 111(d) initiative), which do not just promote generation from renewables, but also technologies such as natural gas, nuclear power, and energy efficiency measures.

ACKNOWLEDGMENTS

We thank S. Kasina and J. Ho of JHU for their help with the dataset for this model. This research was partially supported by the CONICYT, FONDECYT/Regular 1130781 grant, the CONICYT, FONDAP 15110019 grant, the Consortium for Electric Reliability Technology Solutions (CERTS) funded by the USDOE, NSF grants IIA 1243482 and ECCS 1230788, and the Department of Energy's Office of Advanced Scientific Computing Research (ASCR). Sandia National Laboratories is a multi-program laboratory managed and operated by Sandia Corporation, a wholly owned subsidiary of Lockheed Martin Corporation, for USDOE's National Nuclear Security Administration under Contract DE-AC04-94-AL85000.

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APPENDIX A: NOMENCLATURE

Sets and Indexes

B	Set of buses, indexed by b or p.
B_i	Set of buses at state i.
FG	Set of flowgates, indexed by a.
G	Set of generators, indexed by k.
G_b	Set of generators at bus b.
G_i	Set of generators at state i.
G_R	Set of renewable generators.
G_C	Set of candidates generators.
G_I	Set of intermittent generators.
G_{NI}	Set of non-intermittent generators.
H	Set of hours, indexed by h.
J	Set of reliability regions, indexed by j.
L	Set of transmission lines, indexed by l.
L_E	Set of existing transmission lines.
L_C	Set of candidate lines for investment.
R	Set of states with renewable obligations, indexed by i.
R_m	Subsets of states with renewable obligations (geographical constraints).
Ω_l	Set of pairs of nodes connected to line l.

Parameters

CX_l	Capital cost of line l [\$].
CY_k	Capital cost of generator k [\$/MW].

$D_{b,h}$	Forecast demand at bus b and hour h [MW].
$ELCC_k$	Effective Load Carrying Capability Factor at generator k.
$\overline{F_l}$	Capacity of transmission line l [MW].
$\overline{FG_a}$	Limit at flowgate a (fraction of the line capacity that is allowed to be used in flowgate a).
h^*	Peak demand hour.
M_l	Large positive number depending of line l.
MC_k	Marginal cost of generator k [$/MWh].
NC	Noncompliance penalty [$/MWh].
RM_j	Reserve margin requirement at reliability region j.
RPS_i	Renewable obligation at state i.
S_l	Line susceptance of line l [p.u.].
$VOLL$	Value of lost load [$/MWh].
$W_{k,h}$	Hourly capacity factors for wind and solar at generator k and hour h.
$\overline{Y_k}$	Maximum resource potential at generator k [MW].
$Y^0{}_k$	Initial installed generation capacity at generator k minus retirements [MW].
α	Fraction of RPS that must be generated from each state.
δ	Discount rate.
$\phi_{b,l}$	Element of node-line incidence matrix.
$\Psi_{a,l}$	Element of flowgate-line incidence matrix.
T_l	Lifetime of transmissions investments in line l [years].
T_k	Lifetime of generation investments in generator k [years].

Variables

$f_{l,h}$	Power flow at line l and hour h [MW].
$g_{k,h}$	Power generation at generator k and hour h [MW].
n_i	Noncompliance of renewable target at state i [MWh].
$r_{b,h}$	Load curtailment at bus b and hour h [MW].
$\theta_{b,h}$	Phase angle at bus b and hour h [Radians].
y_k	Power generation capacity of new generator k [MW].
x_l	Transmission investment decision of line l.

APPENDIX B: DESCRIPTION OF THE CANDIDATE RENEWABLE RESOURCES IN THE WECC

Table 3: Installed Capacity by Technology for each State (MW).

State / Technology	AZ	CA	CO	MT	NM	NV	OR	WA	UT	ID	WY
Biomass	0	558	0	0	0	0	0	0	0	0	0
Gas	10,950	21,196	5,047	267	2,549	7,907	1,820	5,446	1,760	293	659
Geothermal	0	1,700	0	0	0	118	0	0	37	0	0
Nuclear	4,113	4,499	0	0	0	0	0	1,160	0	0	0
Renewable	30	1,001	0	0	0	98	75	508	61	35	0
Solar	0	571	0	0	0	0	0	0	0	0	0
Wind	240	2,256	597	190	0	50	1,591	630	0	236	248
Coal	2,685	0	3,752	2,225	5,889	707	452	1,290	5,091	13	4,675

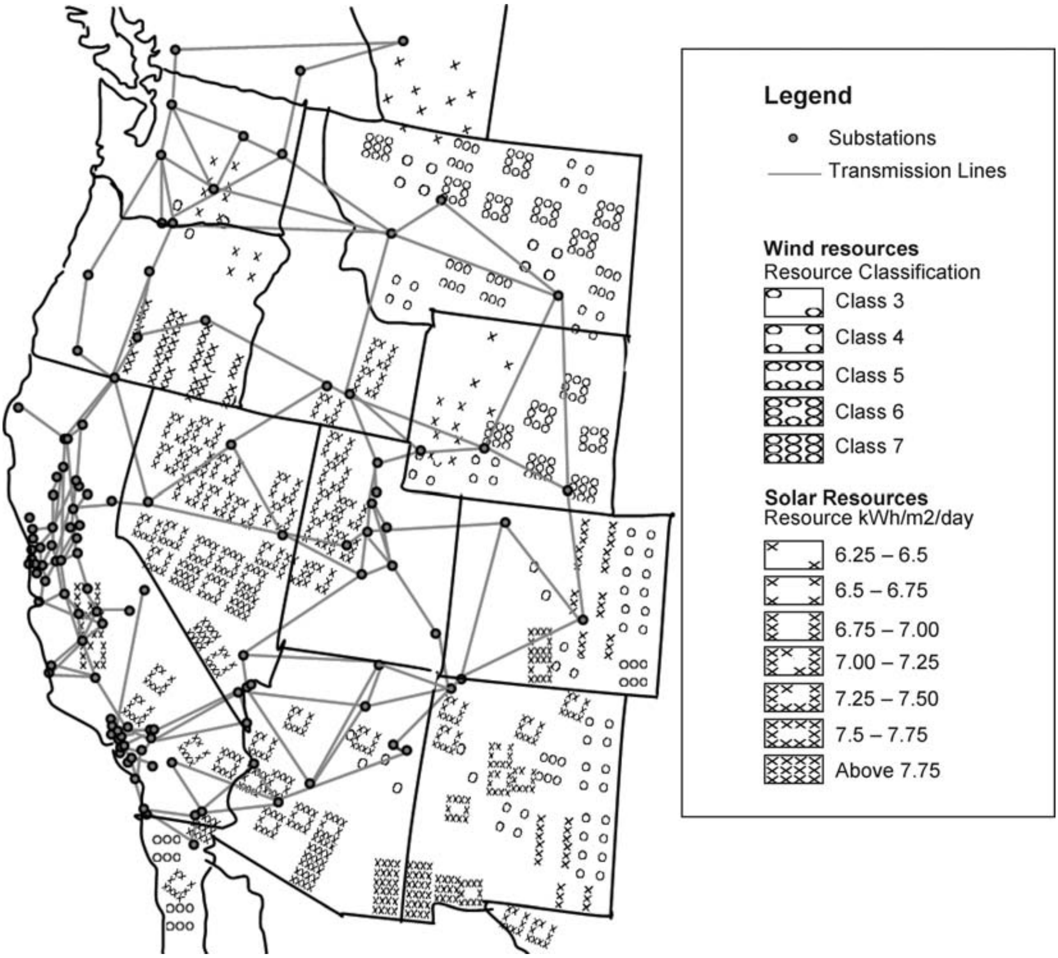
Table 4: Available Installed Capacity for New Investments, by Technology by State (MW)

State / Technology	AZ	CA	CO	MT	NM	NV	OR	WA	UT	ID	WY
Biomass	489	0	141	147	44	318	349	448	3	358	29
Gas	120,000	1,020,000	120,000	120,000	120,000	180,000	180,000	180,000	60,000	60,000	60,000
Geothermal	0	0	0	0	0	1,368	832	32	225	279	0
Solar	74,361	62,569	4,943	0	183	56,303	0	0	15,868	0	3,022
Wind	8,363	14,093	12,394	11,458	11,290	1,406	4,949	5,463	1,678	1,603	19,071
Coal	2,685	0	3,978	2,225	5,889	1,037	452	1,290	5,091	13	4,675
Hydro	0	0	0	0	0	2	557	165	0	8	0

Table 5: Correlations for a Sample of Load, Wind, and Solar Profiles.

		Demand profiles per region					Wind profiles per state							Solar profiles per state			
		SOUTHWST	BAYAREA	NORTHWST	CANADA	ROCKYMT	CA	AZ	NM	CO	NV	AZ	WA	CA	AZ	NM	CO
Demand	SOUTHWST	1.00															
	BAYAREA	0.71	1.00														
	NORTHWST	0.42	0.70	1.00													
	CANADA	0.25	0.68	0.91	1.00												
	ROCKYMT	0.67	0.82	0.86	0.79	1.00											
Wind	CA	-0.27	-0.28	-0.21	-0.21	-0.26	1.00										
	AZ	-0.21	-0.18	-0.15	-0.13	-0.18	0.49	1.00									
	NM	-0.27	-0.15	-0.01	0.06	-0.09	0.20	0.38	1.00								
	CO	-0.31	-0.19	-0.03	0.04	-0.14	0.23	0.41	0.77	1.00							
	NV	-0.30	-0.12	0.04	0.08	-0.04	0.46	0.37	0.20	0.20	1.00						
	AZ	-0.33	-0.16	-0.02	0.03	-0.11	0.48	0.55	0.22	0.26	0.83	1.00					
	WA	-0.16	-0.11	-0.03	0.06	-0.06	0.09	0.08	0.18	0.27	-0.03	0.03	1.00				
Solar	CA	0.23	0.40	0.32	0.32	0.36	-0.07	-0.10	0.02	-0.01	-0.01	-0.07	0.05	1.00			
	AZ	0.25	0.43	0.32	0.34	0.37	-0.08	-0.10	0.01	-0.02	-0.01	-0.07	0.03	0.96	1.00		
	NM	0.24	0.42	0.33	0.34	0.37	-0.07	-0.10	0.02	-0.01	-0.01	-0.07	0.04	0.96	0.98	1.00	
	CO	0.23	0.41	0.33	0.34	0.37	-0.06	-0.09	0.02	0.00	-0.01	-0.06	0.04	0.96	0.97	0.98	1.00
Mean		15,077	4,246	21,299	14,160	9,593	0.37	0.26	0.31	0.34	0.27	0.26	0.23	0.24	0.22	0.23	0.22
Std. Dev.		3,328	741	3,289	1,571	1,348	0.29	0.25	0.26	0.27	0.25	0.21	0.21	0.32	0.30	0.30	0.29

Figure 11: Location of Solar and Wind Resources in the WECC



Source: NREL (2012a; 2012b)