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# Gains From Trade Versus the Cost of Transmission: The Economic Effects of Interregional Trading of Renewable Energy Certificates in the WECC

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**Gains from Trade versus the Cost of Transmission:**

**The Economic Effects of Interregional Trading of Renewable Energy Certificates in the WECC**

A. P. Perez[1], E. E. Sauma[1,]*, F. D. Munoz[2], and B. F. Hobbs[3]

**Abstract**

In the United States, 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 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. The flexibility was analyzed in terms of the amount and geographic eligibility of out-of-state RECs that can be used in meeting state RPSs' goals. Although more trade would be expected to have economic benefits, the magnitude of these benefits relative to the cost of additional transmission infrastructure is less certain. It is also unclear the effects of such trading on $CO_2$ emissions and energy prices. We find that most of the economic benefits are captured with approximately 25% of interstate exchange of RECs. 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 in others, while WECC-wide average energy price slightly decreases.

**Keywords:** Renewable Portfolio Standards, Renewable Energy Credits, transmission planning, Western Electricity Coordinating Council, electricity markets.

## 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). Poli-

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cies that explicitly promote generation from renewable generation technologies include Renewable Portfolio Standards (RPS), Feed-in Tariffs (FITs), and Renewable Auction Mechanisms (RAMs) (Sauma, 2012a). Other environmental policies, such as carbon taxes or cap-and-trade programs, aim at reducing greenhouse gas emissions and do not specify renewable 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 unit 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, load-serving entities that fall short of the minimum number of RECs required by the RPS can still meet the mandate by purchasing certificates from LSEs that hold RECs in excess of their target (Elder, 2007; Cory and Swezey, 2007). To further reduce the expense of meeting the regulation, some RPS implementations allow utilities to meet a fraction of the renewable goal with RECs from resources that lie outside of the mandate's jurisdiction. This allows LSEs to take advantage of the most cost-efficient renewable resources available for deployment, independent of location. The European Union is currently studying the replacement of national renewable targets with an overall European goal after 2020 (Castle, 2014).

Empirical and theoretical studies have found that these and other sources of flexibility of emissions policies may have unintended consequences on the 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, 2012b). 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 requirements that some states impose on LSEs regarding RECs obtained from in-state sources. They conclude that limiting the geographical eligibility of RECs leads to both more volatile and less liquid markets for RECs. Berendt (2006) reaches a similar conclusion and proposes 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 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, finding that ignoring Kirchhoff's Voltage Laws (KVLs) or transmission investment indivisibilities can significantly bias investment portfolios. Munoz et al. (2013b) propose a stochastic investment-planning model that co-optimizes the transmission and generation infrastructure. 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 different 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 REC trading schemes.

As mentioned earlier, trading of RECs among regions to meet RPS targets should have a positive aggregate impact, but there is less certainty about the magnitude of the benefits relative to the costs of additional transmission infrastructure that might be needed under the changed pattern of renewable investment. It is also unclear whether such trading would further support environmental objectives, namely greenhouse gas emissions reductions. In this article we quantify the economic benefits of allowing increased trade of RECs among states in the Western Electricity Coordinating Council (WECC) in order to meet their renewable targets. 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 loop-flow effects due to Kirchhoff's Laws. Assuming projected state renewable targets, we study the impact of different degrees of REC trading flexibility upon the total system cost and transmission 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 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. 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%. Further, we find that transmission investments can either increase or decrease as more trading is allowed.

The rest of the article is organized as follows. Section 2 presents a simplified two-region example that we use to illustrate 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 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. The Economics of REC Trading in a Two-Region Example

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

Now imagine that the two regions are considering the possibility of creating an integrated market for renewable energy certificates to provide LSEs more flexibility to meet each region's RPS. They are certain that inter-regional 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 regions so that there is no congestion that limits energy trade between them. If regions 1 and 2 do not allow LSEs to exchange RECs to meet the local renewable targets, the least-cost solution for renewable generation is $r_1 = 90$ and $r_2 = 40$ TWh (see scenario a.1 in Table 1). 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. 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., $REC_1 = LC_1(90) - C(185) = 120.5$). In this scenario, the price differential of RECs is solely a result of distinct renewable resource qualities, since both LSEs select the same conventional generation levels.

On the other hand, if LSEs are allowed to trade certificates (see scenario a.2 in Table 1), the most economical levels of conventional and renewable generation are such that all the incentives for arbitrage of renewable certificates between regions are eliminated (i.e., $LC_1(r_1) - C(c_1) = LC_1(r_2) - C(c_2)$). 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, the interregional trading of RECs reduces cost by 6.2% compared to the scenario that prohibits RPS compliance using out-of-region resources; these savings stem from more efficient use of the available renewable resources in both regions. The displacement of renewable generation from region 1 to region 2 also affects regional energy prices. In this case, free trade in renewable certificates causes the electricity price to fall by 18.9% (84.6 to 68.6 \$/MWh) in region 1, but to increase by 6.7% in region 2 (58.0 to 61.9 \$/MWh). As the location and amounts of conventional generation are unaffected by the REC trading scheme, greenhouse gas emissions per region remain unchanged.

**Table 1:** Results for different trading schemes and transmission costs in the two-region 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 REC trading | 0 | 185.0 | 185.0 | 90.0 | 40.0 | 30.0% | 20.0% | 25 | 84.6 | 58.0 | 120.5 | 47.5 | 28,797.5 |
| **a.2** 100% of trading 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 REC trading | 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** 100% of trading 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 REC trading | 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** 100% of trading allowed | Infinite | 250.0 | 120.0 | 50.0 | 60.0 | 16.7% | 30.0% | 0 | 76.0 | 56.0 | ---70.0--- | | 27,500.0 |

Now let's assume that the existing transmission infrastructure linking regions 1 and 2 is fully congested and that any exchange of power between regions costs 3.13 \$M/TWh.[4] As shown in Table 1, this transmission cost reduces exports from region 2 to region 1 by 62.4% if no trading of RECs is allowed

[4] 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.

(scenarios a.1 vs. b.1) and by 24% if the LSEs are allowed to exchange certificates (scenarios a.2 vs. b.2). This also leads to shrinkage of the economic savings from REC trading from 6.2% ($1,776M from scenario a.1 to a.2) to 5.6% ($1,627 from scenarios b.1 to b.2). Notice that the 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.

Table 1 also summarizes the results for the case where exchange of power between the regions 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. 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 trading is allowed (scenarios a.2 and b.2), in scenario c.2, region 1 imports RECs from region 2 to meet the local RPS. However, in this case, region 1 cannot take advantage of cheaper (on the margin) conventional generation in region 2, which results from region 2's comparatively lower demand level. Assuming that conventional generation has a constant $CO_2$ emissions rate per MWh, the free trading of RECs in scenario c.2 increases region 1's emissions by 19% with respect to scenario c.1, even though the total emissions across the two regions is unchanged. Consequently, under this scenario of constraints, region 1 might not support an interregional market of 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 regions is unchanged (40 TWh of conventional generation are displaced from region 2 to region 1). On the other hand, if the two regions had different emissions rates for conventional generation, free trade in RECs could either increase or decrease total emissions, depending on which region has the more polluting technology.

This simple example illustrates how transmission constraints/costs and the economic and environmental effects of the interregional exchange of RECs interact. However, estimating the effects of 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. 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.[5] 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 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 the Appendix. Generators can be dispatched at level $g_{k,h}$ MW with marginal cost $MC_k$ \$/MWh. We denote transmission and generation investment variables as $x_l$ (bina-

[5] We use the year 2022 to ensure a long-term stabilization of current investments. 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.

ry) and $y_k$ MW, with annualized capital costs $CX_l$ \$/yr and $CY_k$ \$/MW/yr, respectively.[6] 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, $\mathrm{RPS_i}$ (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:

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

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

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

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

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

$$\big|f_{l,h}\big| \;\le\; \overline{F_l} \qquad \forall\, l \in L_E, h \tag{7}$$

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

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

$$y_k \le \overline{Y}_k \qquad \forall\, k \tag{10}$$

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

$$\sum_{l \epsilon L} \Psi_{a,l} \, f_{l,h} \le \overline{FG_a} \left[ \sum_{l \in L_E} \big|\Psi_{a,l}\big| \overline{F_l} + \sum_{l \in L_C} \big|\Psi_{a,l}\big| \overline{F}_l x_l \right] \qquad \forall\, a, h \tag{12}$$

---

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

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

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

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

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

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 region, 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 $\alpha$ 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). The system is composed of 240 buses, 140 generators (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 (NREL, 2012b). 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*.

**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 (GWh/year) | 111.1 | 350.9 | 61.8 | 22.8 | 19.0 | 21.7 | 69.3 | 108.8 | 38.9 | 130.4 | 11.8 |
| RPS target (%) | 15 | 33 | 30 | - | 15 | 20 | 25 | 13 | 20 | 12 | - |
| RPS Demand (GWh/year) | 16.7 | 115.8 | 18.5 | - | 2.9 | 4.3 | 17.3 | 14.1 | 7.8 | 15.6 | - |

*Our model also considers demand in Mexico and Canada (Baja California: 21.5 GWh/yr, Alberta: 83.5 GWh/yr and British Columbia: 76 MWh/yr).

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.

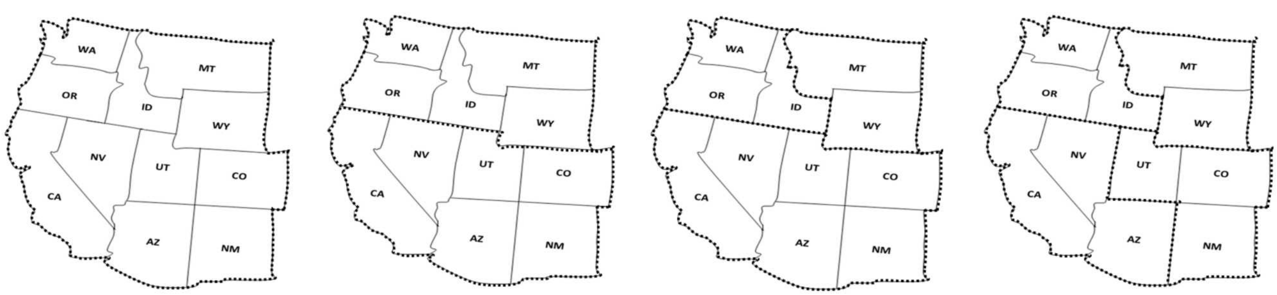
### 4.2. Methodology and Experiments

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 trading schemes:

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 RECs imported 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 $\alpha$ in constraint (13). We simulate the second aspect of trading flexibility —the geographic eligibility of RECs from out-of-state resources— by defining four distinct hypothetical configurations of trading 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.

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




(a) (b) (c) (d)

Some examples of these restrictions are the following. Colorado's RPS, for instance, does not require in-state deliverability of renewable generation. LSEs in the state are allowed to fulfill 100% of their renewable requirements by purchasing RECs from renewable generators located in any other state of the country. This is partially emulated in the 1-Region scenario (Figure 1a). The state of Washington also allows LSEs to import renewable certificates from out-of-state renewable resources, but only from generators located in the Pacific Northwest (captured by the 3- or 4-Region scenarios in Figures 1c and 1d, respectively). Other states, including California, require a minimum percentage of the mandate to be met using in-state renewable resources. Arizona, 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 renewable-target noncompliance. Although our penalty of 500 \$/MWh exceeds the noncompliance fines of most renewable mandates, it is based on observed Solar REC (SREC) prices in the U.S. and represents an upper bound on the marginal cost of supplying renewable power.

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.[7] 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

[7] Nodal energy prices are computed as: $\frac{\partial(O.F.)}{\partial D_{b,h}} = \sum_C \frac{\partial\left(RHS(C)\right)}{\partial D_{b,h}} * D_{b,h}$ . 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 demand. To facilitate computation of a dual price that captures the effect of demand changes upon all of these constraints, we 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 are then given by the dual variable associated with the auxiliary constraint $d_{b,h} = D_{b,h}$.

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.

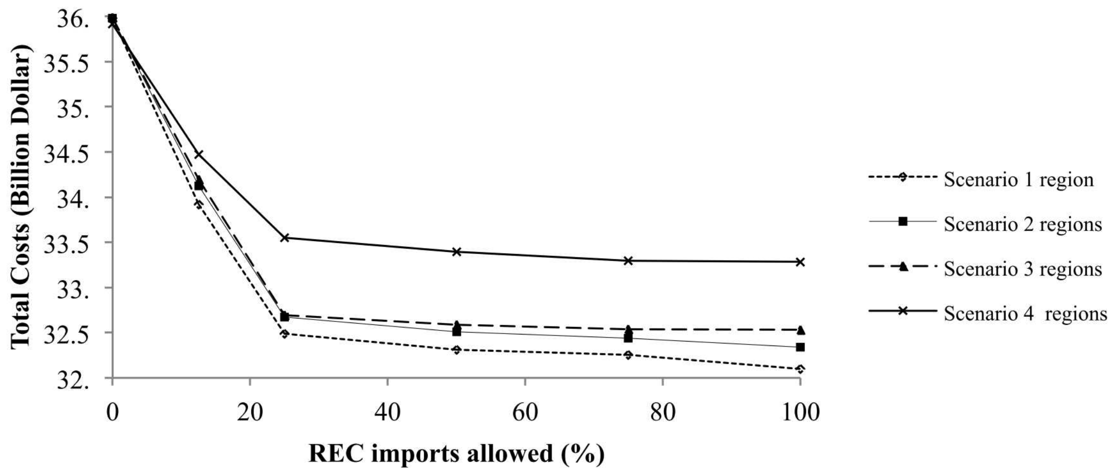
## 5. Results and Discussion

The following subsections summarize the results from our numerical experiments. We study how REC trading affects total system cost, exports and imports of RECs by state, generation capacity investments, transmission investments, $CO_2$ emissions, and energy prices. 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 for the four geographically-constrained scenarios and for different degrees of REC trading flexibility, ranging from 0% to 100%. The 1-Region scenario with no restrictions on the amount of certificates traded (i.e., 100% 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 (\$32.1 billion/yr, the point in the bottom right of Figure 2) and it is 10.8% cheaper than the reference case, in which trading of renewable certificates is not allowed (\$36.0 billion/yr, the point in the top left of Figure 2). These cost savings of \$3.89 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). States can, therefore, reduce the costs of meeting their RPS targets by expanding their definition of eligible renewable resources. Interestingly, most of the cost savings can be captured by allowing a relatively modest level of REC trading flexibility.

**Figure 2:** Total Cost as a Function of Trading Flexibility.




As shown in Figure 2, the first 25% of flexibility yields a cost reduction of approximately \$3.5 billion/yr with respect to the reference case where no trading is allowed, as long as there are three or fewer regions. This is 90% of the cost savings that could be attained if states were allowed to use an unlimited amount of out-of-state resources to meet their local targets (100% trading allowed). Increasing the 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 \$32.5 billion to \$32.3 billion (under the 1-Region scenario).

There are two potential causes for this "knee" on the total system cost curve at 25% of flexibility. First, the knee could reflect the depletion of high quality or cost-efficient renewable resources within WECC. Allowing further trading of 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 REC trading flexibility, the system requires more transmission capacity 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 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.[8] We will analyze both generation and transmission investments in detail in the following sections.

Figure 2 also illustrates the effect of restricting the geographical eligibility of renewable certificates 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 certificates (scenario 1). We find that the 2- and 3-Region configurations increase compliance cost by only 0.7% and 1.4% with respect to the most flexible policy design (scenario 1, 100% of trading allowed). However, the 4-Region configuration increases cost by 3.7%. 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 high quality renewable resources from Utah, Colorado, and New Mexico. In contrast, in the 4-Region scenario, California imports RECs from the states of Nevada and Arizona, which are not net REC exporters under the other three scenarios because of the relatively low quality of their wind and solar resources.

In summary, trading 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 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.

### 5.2. Geographical Allocation of RECs

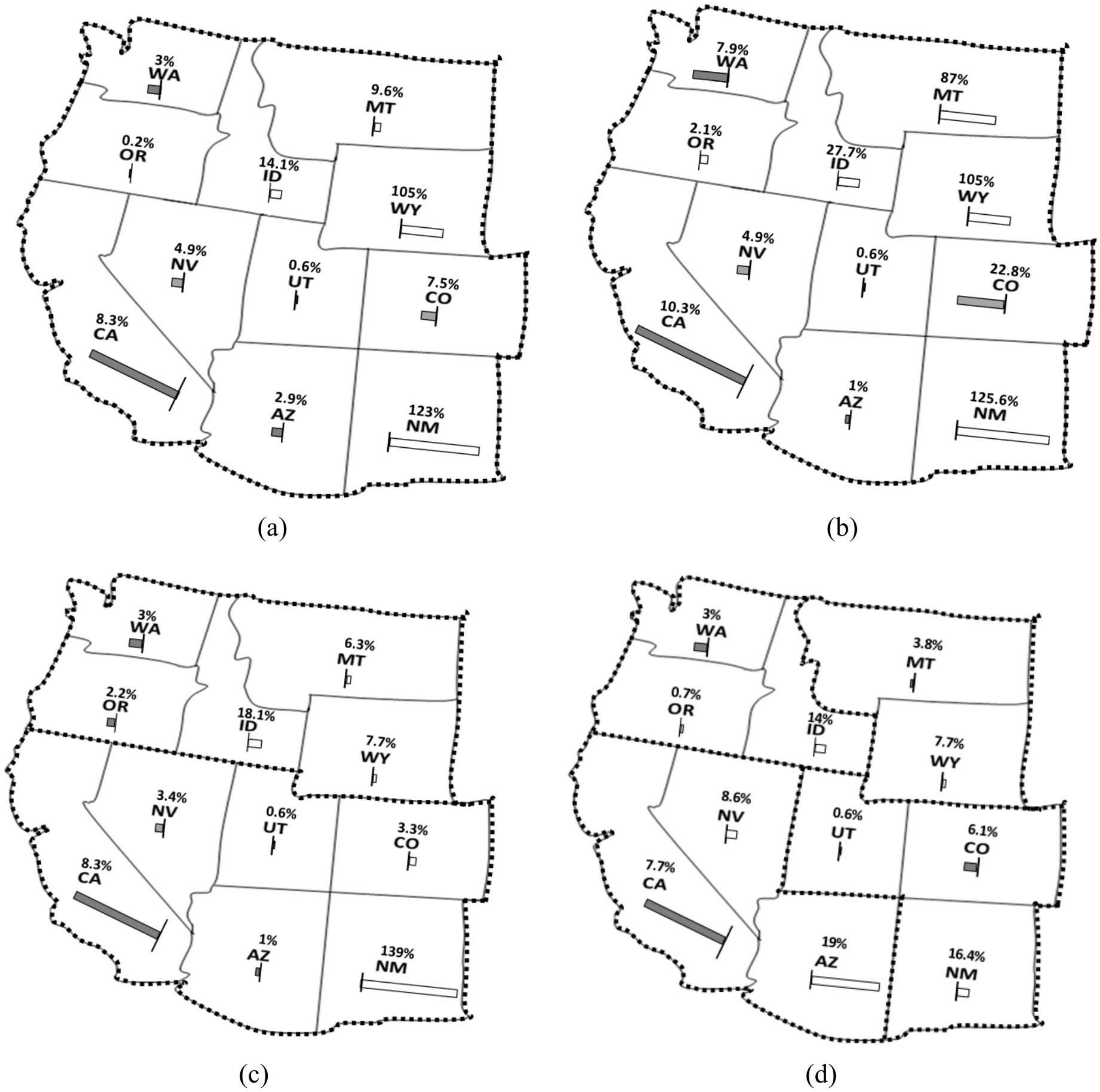
When REC trading is allowed, states that generate more renewable energy than the local RPS target are able to sell RECs to states that fall short of their targets. In contrast, when REC trading is not allowed, all states meet their RPS targets with in-state renewable generation. Figure 3 shows REC transactions for four different REC trading schemes. The sizes of the bars represent the magnitudes of the exports (white bars) or imports (dark bars) of RECs. The fraction of a state's demand that is exported or imported by the

[8] 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.

state is shown in Figure 3 as a percentage. For instance, in Figure 3a, the size of California's bar corresponds to 29 GWh per year of renewable energy imported, representing 8.3% of the state's demand.

We find that, in the 1-Region scenario (WECC-wide market of certificates), increasing the allowance of 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 Idaho, New Mexico, Montana, Utah, and Wyoming export RECs to Arizona, California, Colorado, Nevada, and Washington. The exception is the state of Oregon, which becomes an exporter of certificates when the percentage of trading flexibility is increased from 25% to 100%. Note that neither Idaho nor Wyoming have enacted RPS targets (see Table 2), yet, they become exporters of RECs when their certificates are eligible to meet other state's renewable targets. In the case of Wyoming, the equivalent of more than 100% of the state's demand is exported in the form of RECs. Renewable resources are developed in these states as a consequence of the additional revenues generated from the exchange of certificates; they make some of the high quality renewable resources in Idaho and Wyoming economically viable without the need for local regulatory incentives.

**Figure 3:** REC exports (white bars) and imports (dark bars) in the following cases: (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.



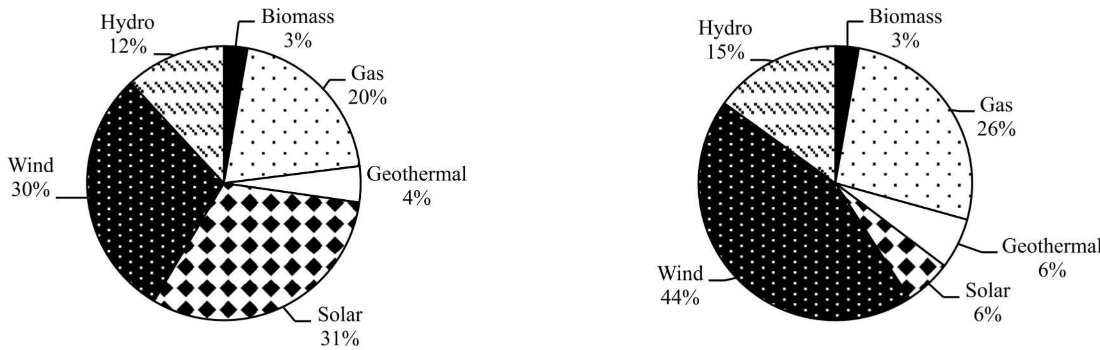

However, the number of exporting states does significantly depend on the geographic trading configurations. For instance, looking at the states selling RECs when 25% of REC flexibility is allowed, 5 states export RECs in the 1-Region scenario, 6 states export RECs in the 2-Region scenario, 5 states export RECs in the 3-Region scenario, and 7 states export RECs in the 4-Region scenario. Moreover, which states export RECs also varies. For example, comparing the results when 25% of REC trading is allowed in the 2-Region scenario (Figure 3c) and in the 4-Region scenario (Figure 3d), five states (Montana, Oregon, Nevada, Colorado, and Arizona) switch from net importers to net exporters or vice versa. Consequently, the way geographical restrictions of REC trading are defined has important effects on REC trading. For other levels of REC flexibility, we observe similar changes in the patterns of REC trading.

### 5.3. Investments in Generation Capacity

Here we study the changes in the generation investments by technology as 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 REC trading is allowed (reference case, Figure 4a) and when 100% REC trading is allowed (Figure 4b). When full flexibility is allowed generation investment costs decrease by 21% with respect to the case without REC trading. 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 trading. This is a result of the flexibility imparted by RPS policies that permit 100% imports of RECs, which allows states to take advantage of the most cost effective renewable resources anywhere in the WECC, including states such as Wyoming and Idaho that do not have RPS obligations.

**Figure 4:** Generation investment expenditures by technology in the 1-Region scenario, when (a) no REC trading is allowed, and when (b) 100% of REC trading flexibility is allowed.




Total generation investment costs: \$18.5 billion

(a)

Total generation investment costs: \$14.6 billion

(b)

Our numerical simulations suggest that inflexible state RPS policies (Figure 4a) require significant investment in solar generation, particularly in California. As shown in Figure 4a, solar represents 31% of the cost of generation capacity investments needed to meet state RPS policies, as opposed to 6% in the scenario of flexible RPS policies (Figure 4b). In the latter, solar generation is replaced with cost-effective wind resources from Wyoming, New Mexico, and Montana. Wind in these states is highly correlated with load and cheaper than solar on a per-MW basis. We also note that, although investments in natural gas powered generation as a fraction of total investment costs increase from 20% to 26%, the variation in the generation investment costs implies that the exact cost increment with respect to the case of inflexible RPS policies is only 3.7%.

In the following subsections we analyze how 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. Figure 5 shows aggregate transmission investment as a function of the percentage of 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 of the total costs (annualized transmission investment costs vary between \$0.4 billion and \$0.9 billion, while total system costs vary between \$32 billion and \$36 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 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 5:** Aggregate transmission investment cost versus the percentage of trading allowed.

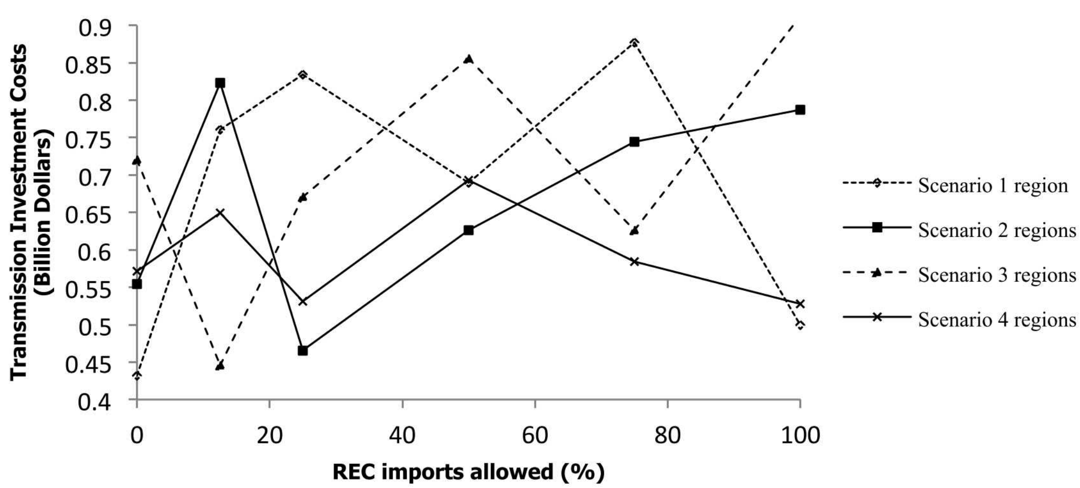
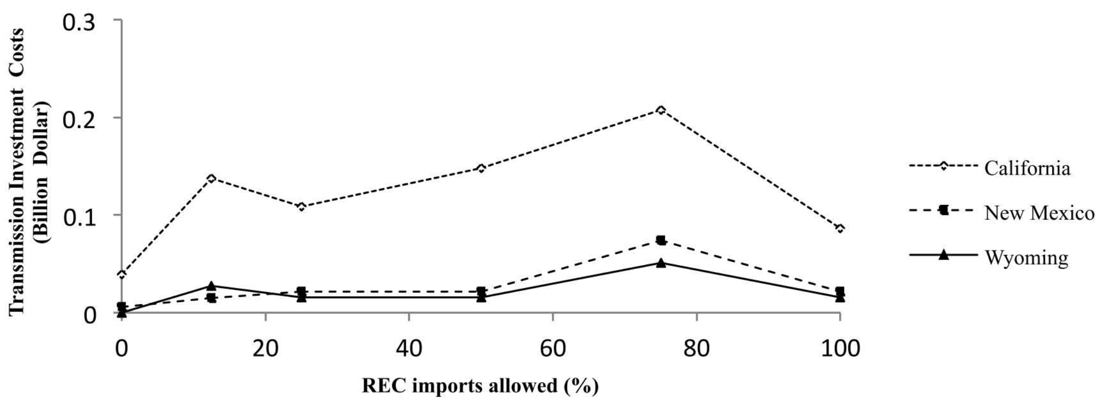



Figure 6 shows transmission investments in California, New Mexico, and Wyoming in the 1-Region scenario. For new transmission lines connecting two states, we assume that the states share transmission costs equally. As in the aggregate case (Figure 5), the lumpy characteristic of transmission investments leads to non-monotonic changes in investment as the flexibility of trading is increased. In California, for instance, transmission investment increases by 249% when we change allowed imports from 0 to12.5%. Except for the interval between 12.5% and 25% of allowed imports, transmission cost continues increasing up to 75%. This is consistent with a lower level of solar generation investments in California, in these ranges of allowed imports, which is replaced by imported renewable generation. Counterintuitively, adding an extra 25% of trading flexibility (from 75% to 100%) reduces transmission cost by 58%, which is explained by more intensive investments in conventional generation capacity within the state. In Wyoming and New Mexico, transmission investment increases substantially only when increasing the allowed REC imports from 50% to 75%. This is mainly due to the REC exporting possibilities in those states.

**Figure 6:** Transmission investment costs per state in the 1-Region scenario.



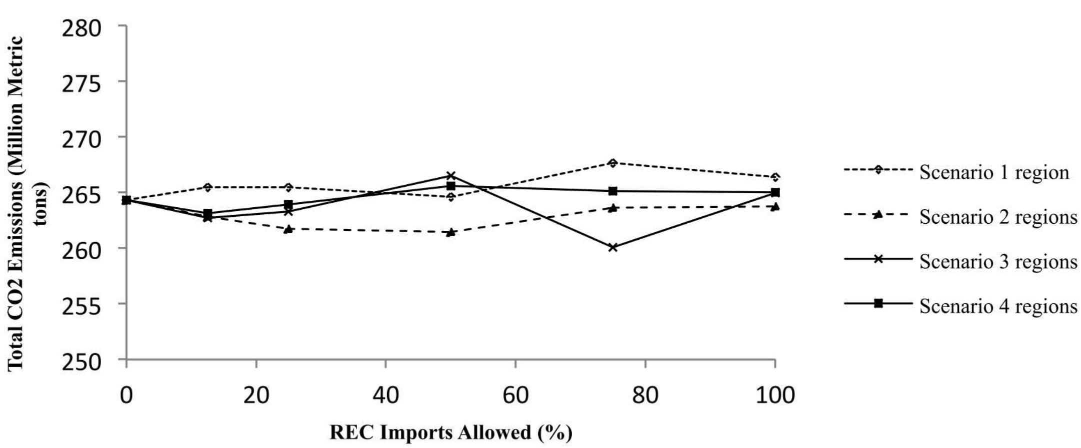

Consistent with Munoz et al. (2013a), we also observe that the set of lines constructed under low levels of trading flexibility is not necessarily a subset of the lines that are selected under higher levels of trading flexibility. For instance, the transmission reinforcements selected for 25% of REC trading flexibility in California are not all built in the 50% or 75% cases. This suggest 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 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.[9] Intuitively, a state that chooses to import renewable certificates makes up for that power with either local or imported conventional generation. This leads to an increase in local $CO_2$ and other emissions. However, this 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 certificate trading impacts aggregate emissions.

Figure 7 shows the total amount of WECC $CO_2$ emissions as a function of the allowed percentage of 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 1.6% with respect to the baseline scenario where no trading is allowed. Allowing for 100% of certificate trading among states, in the 1-Region scenario, only increases aggregate emissions levels by 0.8% 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.[10]

**Figure 7:** Aggregate WECC $CO_2$ emissions as a function of the REC trading allowed.




[9] As discussed by Bushnell et al. (2008), these environmental 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.

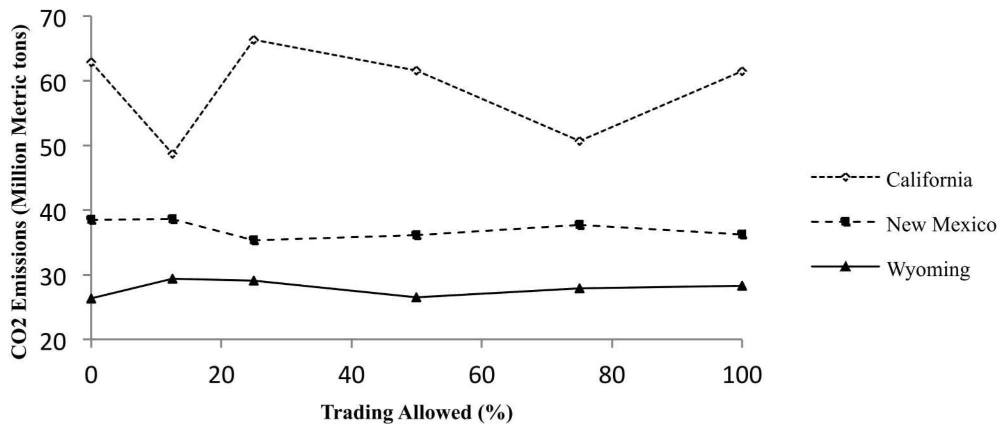
[10] There exist concerns that increasing penetrations of intermittent generation could increase emissions levels due to more frequent cycling, steeper ramps, and partially-loading of conventional generators. However, Lew et al. (2012) find that accounting for these features in production cost models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

Figure 8 shows the amount of $CO_2$ emissions in three states of the WECC as a function of the percentage of REC trading allowed. We find that the non-monotonic behavior of 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 REC imports allowed increases from 0% to 12.5% and from 50% to 75%, accompanied by an increase in transmission investment in the same ranges (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 REC trading flexibility from 0 to 12.5% 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 0% to 12.5% yields $CO_2$ emissions reductions of 22.5% in the state (see Figure 8). In turn, the economic conditions that result from increasing imports further from 12.5% to 25% turn out to not justify the addition of more transmission in California. Indeed, transmission investment falls. As a result, $CO_2$ emissions grow by 36.6% in the state due to increase in-state conventional generation. In summary, the effect of increased flexibility on certificate trading leads to ambiguous changes in $CO_2$ emissions by state.[11]

In the case of New Mexico, wind and solar power generation increase when REC import limits are increased, making New Mexico a REC-exporting state. We find that $CO_2$ emissions in the state decrease by 8.3% when trading flexibility is increased from 0% to 25% 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 imports further, from 25% to 100%, coal generation increases and gas generation remains constant, which causes an increase in $CO_2$ emissions. This yields a modest 5.9% net reduction of the state's emissions with respect to the scheme where no trading is allowed (i.e., 100% vs. 0% limit on REC imports).

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

**Figure 8:** $CO_2$ emissions per state in the 1-Region scenario.

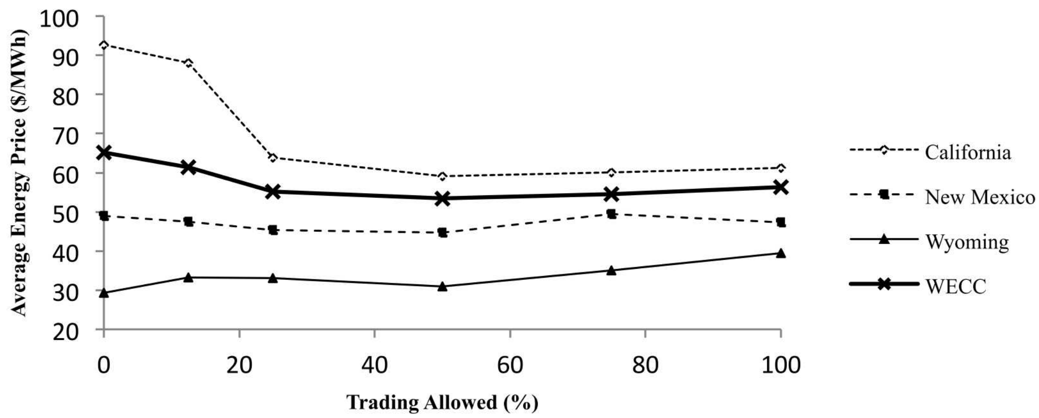



The state of Wyoming, on the other hand, does not have an RPS obligation, but when certificate trading is allowed, REC prices incent investment in solar and wind generation. Wyoming transmission investment increases as the amount of REC imports allowed by other states increases from 0% to 12.5% and from 50% to 75% (Figure 6). And recall that in California, we observed 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 increase over the same ranges of allowed REC imports (Figure 8), which highlights the unpredictability of the relationship between transmission investments and $CO_2$ emissions.

**5.6. Energy Prices**

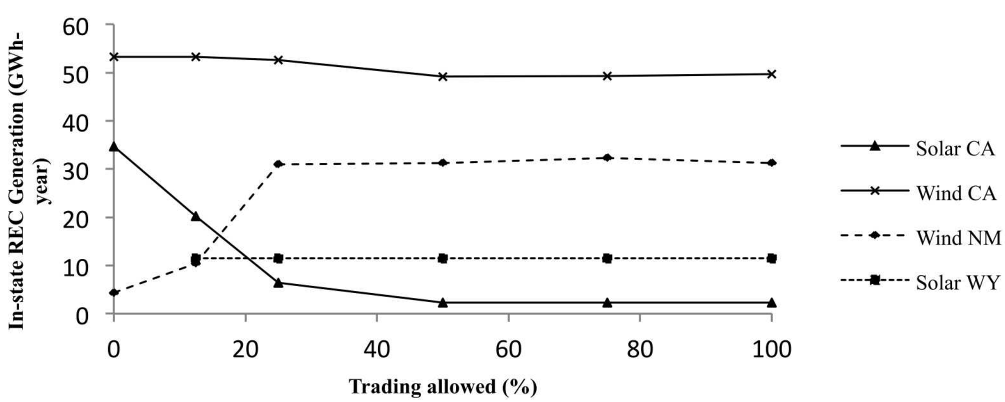
Figure 9 shows the long-run average energy price in the WECC and in a sample of states as a function of the REC imports allowed for the 1-Region scenario. Results are similar for the other three geographic restriction scenarios. The average energy price in each state is computed by weighting nodal energy 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 node, accounting for effects on energy balance constraints, reserve margin requirement constraints, and RPS constraints.

**Figure 9:** Average energy prices in the WECC and per state in the 1-Region scenario.




We find that increasing REC trading flexibility from 0% to 100% reduces average energy price in the WECC by 13.6%. This decrease is greater than the decrease in total cost (10.8%, 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 33.9% as more REC trading is allowed. On the other hand, energy prices tend to increase in the state of Wyoming. To help explain these differences, Figure 10 presents the in-state REC generation as a function of the REC trading allowed, in the 1-Region scenario.

**Figure 10:** In-state REC generation by technology and state, 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 increase of average energy prices in Wyoming (a REC-exporting state) is a result of higher amounts of solar generation as more trading is allowed. At the same time, more flexibility also leads to a more intensive use of coal power plants in Wyoming (transferring $CO_2$ emissions from California to Wyoming and other states), which also contributes to an increase of the average energy price (34.5% increase as allowed REC imports elsewhere increase from 0% to 100%). Meanwhile, in New Mexico, average energy prices stay relatively constant as the RPS policies become more flexible. This is because this REC-exporting state generates RECs mainly from cost-effective wind and biomass resources.

## 6. Conclusions and Policy Implications

We quantify the benefits of allowing increased trade of RECs among western U.S. states in order to meet state RPSs. 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 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 RECs are approximately $3.9 Billion per year, compared to the situation where no interstate trading is allowed. These cost savings correspond to a 10.8% reduction in generation variable cost and annualized cost of new generation and transmission. Remarkably, 90% of these economic gains can be captured by increasing the allowed REC imports from 0% to 25%, assuming that trade is restricted to either 1 west-wide zone, or 2 or 3 subregions of WECC. The gains are less if the REC market is further fragmented into four exclusive zones. Increasing trading flexibility beyond 25% results in further, but much more modest, cost reductions. This trend is mirrored in the redistribution of generation investments among different renewable energy technologies, which tend to stabilize together with total system cost once the in-state constraint is expanded beyond 25%.

In addition, in the 1-Region scenario, when 25% of REC imports are allowed three states have a biding RPS constraint while four states have a biding RPS constraint with 50% of REC imports allowed. In contrast, in the 4-Regions scenario, five states have a biding RPS constraint when 25% of REC imports are allowed. This suggests that defining adequate geographic restrictions may influence the in-state commitment with the RPS's target while still reaching important cost savings.

We also find that increasing REC trading flexibility does not necessarily imply an increase in transmission investment cost, contrary to the suggestion by Vajjhala et al. (2008). Transmission investments in some policy scenarios are double those in others, but the scenarios with the most 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) the lumpy characteristic of transmission infrastructure. 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 an isolated manner (Liu et al., 2013).

Similarly, our simulations show that increased REC trading flexibility does not have a significant impact on $CO_2$ emissions—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 certificate trading flexibility is minimal, although emissions in California could be reduced significantly for some specific levels of REC imports allowed. However, if efficient 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 33.9% as trading flexibility is increased. In contrast, energy prices in Wyoming tend to increase as the RPS policies become more flexible. This is mainly due to an increase in demand for that state's solar and coal generation as more REC trading is allowed; demand for coal generation increases as a byproduct of building more transmission.

We also emulate the geographical restrictions that some states impose on the eligibility of RECs through four different scenarios regarding which states are allowed to trade with each other. Our results show that the loss of economic efficiency of a 2- or 3-Region scenario is relatively small compared to a WECC-wide market for RECs (1-Region). But a 4-Region scenario would change investments and costs more significantly. 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, Colorado and New Mexico. Therefore, although only a small amount of REC import flexibility (25% out-of-state limit) is needed to capture a large fraction of the gains from REC trading, geographical constraints on the eligibility of RECs could reduce those savings if geographical constraints are myopically defined (e.g., LSEs in California limited to purchasing RECs only from neighboring states).

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 from technologies such as natural gas, nuclear power, and energy efficiency measures.

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## Appendix: 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). |
| $\Omega_l$ | 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]. |
| $\alpha$ | Fraction of RPS that must be generated from each state. |
| $\delta$ | 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 $l$. |