Exploration of Resource and Transmission Expansion Decisions in the Western Renewable Energy Zone Initiative

Andrew Mills,* Amol Phadke, and Ryan Wiser

Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley, California 94720-8136

Abstract

The Western Renewable Energy Zone (WREZ) initiative brings together a diverse set of voices to develop data, tools, and a unique forum for coordinating transmission expansion in the Western Interconnection. In this paper we use a new tool developed in the WREZ initiative to evaluate possible renewable resource selection and transmission expansion decisions. We evaluate these decisions under a number of alternative future scenarios centered on meeting 33% of the annual load in the Western Interconnection with new renewable resources located within WREZ-identified resource hubs. Our analysis finds that wind energy is the largest source of renewable energy procured to meet the 33% RE target across nearly all scenarios analyzed (38-65%). Solar energy is almost always the second largest source (14-41%). We find several load zones where wind energy is the least cost resource under a wide range of sensitivity scenarios. Load zones in the Southwest, on the other hand, are found to switch between wind and solar, and therefore to vary transmission expansion decisions, depending on uncertainties and policies that affect the relative economics of each renewable option. Further, we find that even with total transmission expenditures of $17-34 billion these costs still represent just 10-19% of the total delivered cost of renewable energy.

Keywords: Renewable electricity, Proactive transmission planning, Valuation

1. Introduction

Building transmission to reach renewable energy goals requires coordination among renewable developers, utilities and transmission owners, resource and transmission planners, state and federal regulators, and environmental organizations. The Western Renewable Energy Zone (WREZ) initiative brings together a diverse set of voices to develop data, tools, and a unique forum for coordinating transmission expansion in the Western Interconnection. One product of the WREZ process is a transparent, Excel-based tool developed by Black & Veatch, Lawrence Berkeley National Laboratory, and numerous Western resource and transmission experts (the WREZ

* Corresponding Author: ADMills@lbl.gov; ph: +1 510 486 4059

model). The tool allows any load zone in the Western Interconnection to answer basic questions about which renewable resources might be most attractive to that load zone and what transmission might be needed to access those resources. The value of a screening tool like the WREZ model is that is allows fast, simple evaluation of several "what-if" scenarios. Evaluation of several scenarios can help identify the importance of different sources of uncertainty and the impact of policy decisions on renewable resource selection, transmission expansion, and overall costs.

In this paper, we use the WREZ model to evaluate west-wide and load zone specific renewable resource selection and transmission expansion decisions across a large number of different assumptions. These cases are centered on a scenario in which each load zone in the Western Interconnection procures incremental renewable resources identified in WREZ resource hubs sufficient to provide 33% of each load zone's annual energy demand for a target year of 2029. WREZ resource hubs are environmentally preferred locations of high quality renewable resources that include sufficient renewable energy supply to potentially justify building a new 500 kV transmission line delivering roughly 1,500 MW of new transfer capacity.

Our analysis in this paper, which presents select results of a larger study by Mills et al. (2010), assumes that only the resources identified in the WREZ hubs are used to meet renewable energy targets. Significant renewable resource potential also exists outside of the WREZ hubs, but we do not evaluate non-WREZ resources. The results of the analysis presented here therefore reflect the transmission and resource selection that might occur if WREZ resource hubs were to be the primary source of renewable energy to meet aggressive targets by 2029. Because these results exclude non-WREZ resources, they likely overstate the need for new transmission investment; future analysis should evaluate the possible attractiveness of non-WREZ resources compared to the WREZ resources considered here. Moreover, because we use a high-level screening tool and abstract from existing state renewable energy policy requirements, specific resource procurement decisions and transmission lines cannot be justified or rejected by this analysis alone. Where our analysis identifies that transmission and resource procurement decisions vary significantly with assumptions, however, it is important that the more detailed analysis of specific resources and transmission explicitly evaluate these assumptions in more detail.

This paper provides a clear framework for identifying relative economic attractiveness of renewable energy to loads based on estimates of delivered cost and market value. It is also the first to use the WREZ data and model to identify the resource selection, transmission expansion, and costs required to access WREZ resources under several different renewable energy procurement, technology cost, transmission, and policy scenarios. No comprehensive analysis of the sensitivity of transmission investments for renewable energy to different assumptions and policies is available in the literature.

This analysis does, however, build upon a wide range of earlier studies that have evaluated transmission planning in the western United States for renewable energy. The Clean and Diversified Energy Advisory Committee (CDEAC), for example, evaluated the transmission needed to reach a 2015 goal of 30,000 megawatts (MW) of "clean and diversified energy" in the West (CDEAC, 2006). In contrast to the WREZ model, the resources and transmission selected in the CDEAC cases were based on expert opinion and recommendations from resource task forces. The selected resources were then evaluated in an advanced production cost model. The Wind Deployment System (WinDS)[1] was used in the DOE/NREL/American Wind Energy Association (AWEA) "20% wind by 2030" analysis to identify the optimal sites and transmission expansion in the United States to meet a target of 20% wind energy by 2030 (U.S. DOE, 2008). A similar model, the Concentrating Solar Deployment System (CSDS), was used to estimate the transmission needs for deployment of solar thermal in the southwest United States with and without the availability of federal incentives (Blair et al., 2008). General Electric (GE) developed a screening analysis to pair resources and loads in its site selection algorithm[2] for the *Western Wind and Solar Integration Study* (Lew et al., 2009). Instead of focusing on determining where to site one renewable technology at a time, the WREZ model selects between five different renewable technologies identified in WREZ hubs (wind, solar, geothermal, biomass, and hydropower). Finally, Olson *et al.* (2009) used resource data from resources in the Western Interconnection to evaluate the benefits of new long-distance transmission to meet renewables portfolio standard (RPS) and greenhouse gas (GHG) goals in the Western Interconnection. Our study differs from Olson *et al.* largely in methods (particularly our market valuation adjustments) and resources included in the analysis (we focus only on WREZ renewable resources).

The remainder of this paper is organized as follows. In Section 2 we present an overview of the method used in the WREZ model to broadly account for the differences in bus-bar costs, transmission costs, and market value of different renewable resources, and to rank those resources from the perspective of a load zone in the Western Electricity Coordinating Council (WECC). In Section 3 we examine the relative economic attractiveness of WREZ resources, the transmission required to access those resources, and the costs of the resources for several different renewable energy expansion scenarios within the Western Interconnection. These expansion scenarios include incremental WREZ resource procurement targets to meet 12%, 25%, and 33% of the annual energy demand in the WECC with new RE for a target year of 2029. The 33% RE scenario is then evaluated under a number of different assumptions about transmission, technology options, resource costs, availability of federal tax incentives, and acceptance of renewable energy credits (RECs). Conclusions are offered in Section 4.

1. Methodology

The generation and transmission model developed for the WREZ initiative enables users to evaluate the relative economic attractiveness of any of the renewable resources in fifty-five WREZ hubs to any of the twenty load zones in the WECC. In addition, a user can assess the economic attractiveness of resources from the perspective of any other load zone to evaluate the potential for collaboration in building transmission lines to access the resources or the potential competition among loads for limited, high-quality renewable resources. The relative economic attractiveness of a resource to any load zone in the WREZ model is measured by a metric called the *adjusted delivered cost* (ADC). The ADC is the delivered cost of a resource to a load zone considering bus-bar and transmission costs, adjusted for key market value adjustment factors, and is reported in dollars per megawatt-hour ($/MWh) terms. Market value adjustments are applied to compare, at a screening level, technologies that have different generation characteristics and therefore different values to the electricity system.

More specifically, the WREZ model defines the simple (unadjusted) delivered cost as the generation (or bus-bar cost) of a resource plus the cost of transmission and line losses to deliver the electricity produced by that renewable resource to a particular load zone. To produce the ADC, three market value adjustment factors are considered: (1) integration costs, (2) avoided resource adequacy costs, and (3) avoided time-of-delivery energy costs. *Integration costs*—the costs of accommodating the uncertainty and variability of variable resources, such as wind and solar without thermal storage—are added to the delivered cost. *Avoided resource adequacy costs*— which represent the contribution of a renewable resource toward resource adequacy needs (the capacity value)—are subtracted from the delivered cost. Finally, *avoided time-of-delivery energy costs*—which are due to the time dependent energy costs displaced by electricity from a renewable resource (the time-of-delivery [TOD] energy value)—are subtracted from the delivered cost. Figure 1 illustrates this calculation framework, and provides a representative case that demonstrates how the relative economic attractiveness of resources can shift as each of these economic drivers is considered. For example, solar resources become more attractive when market value adjustment factors are considered because these resources have a higher TOD energy value and contribute more toward resource adequacy for the load zone considered in the figure, compared to wind resources. Each of these factors is discussed in more detail below.

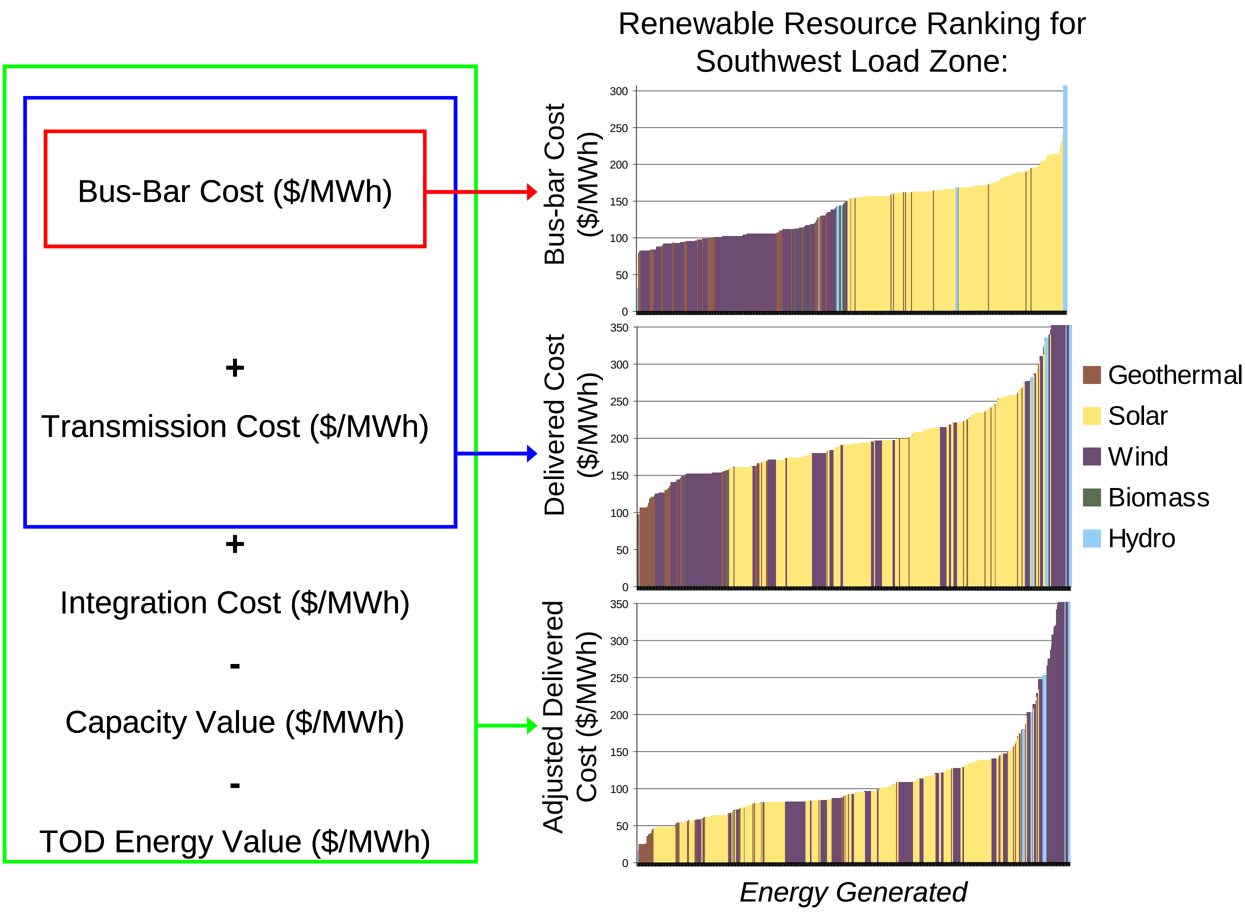


Figure 1. Framework for evaluating the economic attractiveness of renewable resources to load zones in the WREZ model

2.1 Bus-bar Costs

Bus-bar costs are defined as the cost of delivering the resulting electricity to the nearest transmission system substation, and are derived from a simple levelized-cost-of-energy model developed by the Zone Identification and Technical Analysis group (ZITA) and Black & Veatch within the WREZ process (Pletka and Finn, 2009). Bus-bar costs depend on the assumed capital and operating cost of the generation facility, the cost of building a new generation tie-line from the middle of the resource region to the nearest transmission substation, the capacity factor of the renewable resource, and financing parameters—including the capital structure, cost of debt and equity, and tax rates. ZITA and Black & Veatch developed these various input parameters, and the core results presented in this paper rely upon those assumptions. One important assumption was that the debt term of the solar technologies is 25 years while the debt term of all other renewable technologies is 15 years. We test the relative importance of this assumption in Section 3. A summary of a subset of these various input parameters, as well as the resulting bus-bar costs, is provided in Table 1. The range in capital cost, capacity factor, and bus-bar costs reported in Table 1 within any individual renewable resource type reflect ZITA and Black & Veatch assumptions about variations in cost drivers across renewable resource sites.

Table 1. Range of capital costs, capacity factors, and bus-bar costs based on starting point assumptions in the WREZ model

Renewable Technology	Total Capital Cost ($/kW)		Capacity Factor		Bus-Bar Cost with Starting Point Assumptions ($/MWh)	
	Energy-Weighted Median	(10th; 90th Percentile)	Energy-Weighted Median	(10th; 90th Percentile)	Energy-Weighted Median	(10th; 90th Percentile)
Hydro	4,263	(1,106 ; 9,818)	50%	(39% ; 51%)	128	(27 ; 376)
Biomass	3,659	(3,515 ; 3,824)	85%	(85% ; 85%)	115	(109 ; 147)
Geothermal	5,064	(4,355 ; 5,901)	80%	(80% ; 90%)	92	(78 ; 108)
Wind	2,418	(2,396 ; 2,469)	31%	(28% ; 39%)	92	(73 ; 121)
Wet Cooled Solar Thermal with Storage	7,473	(7,465 ; 7,556)	38%	(30% ; 40%)	163	(155 ; 193)
Wet Cooled Solar Thermal without Storage	5,174	(5,165 ; 5,352)	27%	(21% ; 29%)	169	(161 ; 212)
Dry Cooled Solar Thermal with Storage	7,674	(7,665 ; 7,756)	36%	(29% ; 37%)	175	(170 ; 201)
Fixed PV	4,576	(4,565 ; 4,690)	25%	(22% ; 26%)	156	(150 ; 179)

2.2 Transmission Investment, Operations, and Line Losses Cost

All renewable resources in the WREZ model are assumed to require new transmission capacity between the interconnection point of the renewable resource and the load zone that procures the resource. Because the WREZ effort is primarily focused on large additions of new renewable generation in concentrated, high-quality resource zones, this assumption, while conservative, is reasonable. Nonetheless, this assumption may lead to an overestimate of the cost new renewable generation because: (1) some portion of these resources might rely on existing transmission capacity, and (2) there are renewable resources that were not identified in the WREZ process that may not require new transmission capacity. Additionally, assigning the full cost of transmission capacity to new renewable resources assumes that the transmission investment does not offset any other transmission upgrades that would otherwise be required for reliability reasons.

The transmission costs assigned to renewable resources are based on a pro-rata share of the new incremental transmission investments between the resource hub and a load zone. The pro-rata share is allocated using the nameplate capacity of the renewable resource. The assumption that renewable generators only pay a pro-rata share of new transmission capacity may understate costs due to the fact that 500 kV transmission lines can only be built in discrete increments (i.e., transmission investments are "lumpy"). The pro-rata transmission allocation assumption ignores the lumpiness of transmission by assuming that a transmission line is always fully subscribed.[3] In checking the reasonableness of the pro-rata allocation assumption, we find that 89% to 99% of the new renewable capacity procured from each state or province for each individual load zone would be sufficient to reserve two-thirds or more of the transmission capacity added in the 33% RE demand cases presented later. In other words, most load zones procure at least 1000 MW of new renewable resources within a state over the assumed 1500 MW, 500 kV lines. Cooperative transmission investments by multiple load zones, and use of available transmission by non-renewable resources, would further increase line subscription. Ignoring the lumpiness of transmission for the present analysis is therefore not unreasonable.

2.3 Market Value Adjustment Factors

To enable comparisons among renewable resources that have widely varying electrical output characteristics, the delivered cost of renewable energy is adjusted to account for the market value of difference resource-load zone pairs. These market value adjustment factors include TOD energy value, capacity value, and integration costs, Table 2.[4] The market value adjustment factors applied here are indicative of the cost and value of adding renewable energy to power systems at low to moderate levels of renewable energy penetration. Though the market value of renewable energy will tend to decrease with increased penetration, we do not alter the three market value adjustment factors with penetration in the WREZ model. Though clearly a simplification this assumption is not unreasonable in a screening-level assessment; nonetheless, changes in the market value of renewable energy with increased penetration, particularly the TOD energy and capacity value, deserves attention in more detailed analyses.

2.3.1 Time-of-Delivery Energy Value

The time-of-delivery energy value of a resource reflects the avoided fuel and operating cost from conventional generation plants that are used less frequently with the addition of renewable energy. Because these fuel and operating costs vary seasonally and diurnally, and because the generation profile of renewable energy varies by technology and resource location, the avoided energy cost must be considered based on the correlation of renewable energy generation profiles with periods in which the marginal production cost in the power system is high. Moreover, because marginal production costs vary by load zone, the TOD energy value of a particular renewable resource will vary based on the load zone to which it is delivered.

The TOD energy value of a resource-load zone pair is calculated as shown in Equation 1, while the *TOD energy factor* is simply defined as the ratio of the TOD energy value to the annual average marginal production cost.

$$\text{TOD Energy Value (\$/MWh)} = \frac{\sum \text{Energy Generated (MWh)} \cdot \text{Marginal Production Cost (\$/MWh)}}{\text{Annual Energy Generation (MWh/yr)}}$$

Equation 1

The better correlated a resource generation profile is with marginal production costs, the higher its TOD energy value will be. Solar energy, which tends to generate more power during periods of high demand for electricity, has a relatively high TOD energy value compared to resources with generation profiles that are largely uncorrelated with demand, such as wind (Grubb, 1991; Hirst and Hild, 2004; Borenstein 2005, 2008; DeCarolis and Keith, 2006; Denholm et al., 2009; Fripp and Wiser, 2008; Lamont, 2008). The marginal production costs used in the WREZ model are derived from a production cost model run of the WECC region using the production cost model (PROMOD). Hourly, location-based marginal production costs from the PROMOD run were converted into twelve-month by twenty-four-hour average marginal production costs (12 X 24). Similarly, ZITA developed 12 X 24 generation profiles for each renewable resource type at each WREZ hub.

2.3.2 Capacity Value

Because the TOD energy value is based only on marginal production costs, a resource that provides significant capacity will be undervalued with the TOD energy value alone. In real energy markets, prices rise above marginal production costs during peak periods, allowing generation facilities to recover fixed costs, or else revenues are augmented with a capacity market payment that is separate from and additional to the energy payment.

We capture the capacity value of renewable resources as the avoided cost of the alternative resource that would otherwise be used to meet resource adequacy needs, considering the capacity credit of the renewable resource. The avoided cost of the alternative resource used to meet resource adequacy needs is assumed to be the fixed cost of a new gas turbine peaker plant. As a starting point, we assume investor-owned utility (IOU) financing, a capital cost of $1,090/kW, and a fixed operation and maintenance (O&M) cost of $10/kW-yr. This yields a total levelized fixed cost of $156/kW-yr or $17.8/MW-h, which is used in our base case analyses; due to a wide variety of cost assumptions for peaker plants,[5] we test the sensitivity of our results to the capital cost of a peaker plant in an alternative sensitivity case.

The ability of variable renewable generation to contribute toward resource adequacy requirements (and therefore displace other capacity resources) has been studied in detail for wind (Milligan, 2000; Gross et al., 2006; Holttinen et al., 2009) and solar (Hoff et al., 2008, Lew et al., 2009). The capacity credit of resources ideally should be based on an evaluation of the effective load carrying capability (ELCC) of a resource using a probabilistic reliability analysis (Milligan and Porter, 2006). Since such an analysis would be too complex to perform for all resources in a screening level tool, we use the simple approximation that the capacity credit is the capacity factor of the renewable resource during the peak 10% of load hours for the load zone to which the resource is delivered. Though this is only an approximation of the capacity credit of a resource, Milligan (2000) indicates that such a method provides a reasonable estimate of capacity value based on a detailed comparison of various methods for calculating the capacity credit of wind. More specifically, the capacity credit of each resource-load pair is calculated in the model using the 12 X 24 average generation and load profiles.[6] Each renewable resource, therefore, receives a capacity credit for each load zone to which it could be delivered. The calculation of the capacity value on a per unit energy basis is shown in Equation 2, below:

$$\text{Capacity Value (\$/MWh)} = \text{Fixed Cost of Peaking Unit (\$/MW - h)} \cdot \frac{\text{Capacity Credit}}{\text{Capacity Factor}}$$

Equation 2

A key parameter in this relationship is the ratio of the capacity credit to the capacity factor. A baseload resource that has a flat generation profile at its rated nameplate capacity will receive a capacity credit of 100%, and it will have a capacity factor of 100%; the ratio for a baseload unit would therefore be about 1. A peaking unit, on the other hand, produces at its nameplate capacity only during periods of generation scarcity. It receives a 100% capacity credit, but its capacity factor may be only 10% or even lower in some cases. The ratio of the capacity credit to the capacity factor could then be 10 or higher for a peaking unit of this type. A wind plant with a generation profile that drops off during summer days, on the other hand, may receive a capacity credit of around 10% when delivered to a load zone with a summer peak. If the wind plant has an annual capacity factor of 35%, then this ratio is only 0.28, leading to a low capacity value. If the same wind plant were to deliver its power to a load zone with a winter night peaking load, such as in the Northwest, however, it may have a capacity credit of more than 35%, and the ratio of the capacity credit to the capacity factor would could increase to more than one, with the capacity value of the wind plant on a dollars per unit of energy basis being be similar to or potentially even higher than that of a baseload unit (Grubb, 1991; Stoft, 2008).

The solar technologies are found to have the highest capacity values, while the wind technologies have the lowest, on average. The relatively low ratio of the capacity credit to the capacity factor for many of the geothermal plants reflects the reduced output of these plants during periods of high temperatures, which in many locations correlates with periods of high load. For the median resource-load pair, solar technologies are found to be $13-29/MWh more valuable than wind energy, depending on the solar technology used, while baseload renewable technologies are found to be $4-8/MWh more valuable than wind, on average. Solar thermal technologies with thermal storage, based on capacity value alone, are roughly $8/MWh more valuable than solar thermal without storage, while fixed-plate PV is found to be $7/MWh less valuable than solar thermal plants that lack thermal storage, Table 2.

2.3.3 Integration Costs

Integration costs are meant to reflect any additional costs incurred to manage the variability and uncertainty of wind energy and solar technologies that lack thermal storage. A number of integration cost studies for wind have been conducted in the United States and Europe, and at least one balancing area in the United States charges a wind balancing tariff to manage the variability and unpredictability of wind (BPA, 2009). Wind integration costs in the U.S. are generally found to be less than $10/MWh and often less than $5/MWh for wind penetrations up to 30% on a capacity basis (Wiser and Bolinger, 2009). A recent wind integration study that evaluated up to 30% penetration of wind energy on an energy basis throughout the Eastern Interconnection estimated the integration costs to be $5/MWh (EnerNex Corp., 2010). Literature surveys that include results from European studies find similar results. Integration costs reported in one literature survey are estimated to be less than $10/MWh in 80% of studies, and often less than $6/MWh for penetrations up to and sometimes exceeding 20% on an energy basis (Gross et al., 2007). In another survey, integration costs were estimated to be less than $5/MWh for wind energy penetrations up to and sometimes exceeding 20% on an energy basis (Holttinen et al., 2009).[7] Relatively few studies have investigated the integration costs for solar technologies (U.S. DOE, forthcoming), though Mills and Wiser (forthcoming) find that these costs are likely to be similar to those for wind energy. Based on these findings, the starting point assumption for wind integration costs used in this study is $5/MWh. Integration costs for PV and solar thermal without thermal storage are more uncertain, and merit further study, but are assumed here to equal $2.5/MWh.

Table 2. Range of market value adjustment factors based on starting point assumptions in the WREZ model

	TOD Energy Value Assuming $65/MWh Average Marginal Production Cost ($/MWh)		Capacity Value Assuming $156/kW-yr Resource Adequacy Cost ($/MWh)		Integration Cost ($/MWh)	Market Value Adjustment ($/MWh)
Technology	Median	(10th; 90th Percentile)	Median	(10th; 90th Percentile)	Assumption	Median
Hydro	65.4	(60.9 ; 72.7)	21.7	(5.0 ; 35.4)	N/A	87.0
Biomass	65.0	(65.0 ; 65.0)	17.8	(17.8 ; 17.8)	N/A	82.8
Geothermal	64.4	(63.7 ; 65.0)	13.5	(11.1 ; 20.0)	N/A	77.9
Wind	63.4	(55.7 ; 70.8)	9.7	(5.8 ; 25.7)	5.0	68.1
Wet Cooled Solar Thermal with Storage	71.0	(69.5 ; 73.5)	38.5	(13.7 ; 43.7)	N/A	109.5
Wet Cooled Solar Thermal without Storage	69.0	(67.7 ; 71.4)	30.2	(8.8 ; 40.5)	2.5	96.7
Dry Cooled Solar Thermal with Storage	70.9	(69.4 ; 73.3)	36.1	(14.7 ; 41.3)	N/A	106.9
Fixed PV	68.3	(67.6 ; 70.3)	22.7	(15.6 ; 30.0)	2.5	88.5

2. Results

We use the WREZ model to determine what new WREZ resources might be procured by load zones within the WECC region to meet different renewable energy target levels assuming that loads meet these targets at expected minimum cost, and that the renewable energy demand must be entirely met with renewables resources located in WREZ-identified hubs. The renewable energy target, in this case, is abstracted from existing state renewables portfolio standards (RPS). We do not account for the many nuances of existing RPS policies across states such as variations in resource eligibility, resource set-asides or carve-outs, and local preference multipliers or in-state/region requirements. Instead, we posit several WECC-wide renewable energy demand levels, and allow the model to determine the best combination of renewable resources and transmission investments to meet those targets on a WECC-wide basis.

Because the total developable quantity of the most attractive WREZ resources is limited, we must allocate these resources to load zones in an equitable and plausible fashion. To do so, we assume that all load zones simultaneously act to procure renewable resources to meet their RE targets, that all load zones and resource developers act in a competitive manner, and that all load zones and renewable resource developers have perfect information about resource costs and renewable energy demand. Under these stringent conditions, the competitive process ensures that any individual renewable resource is allocated to the load zone that has the most economic benefit from its use. Moreover, basic micro-economics shows that this competitive solution to resource allocation is also the allocation that will minimize costs region-wide. As a result, we model this allocation procedure by simply solving for the resource allocation that minimizes costs on a WECC-wide basis, subject to the achievement of load-zone RE targets and given limited renewable resource quantities.

A key objective of this section is to assess the sensitivity of renewable resource composition, costs, and transmission expansion to various assumptions and input parameters. As such, the results of a large number of alternatives to a Base case are presented. We begin by exploring various RE target levels in which each load zone in the WECC is assumed to achieve 12%, 25%, and 33% of its aggregate demand with new WREZ-identified renewable resources. After conducting this assessment of three different RE target levels, we select the 33% case as the Base case to which all other scenarios are compared. Except for the cases with RECs, all other scenarios assume that each load zone meets its RE target with WREZ resources that are physically delivered to the load zone through new transmission investment. In considering a wide range of alternative scenarios to the Base case, summarized in Table 3, we focus on questions around transmission, market value adjustments, technology and capital costs, federal policies, and state policies. All of cases below, except the last two, assume that WREZ resources have to be physically delivered over new transmission lines such that each load zone meets the same RE target level. In the final two cases, however, we loosen this restriction and instead allow unbundled renewable energy credits (RECs) to be used to meet a WECC-wide RE target of 33%

Table 3. Alternative Scenarios to the Base Case

Category:	Case Name:	Question:
Sensitivity	HVDC Long Lines	What if lower unit cost HVDC lines[a] were used for long distance lines (>400 miles)?
	High Utilization	What if wind and solar are able to increase the utilization of new transmission to 60%?
	Short Lines	What if transmission expansion was limited to shorter lengths (<400 miles) between load zones and resource centers?
	No Federal ITC or PTC	What if the Federal 30% ITC and production tax credit (PTC) are not available?
	Low Resource Adequacy Cost	What if resource adequacy costs in the future are lower than assumed in the Base case (specifically, $100/kW-yr instead of $156/kW-yr)?
Solar Technology	Solar Thermal, Dry Cooling with Storage	What if all solar deployment comes from these alternative solar technologies instead of the Base case wet-cooled solar thermal with storage?
	Solar Thermal, Wet Cooling without Storage	
	Fixed PV	
Solar Cost	Equal Solar Finance	What if the solar technology had a debt term equal to the debt term of the other renewable technologies of 15 years rather than the 25 years assumed in the Base case?
	Low Cost Solar Thermal	What if the capital costs of the particular technology in each of these cases are 70% of today's cost, while none of the other renewable technologies experience cost reductions?
	Low Cost Fixed PV	
Wind	Low Cost Wind	
	High Wind Integration Cost	What if wind integration costs are assumed to be double that of the Base case ($10/MWh instead of $5/MWh)?
Renewable Energy Credits (RECs)	WECC RECs	What if loads are allowed to procure renewable energy in excess of the 33% target and sell RECs to loads that procure less renewables while still meeting a WECC-wide 33% RE target in aggregate?
	WECC RECs, with Limits	What is the impact of RECs if we limit load zones to meeting a maximum of 33% of annual load with any one RE technology and meeting at most 50% of annual load with any combination of renewable technologies?

[a] HVDC lines were assumed to have only two AC/DC terminals; one terminal at the resource hub and one at the load. The starting points cost of each 3000 MW terminal in the WREZ model is $250 million. We continued to allocate these costs on a pro-rata share to renewable resources

3.1 Impact of the Level of Renewable Energy Demand

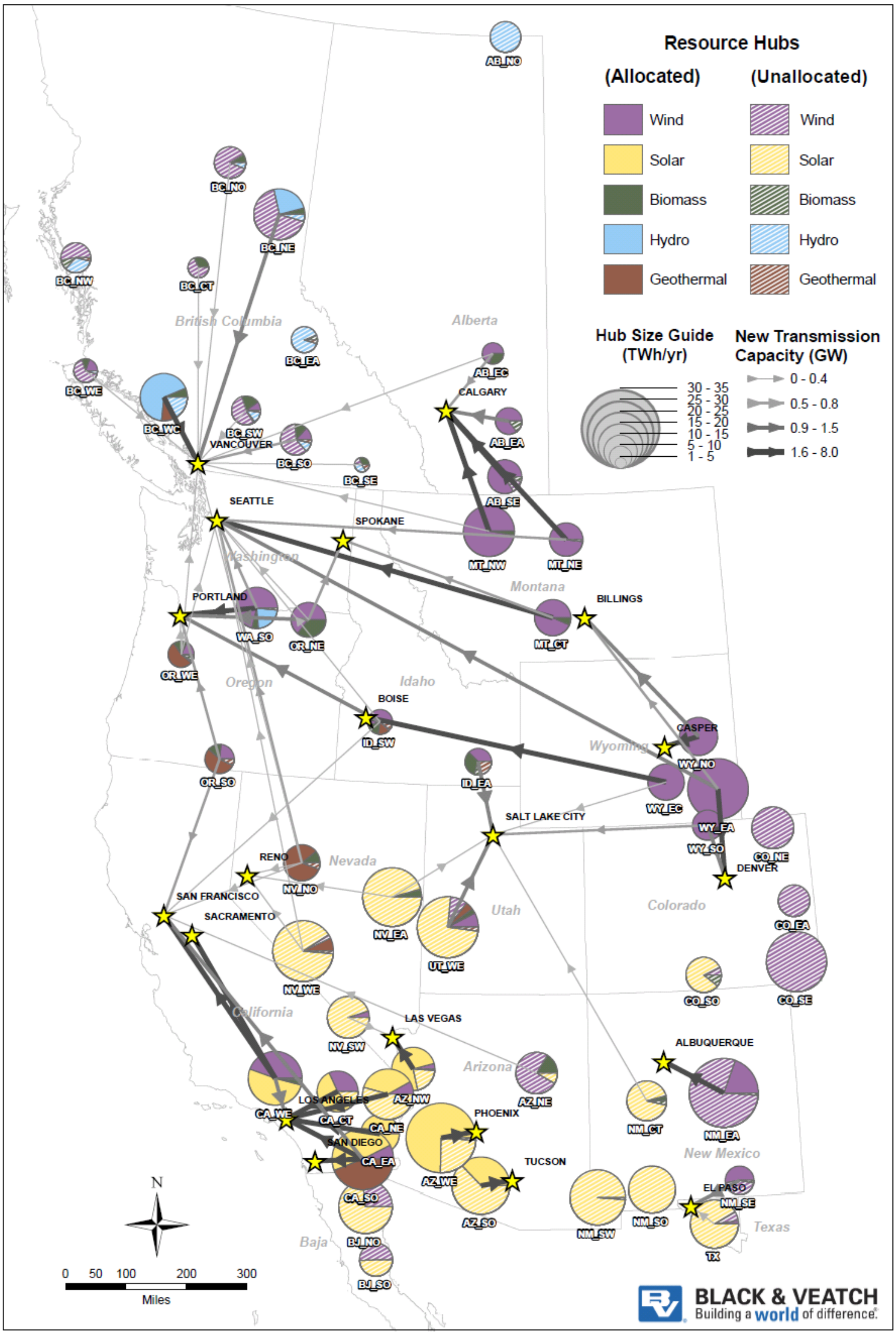
As shown in Table 4, we find that the largest source of additional supply when increasing renewable energy demand from 12% to 25% on a WECC-wide basis is wind energy, at least when relying on the WREZ starting point assumptions for the cost and performance of various renewable technologies. As the most attractive wind sites in the WREZ hubs are depleted, however, nearly equal amounts of solar and wind are added as renewable targets increase from 25% to 33% WECC-wide. Increasing the renewable target from 12% to 33% is found to increase the average cost of renewable energy supply by roughly $20/MWh. The average adjusted delivered cost represents the energy-weighted adjusted delivered cost of resources procured to meet the renewable energy demand WECC-wide. The marginal adjusted delivered costs, on the other hand, indicates the energy-weighted average cost of the resources that would be procured next by load zones if demand for renewable energy were increased a small amount. Regardless of the target level, new transmission costs total roughly 15% of total delivered costs.

Table 4. WECC-wide impact of increasing renewable energy levels on resource composition, costs, and transmission expansion

Impact		12% Renewables		25% Renewables		33% Renewables	
		(TWh/yr)	(GW)	(TWh/yr)	(GW)	(TWh/yr)	(GW)
Resource Composition	Geothermal	22.7	3.0	28.6	3.9	28.6	3.9
	Biomass	7.9	1.1	17.2	2.3	20.7	2.8
	Hydro	6.5	1.5	12.0	2.7	16.7	3.7
	Wind	42.2	13.2	108.5	36.1	144.3	48.2
	Solar	0.0	0.0	47.1	13.7	85.5	25.0
Costs	Average Adjusted Delivered Cost ($/MWh)	23.6		37.2		43.2	
	Marginal Adjusted Delivered Cost ($/MWh)	33.9		54.7		61.5	
Transmission Expansion	New Capacity (GW-mi)	4,123		11,958		18,510	
	Transmission Investment ($ Billion)	5.9		17.0		26.3	
	Transmission and Losses Cost as Percentage of Delivered Cost	16%		14%		15%	

3.2 Base Case: WECC-wide 33% RE with Energy Delivered to Each Load Zone

We next focus on the 33% WECC-wide renewable energy target. Under Base case assumptions, the incremental renewable resources procured from WREZ hubs by each load zone and the required transmission expansion to meet this 33% RE target are illustrated in Figure 2. These results illustrate the least-cost procurement of WREZ resources. Because the results do not consider a number of other factors that are assessed when analyzing specific resource procurement and transmission expansion decisions, specific projects cannot be justified or rejected by this analysis alone.



Map created 11/03/2009 by Sally Maki and Josh Finn

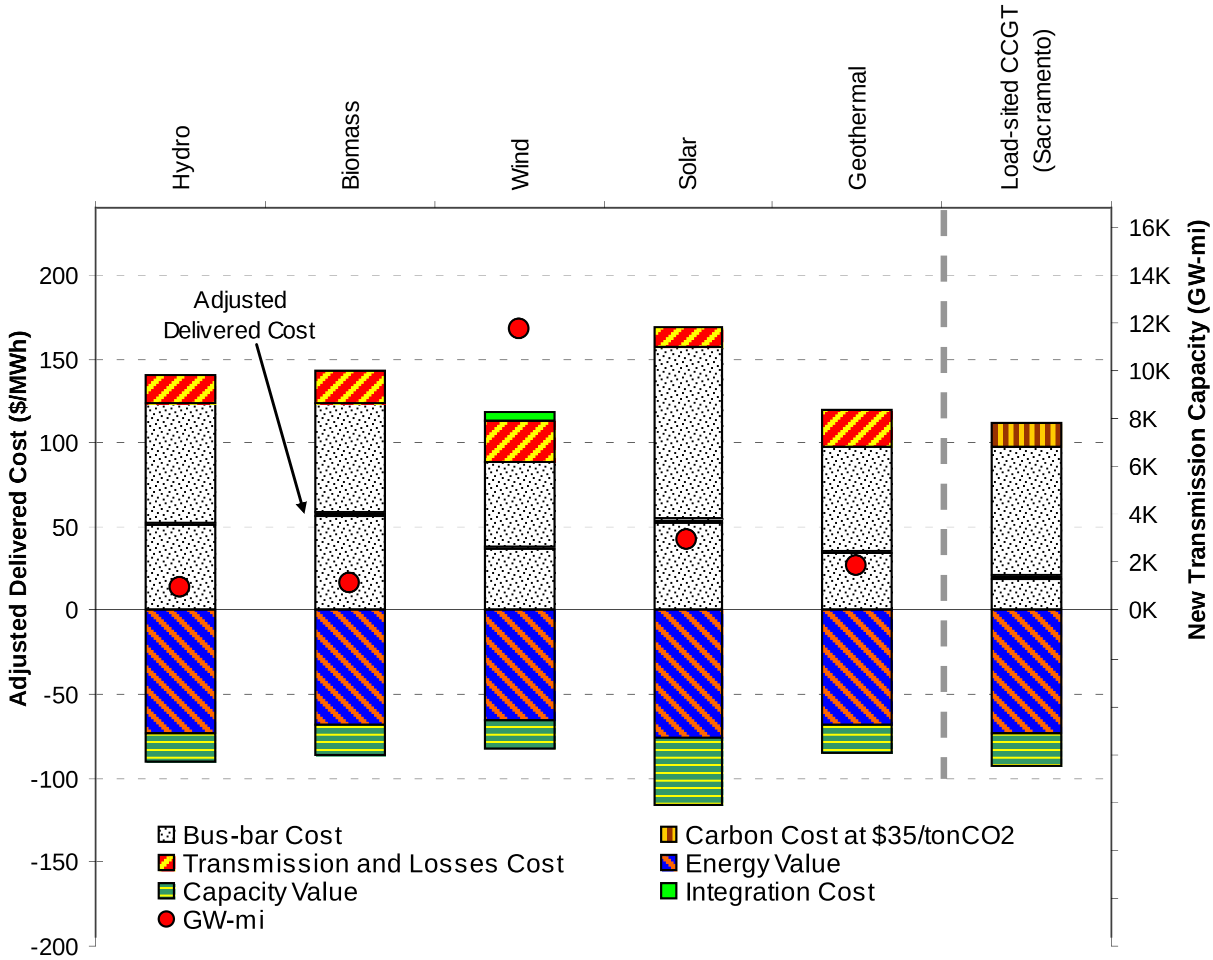
Note: The size of the WREZ hub reflects the total resource potential. The portion that is filled-in represents the resource that is procured by a load zone.

Figure 2. Transmission and resource selection in the WECC-wide 33% Base case

A significant portion (49%) of the incremental renewable energy is found to be wind energy, leading to a WECC-wide wind penetration of 16% on an energy basis. Wind penetration levels in a number of the individual load zones, however, particularly in the Pacific Northwest and Rocky Mountain region, approach the full 33% level, on an energy basis. Nine of the 20 load zones are found to select 100% wind energy to meet their 33% RE target, when constrained to purchase only from WREZ-identified renewable energy resource hubs. The large procurement of wind energy with the starting point assumptions is driven in part by its low bus-bar costs.

Solar, which has a higher bus-bar cost, is still procured by load zones near high-quality solar resources and far from large high-quality wind resources due to its favorable market value adjustment factors in some regions. The degree of correlation between solar generation and load in regions that select solar leads to the highest TOD energy and capacity value. In the Base case, only loads in Arizona, Nevada, and California rely on solar energy to meet the 33% RE target under the Base case assumptions. Overall solar is the second largest renewable resource type in the Base case and makes up 29% of incremental renewable energy demand. The WECC-wide solar energy penetration level is 8%.

Figure 3 presents the average cost and value components of the adjusted delivered cost for each technology based on the resources found to be procured to meet the 33% RE target in the Base case. For comparison, the cost and value components of a baseload CCGT are presented as well. Even wind energy receives considerable TOD energy and capacity value per unit of wind energy produced, though these values in aggregate are $34/MWh lower than the average value of solar energy.



Note: The cost and value components of a load-sited combined-cycle gas turbine (CCGT) in Sacramento assuming an $8/MMBTU natural gas price and a carbon cost adder are provided for reference.

Figure 3. Average cost and value components of the adjusted delivered cost for the various RE technologies and required transmission expansion in the Base case.

3.3 Alternative 33% RE Scenarios

Because of the wide range of uncertainties involved, we examined the robustness of the Base case results to many factors including changes in assumptions regarding transmission costs, availability of federal tax incentives, and renewable resource costs. The modeled change in the composition of the renewable resources procured across these various scenarios is shown in Figure 4.

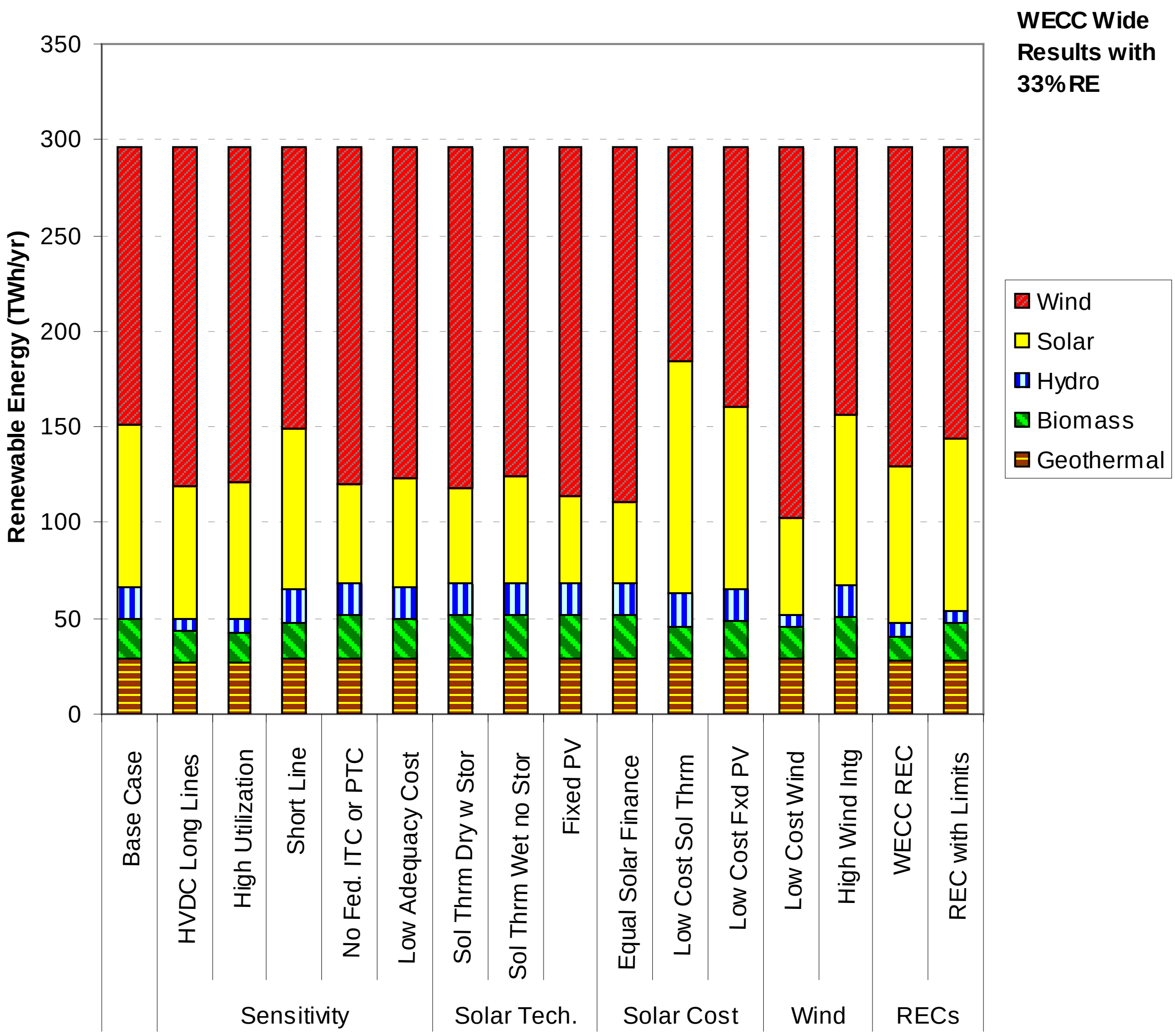


Figure 4. Resource composition relative to the Base case for several different 33% RE scenarios

Almost regardless of the scenario modeled, we find that wind energy is the largest contributor to meeting a 33% WECC-wide renewable energy target when only resources from WREZ hubs are considered. Across the 33% renewable energy target scenarios modeled here, wind energy constitutes 38-65% of incremental renewable energy demand. Solar energy is the second largest resource, providing 14-41% of the incremental renewable energy depending on the scenario in question. No matter what changes were made to key assumptions, wind energy was consistently found to be the most-economic resource choice in a number of load zones in the Northwest.

Though wind and solar increase significantly with increasing renewable energy targets, we found that the contributions of hydropower, biomass, and geothermal do not change significantly with increasing renewable demand. A large portion of these resources are procured at the 12% renewable energy level but, as renewable demand increases by 270% from the 12% case to the 33% case, the contribution of hydropower, biomass, and geothermal increase by only 78%. A primary reason for the limited change in procurement from these resources is their limited quantity in the WREZ resource database. The Base case 33% scenario utilizes 81% of the total available hydropower, biomass, and geothermal resource, while it only utilizes 54% and 31% of the available wind and solar resource, respectively. The entire geothermal resource characterized in the WREZ resource hubs is fully utilized across almost all of the 33% scenarios. The contribution of hydropower, biomass, and geothermal to meeting the 33% targets was therefore within a narrow range of 16-23% of the total incremental renewable energy target.

In contrast to the relative insensitivity of geothermal, hydropower, and biomass supply to the various scenarios modeled here, we find that key uncertainties can shift the balance between wind and solar in the renewable resource portfolio. The most dramatic flips in resource portfolios under different cases occur in regions that are near high-quality solar resources and where high-quality wind resources are either limited or distant. We find that increased quantities of wind are procured when wind costs are low, transmission costs are low, resource adequacy costs are low, or federal tax incentives for renewable energy are allowed to expire. Assumptions about the choice of solar technology and solar financing are also important considerations for determining the amount of wind that is procured. More solar is procured, on the other hand, when transmission expansion is limited, wind integration costs are assumed to be higher, or solar capital costs decline. By far, the most important uncertainty that increases the contribution of solar is the degree to which solar capital costs decline relative to other renewable technologies. The factors that affect the balance between wind and solar in resource portfolios should be explicitly considered in alternative transmission planning scenarios.

The impact of the different modeled 33% renewable energy scenarios on renewable energy supply costs and transmission expansion relative to the Base case is illustrated in Figure 5. Over the factors that most influence the costs are the availability of federal incentives and potential reductions in renewable capital costs. The elimination of 30% ITC, not surprisingly, dramatically increases the cost of RE in the WECC region: the average increase in costs is approximately $32/MWh. Because solar is more capital intensive than wind, solar benefits more from the 30% ITC. This larger benefit for solar, and the fact that solar it is often found to be the marginal resource for load zones seeking to meet a 33% RE target, means that the impact of an elimination of the ITC on marginal costs are more significant—approximately $38/MWh in the No Federal ITC or PTC case. On the other hand, a cost reduction of solar thermal plants relative to all other renewable technologies of 30%, well within the range of projected cost reduction potential, is sufficient to considerably reduce the adjusted delivered cost of meeting a WECC-wide 33% target.

The total capital investment required for the new transmission capacity estimated by the model to be required to deliver renewable resources from the modeled resource areas to the load zones is approximately $26 billion in the Base case and ranges from $22-34 billion across the non-REC sensitivity scenarios. Two sensitivity cases related to transmission assumptions result in significant increases in total transmission expansion relative to the Base case: the HVDC Long Lines case and the High Utilization case. The increase in transmission in the HVDC Long Lines and the High Utilization cases is primarily due to the enhanced economic attractiveness of remotely-located wind resources, which are more dependent on new transmission than are the other resources considered in this analysis. Even with more transmission expansion, these two cases are lower cost relative to the Base case.

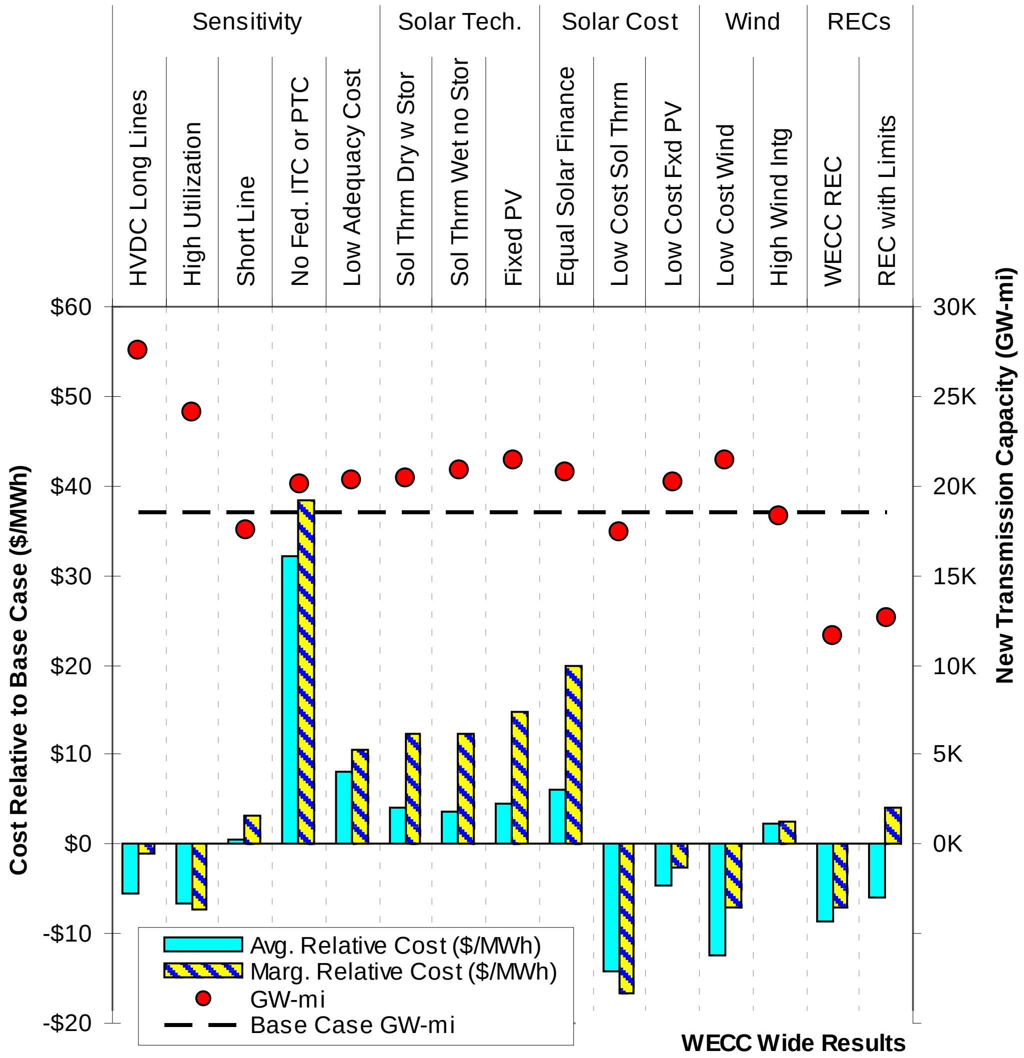
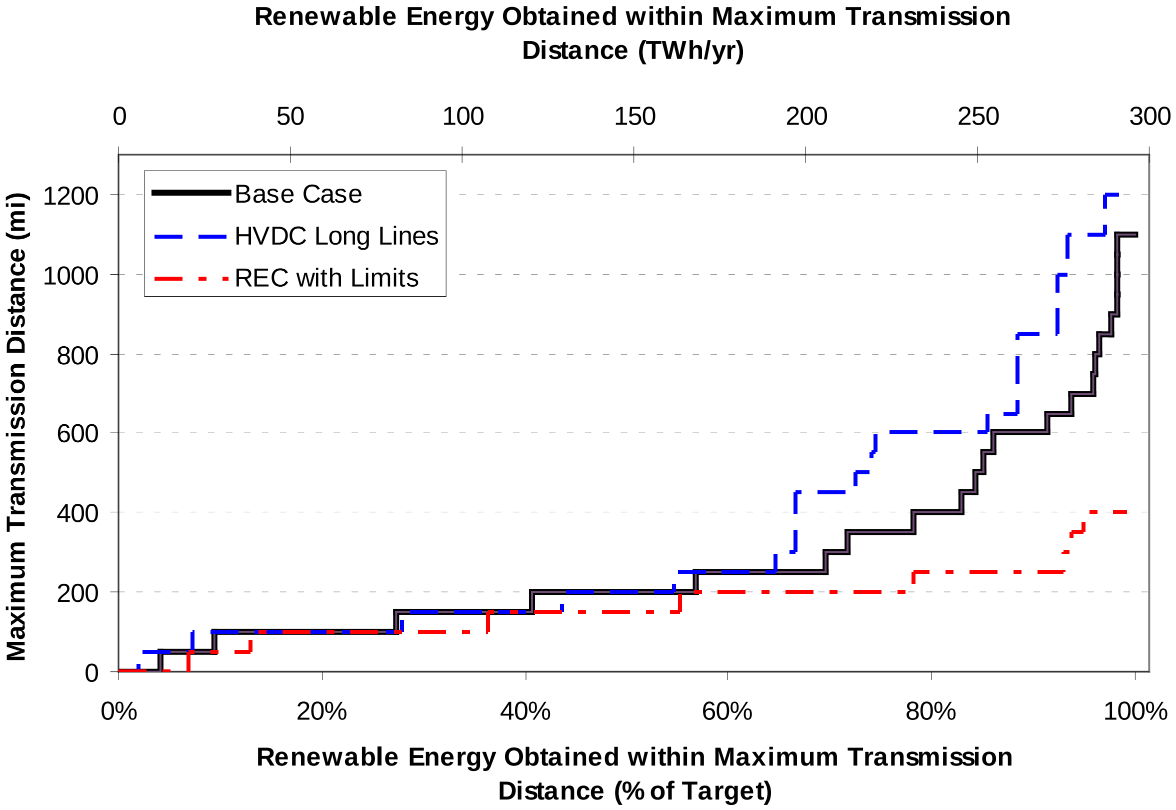


Figure 5. Cost and transmission expansion in 33% renewable energy scenarios

Though there are a number of resources located far from the load zone that procures the resource, only a relatively small portion of the incremental renewable energy added in this case is delivered over new transmission lines longer than 400 miles, which we define as “long lines”. Assuming a WECC-wide competitive allocation of renewable resources, and only considering resources from WREZ hubs, some load zones are found to select resources that are located over 800 miles from the load zone in question. These long lines are found to be significantly more attractive, and prevalent, if they are assumed to be lower-cost 500 kV HVDC lines rather than the single circuit 500 kV AC lines assumed in the Base case: as much as 33% of the incremental renewable energy demand was procured over lines longer than 400 miles when HVDC lines were allowed. Figure 6 shows, on the horizontal axis, the cumulative amount of renewable energy that is procured for different renewable energy targets over transmission lines that are shorter than the maximum transmission length on the vertical axis.

Despite the value of certain long-distance transmission lines, however, it also deserves note that the average transmission distance was much lower, at 230-315 miles across all non-RECs cases, suggesting that any long distance lines built to access renewable energy in the west would ideally be coupled with an even-greater emphasis on shorter-distance lines if cost minimization is a key objective.



Note: Each step increases the maximum transmission distance by 50 miles.

Figure 6. Quantity of RE procured within a maximum transmission distance from each load zone in the Base case, the HVDC Long Lines case, and the REC with Limits case

3.3.1 Renewable Energy Credits

The assumption that each load zone in the WECC region is responsible for procuring renewable energy that is delivered to the load zone to meet its RE target is conservative. One drawback to this approach is that the costs of meeting renewable energy targets are heterogeneous—regions near low-cost, high-quality renewable resources are able to meet their RE targets at much lower cost than regions located at a distance from the same resources. The lowest costs are generally found in the Northern Rocky Mountain region, while the highest costs are in the Northern Pacific region. Costs in the Southwestern states are moderate due to the availability of nearby high-quality solar resources and some limited quantity but high-quality wind and geothermal resources.

An alternative is to allow a decoupling of the responsibility to ensure that new renewable projects are built and the delivery of actual power; trade in Renewable Energy Credits (RECs) is one way to achieve this result. Most states in the WECC already allow the use of RECs, though sometimes with restrictions. We explore the impact of RECs by relaxing the requirement that each load zone physically deliver new renewable energy to its location. Specifically, we require the same total amount of renewable energy to be procured on a WECC-wide basis, but we do not force individual load zones to meet equivalent 33% RE targets; we refer to this case as the WECC REC case. After observing that a number of load zones would (unreasonably) procure nearly 100% of their energy from one RE technology in this unlimited WECC

REC case (selling the RECs in excess of 33% to other load zones), we added constraints such that each load zone could only meet up to 33% of its annual energy needs with any one type of renewable technology and could procure no more than 50% RE in aggregate; we refer to this case as the REC with Limits case. These admittedly arbitrary constraints are meant to reflect the fact that managing very large quantities of any renewable technology is expected to be difficult at penetration levels reaching 33% on an energy basis and that even with a portfolio of different types of renewable resources it is potentially very challenging to mange penetrations in excess of 50%. The REC with Limits case is likely a better reflection of the true benefits of allowing REC trade on a WECC-wide basis. Because the market value adjustment factors do not change with RE penetration, however, these cases subject the WREZ model to conditions that it was not explicitly designed to evaluate; the results should therefore be considered illustrative, and should be evaluated in greater detail using more sophisticated modeling tools.

The overall estimated composition of renewable energy procured in the WECC region does not materially change with the introduction of RECs (Figure 4). The primary change with RECs, however, is the shift in renewable procurement for individual load zones. Load zones with very low adjusted delivered costs for procuring additional renewable energy beyond the amount required to meet their individual RE targets increase procurement of renewable energy when RECs are introduced. Load zones with high costs decrease their procurement of delivered renewable energy and purchase RECs instead.

We illustrate this shift in renewable procurement between the Base case and a case in which RECs are allowed to be traded throughout the WECC region in Figure 7. The figure demonstrates that regions that increase renewable procurement in the REC with Limits case relative to the Base case (upper half of y-axis) are load zones where the marginal adjusted delivered cost of RE in the Base case is much less than the WECC-wide marginal adjusted delivered cost in the REC with Limits case (left half of x-axis). Each bubble in Figure 7 represents a load zone, while the size of the bubble indicates the amount of RE procured by the load zone in the Base case. The further up the y-axis the bubble is, the more the load zone increases its procurement of renewables in the REC with Limits case relative to the Base case. The further to the left the bubble is, the less expensive the marginal resource is to the load zone in the Base case (Base MADC) relative to the marginal resource WECC-wide in the REC with Limits case (REC MADC). The adjusted delivered cost of the marginal RE resource is $66/MWh in the REC with Limits case. The wide spacing of bubbles on the horizontal axis illustrates the heterogeneity of the marginal costs of meeting the 33% RE target in the Base case: the marginal renewable resource for the San Francisco Bay Area, for example, is nearly $50/MWh more costly than the marginal resource for Calgary. This same heterogeneity does not exist in the REC with Limits case, where financial responsibility for meeting WECC-wide targets is more evenly spread across load zones.

Los Angeles increases its procurement of renewables in the REC with Limits case relative to the Base case by taking advantage of the diversity of nearby solar, geothermal, and wind energy resources to become a net seller of RECs. Seattle and San Francisco, on the other hand, have marginal adjusted delivered costs in the Base case that exceed the WECC-wide marginal adjusted delivered cost in the REC cases. Renewable energy delivered to these load zones is relatively expensive. As a result, these load zones are found to satisfy their entire renewable energy targets with RECs, when allowed to do so and when only WREZ resources are considered. Vancouver, Sacramento, and Salt Lake City similarly procure only a fraction of their 33% obligation for renewables through delivered energy, purchasing the rest through RECs. Intuitively, these results make sense when one observes the physical distance between these load zones and the large WREZ-identified renewable resource hubs.

The transmission expansion needs with RECs are substantially lower than in the Base case. As a result, the cost of meeting a WECC-wide 33% RE target with RECs is found to be $5.9/MWh if the technology limits are applied in the REC with Limits case. The primary source of cost savings when using RECs is from a reduction in transmission infrastructure needs and line losses. The total transmission capital investment drops by $8.4 billion in the REC with Limits case, relative to the Base case. Moreover, only 2% of the renewable energy in the REC with Limits case is from renewable resources that are delivered over 400 miles to load zones and 75% is delivered over lines shorter than 200 miles (Figure 6).

These results indicate that wide-spread allowance of REC trading within the WECC may substantially reduce the need for new long-distance transmission, thereby slightly reducing the cost of meeting aggressive renewable energy targets. This conclusion, however, rests to some degree on an assumption that load zones that are near high-quality sources of renewable energy are able to integrate that energy into their own systems without dramatically impacting the market value adjustment factors. More detailed studies should explore this assumption further.

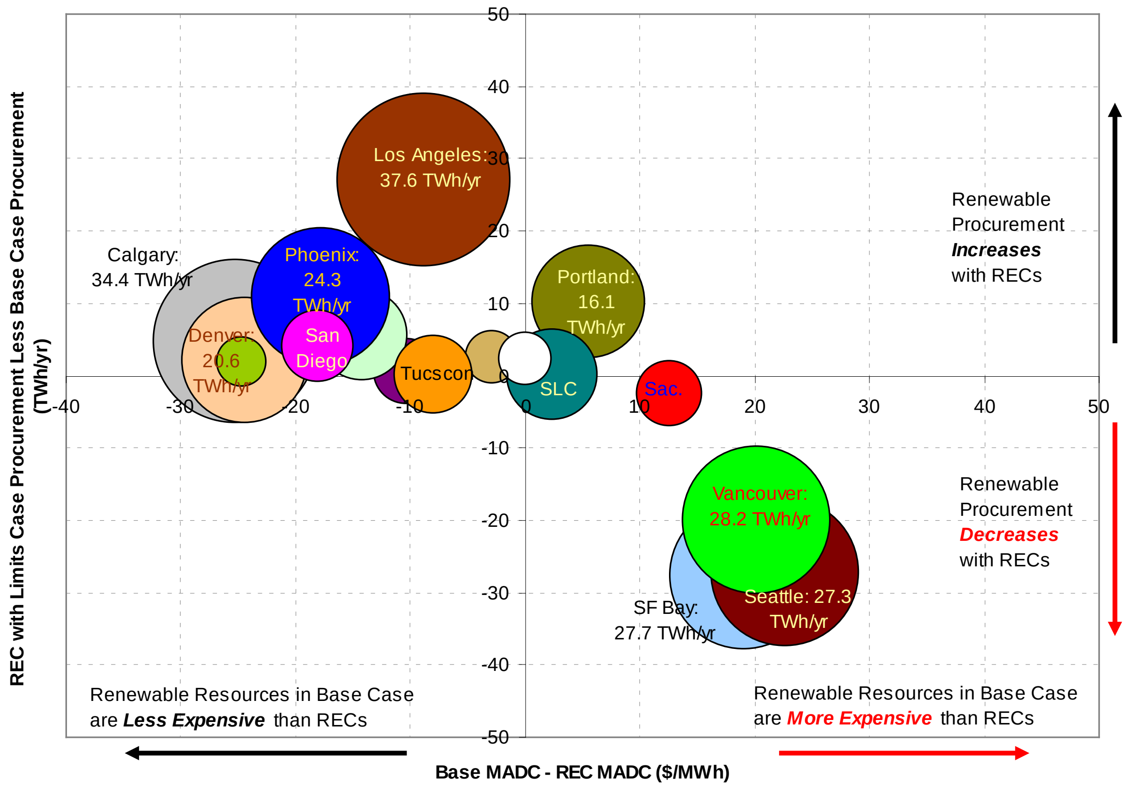


Figure 7. Change in resource procurement between the Base case and REC with Limits case

4. Conclusions

The value of a screening tool like the WREZ model is that it allows fast, simple evaluations of several “what-if” scenarios to understand the importance of different sources of uncertainty and the impact of policy decisions on renewable energy resource selection, transmission expansion needs, and overall costs. It is important to reiterate that our analysis considered only WREZ resources and that non-WREZ resources should be compared to the marginal adjusted delivered costs in different load zones to determine the degree to which non-WREZ resources might be better suited to meeting RE targets. Our analysis also only considered the relative economic attractiveness of renewable resources and did not include the many other factors that are often considered in resource and transmission planning. These results are therefore useful for guiding additional detailed studies but should not be used to justify or reject specific resource procurement or transmission expansion decisions.

Given these caveats, we come to the following conclusions. We found that increasing renewable energy demands increase costs, as less economically attractive resources are required to meet higher targets. Increasing the renewable target from 12% WECC-wide to 33% is found to increase average costs by $20/MWh if all resources are obtained from WREZ hubs. Wind was found to be the largest contributor to meeting WECC-wide renewable energy demands when only resources from the WREZ resource hubs are considered. Wind energy meets 38-65% of the predicted incremental WECC renewables portfolio in the 33% renewable energy cases. One of the most important insights from this screening level analysis was that key uncertainties can shift the balance between wind and solar in the renewable resource portfolio. The factors that affect the balance between wind and solar in resource portfolios should be explicitly considered in alternative transmission planning scenarios. Across all sensitivities to the WECC-wide 33% RE case hydropower, biomass, and geothermal contributions, on the other hand, were found to not change significantly with increasing renewable demand or changes to key assumptions. These resources were largely constrained not on economic terms, but instead based on availability in WREZ resource hubs.

The transmission investment costs to meet a 33% renewable energy target are substantial, but transmission costs are only a fraction of the total delivered costs. Scenarios in which each load zone in the WECC region provides 33% of its energy from new renewable resources in WREZ hubs are found to lead to $22-34 billion in estimated new transmission capacity investment. Transmission and line losses make up only 14-19% of the total delivered cost of renewable energy in these scenarios, however, with the bus-bar cost of the resources being the more influential cost driver. Moreover, if renewable resources not included in the WREZ hubs were considered in this analysis, or if existing transmission was available to offset some of the new transmission demands, total transmission costs would be reduced.

These transmission expansion needs and overall WECC-wide costs can be reduced through the use of Renewable Energy Credits. Assuming that the technical limits placed on renewable procurement for each load zone are reasonable, transmission expansion needs are found to decline by as much as $8 billion when unbundled RECs are allowed on a WECC-wide basis. The total reduction in average renewable energy costs WECC-wide by using RECs is found to be roughly $6/MWh. Transmission costs with RECs decrease to only 10% of the average delivered cost of renewable energy. The ability of load zones to rely upon RECs is a policy decision that should be explicitly considered in more detailed transmission planning studies for renewable energy.

Acknowledgements

The work described in this paper was funded by the U.S. Department of Energy (Office of Electricity Delivery and Energy Reliability, Permitting, Siting and Analysis Division) under Contract No. DE-AC02-05CH11231. We would particularly like to thank Larry Mansueti (U.S. Department of Energy) for his support of this work. We also thank Tim Mason, Kevin Joyce, Josh Finn, Derek Djeu, Jagmeet Khangura, and Sally Maki (Black and Veatch) for the development of the WREZ models and for converting our results into maps; and Doug Larson and Tom Carr (WIEB), Jerry Vaninetti (NextEra Resources), Paul Smith (APS), Andy Leoni (Tri-State G&T), and Bill Pascoe (Pascoe Energy Consulting) for their leadership in the stakeholder process used to develop the WREZ models and transmission input assumptions. We appreciate the detailed technical editing of draft versions of this paper from Mark Wilson (Berkeley Lab). Finally, for reviewing earlier versions of this paper, we thank Doug Larson, Jerry Vaninetti, Paul Smith, Sally Maki, Michael Goggin (AWEA), Tom Darin (DOE), Tom Miller (PG&E), David Hurlbut (NREL), Lynn Coles (NREL), and Jeff Hein (NREL). Of course, any remaining omissions or inaccuracies are our own.

References

Black & Veatch. 2009. *Renewable Energy Transmission Initiative: Phase 1B, Final Report*. Sacramento, California: California Energy Commission. www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF.

Blair, N., W. Short, and M. Mehos. 2008. *Modeling the Impact of State and Federal Incentives on Concentrating Solar Power Market Penetration*. Las Vegas, Nevada, March 4. www.nrel.gov/docs/fy08osti/42851.pdf.

Bonneville Power Administration (BPA). 2009. *2010 BPA Rate Case Wholesale Power Rate Initial Proposal: Generation Inputs Study and Study Documentation*. Portland, Oregon: Bonneville Power Administration. www.bpa.gov/corporate/ratecase/2008/2010_BPA_Rate_Case/docs/WP-10-E-BPA-08.pdf.

Borenstein, S. 2005. *Valuing the Time-Varying Electricity Production of Solar Photovoltaic Cells*. Working Paper. Berkeley, California: Center for the Study of Energy Markets, University of California Energy Institute. www.ucei.berkeley.edu/PDF/csemwp142.pdf.

Borenstein, S. 2008. *The Market Value and Cost of Solar Photovoltaic Electricity Production*. Berkeley, California: University of California Energy Institute. www.ucei.berkeley.edu/PDF/csemwp176.pdf.

Clean and Diversified Energy Advisory Committee (CDEAC). 2006. *Transmission Task Force Report*. Denver, Colorado: Western Governors Association. www.westgov.org/wga/initiatives/cdeac/TransmissionReport-final.pdf.

DeCarolis, J., and D. Keith. 2006. "The economics of large-scale wind power in a carbon constrained world." *Energy Policy* 34(4) March: 395–410.

Denholm, P., R. Margolis, and J. Milford. 2009. Quantifying Avoided Fuel Use and Emissions from Solar Photovoltaic Generation in the Western United States. *Environmental Science & Technology* 43(1): 226-232.

EnerNex Corp., 2010. *Eastern Wind Integration and Transmission Study*. Golden, Colorado: National Renewable Energy Laboratory. NREL/SR-550-47078. http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf

Fripp, M., and R. Wiser. 2008. "Effects of Temporal Wind Patterns on the Value of Wind-Generated Electricity in California and the Northwest." *IEEE Transactions on Power Systems* 23(2): 477-485.

Gross, R., P. Heptonstall, D. Anderson, T. Green, M. Leach, and J. Skea. 2006. *The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network.* Imperial College London: UK Energy Research Centre (UKERC). www.ukerc.ac.uk/Downloads/PDF/06/0604Intermittency/0604IntermittencyReport.pdf.

Gross, R., P. Heptonstall, M. Leach, D. Anderson, T. Green, and J. Skea. 2007. "Renewables and the grid: understanding intermittency." *Proceedings of the Institution of Civil Engineers* 160(ENI): 31–41.

Grubb, M. J. 1991. "Value of variable sources on power systems." *IEE Proceedings Generation, Transmission and Distribution* 138(2): 149–165.

Hirst, E., and J. Hild. 2004. "The Value of Wind Energy as a Function of Wind Capacity." *The Electricity Journal* 17(6) July: 11–20.

Hoff, T., R. Perez, J. P. Ross, and M. Taylor. 2008. *Photovoltaic Capacity Valuation Methods*. Washington D.C.: Solar Electric Power Association. www.solarelectricpower.org/docs/PV%20CAPACITY%20REPORT.pdf.

Holttinen, H., P. Meibom, A. Orths, F. vanHulle, B. Lange, M. O'Malley, J. Pierik, B. Ummels, J. O. Tande, A. Estanqueiro, M. Matos, E. Gomez, L. Söder, G. Strbac, A, Shakoor, J. Ricardo, J. C. Smith, M. Milligan, and E. Ela. 2009. *Design and operation of power systems with large amounts of wind power*. Final Report, Phase one 2006-2008; International Energy Agency (IEA) WIND Task 25. Espoo: VTT. www.ieawind.org/AnnexXXV.html

Lamont, A. 2008. "Assessing the long-term system value of intermittent electric generation technologies." *Energy Economics* 30(3) May: 1208–1231.

Milligan, M.R. 2000. "Modeling utility-scale wind power plants. Part 2: Capacity credit." *Wind Energy* 3(4): 167–206.

Milligan, M., and K. Porter. 2006. "The Capacity Value of Wind in the United States: Methods and Implementation." *The Electricity Journal* 19(2) March: 91–99.

Mills, A., A. Phadke, and R Wiser. 2010. *Exploration of Resource and Transmission Expansion Decisions in the Western Renewable Energy Zone Initiative.* Berkeley, California: Lawrence Berkeley National Laboratory. LBNL-3077E. http://eetd.lbl.gov/ea/emp/reports/lbnl-3077e.pdf.

Mills, A., and R. Wiser. Forthcoming. *Implications of Wide-Area Geographic Diversity for Short-term Variability of Solar Power.* Berkeley, California: Lawrence Berkeley National Laboratory.

Olson, A., R. Orans, D. Allen, J. Moore, and C.K. Woo. 2009. "Renewable Portfolio Standards, Greenhouse Gas Reduction, and Long-Line Transmission Investments in the WECC." *The Electricity Journal* 22(9): 38–46.

Pletka, R. and Finn, J. 2009. *Western Renewable Energy Zones, Phase 1: QRA Identification Technical Report*, Golden, Colrado: National Renewable Energy Laboratory. NREL/SR-6A2-46877. www.nrel.gov/docs/fy10osti/46877.pdf.

Stoft, S. 2008. "The Surprising Value of Wind Farms as Generating Capacity." *SSRN eLibrary* (August 23). http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1250187.

U.S. Department of Energy (DOE). 2008. *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply*. Golden, Colorado: National Renewable Energy Laboratory. www.20percentwind.org/20percent_wind_energy_report_05-11-08_wk.pdf.

U.S. Department of Energy (DOE). Forthcoming. *Integration of Concentrating Solar Power and Utility-Scale Photovoltaics into Regional Electricity Markets.* Washington D.C.: U.S. Department of Energy.

Wiser, R., and M. Bolinger. 2009. *2008 Wind Technologies Market Report*. Golden, Colorado: U.S. Department of Energy. www1.eere.energy.gov/windandhydro/pdfs/46026.pdf.

[1] The National Renewable Energy Laboratory (NREL) has since combined the functionality of the WinDS and CSDS models into the Regional Energy Deployment System (ReEDS). The NREL ReEDS model is described in detail at: www.nrel.gov/analysis/reeds/.

[2] The GE algorithm was not used to choose between different renewable resource types, however. Instead the algorithm was used to pick resources to meet specific targets for wind or solar expansion.

[3] A *fully subscribed* transmission line is one in which the nameplate capacity of the renewable resources procured over the line is equivalent to the transfer capacity of the transmission line. An *over subscribed* line, where the nameplate capacity of the resource exceeds the transfer capacity of the transmission line, may lead to increased risk of curtailment and was not explicitly evaluated in our analysis. This is a different definition than the *utilization* of a transmission line. Utilization is the ratio of the energy transmitted over a line relative to the energy that would be transmitted if the amount of power flowing over the line were equivalent to its full transfer capacity at all times.

[4] Other possible adjustment factors, such as value in reducing carbon emissions, are useful when comparing renewable and non-renewable resources. Because the WREZ model is focused on determining the relative ranking of different renewable resources, however, we exclude considerations of carbon reduction value.

[5] Assumed levelized fixed costs for peaker plants vary within the western United States: studies in California have used costs as high as $200/kW-yr, while integrated resource plans elsewhere use values as low as $92/kW-yr.

[6] We found that the calculation of the capacity factor during the peak 10% of load hours using detailed 8760 hour time series for both the renewable resource and the load produced qualitatively similar results to the capacity factor during the peak 10% of load hours using the 12 X 24 generation and load profiles.

[7] The scenario with the largest procurement of wind leads to a wind penetration of 21% west-wide on an energy basis. The remaining renewable energy required to reach a WECC-wide 33% RE target is a mix of solar, geothermal, biomass, and hydro. As such, the integration cost range for studies up to 20% wind on an energy basis should provide a reasonable indication of the integration costs expected in even a WECC-wide 33% RE case.