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

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Environmental Energy
Technologies Division

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Abstract

Building transmission to reach renewable energy (RE) 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. In this report 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.

Of the renewable resources in WREZ resource hubs, and under the assumptions described in this report, 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%). Solar exceeds wind by a small margin only when solar thermal energy is assumed to experience cost reductions relative to all other technologies. Biomass, geothermal, and hydropower are found to represent a smaller portion of the selected resources, largely due to the limited resource quantity of these resources identified within the WREZ-identified hubs (16-23% combined). 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. Uncertainties and policies that impact bus-bar costs are the most important to evaluate carefully, but factors that impact transmission costs and the relative market value of each renewable option can also be important. Under scenarios in which each load zone must meet 33% of its load with delivered renewable energy from the WREZ-identified resource hubs, the total transmission investment required to meet the 33% west-wide RE target is estimated at between \$22 billion and \$34 billion. Although a few of the new transmission lines are very long—over 800 miles—most are relatively short, with average transmission distances ranging from 230-315 miles, depending on the scenario. Needed transmission expenditure are found to decline to \$17 billion if wide use of renewable energy credits is allowed; consideration of renewable resources outside of WREZ-identified hubs would further reduce this transmission cost estimate. Even with total transmission expenditures of \$17-34 billion, however, these costs still represent just 10-19% of the total delivered cost of renewable energy.

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List of Figures and Tables

Acronyms and Abbreviations

ADC	Adjusted delivered cost
AWEA	American Wind Energy Association
B&V	Black & Veatch
CAES	Compressed air energy storage
CCGT	Combined-cycle gas turbine
CDEAC	Clean and Diversified Energy Advisory Committee
CPUC	California Public Utilities Commission
DOE	Department of Energy
E3	Energy and Environmental Economics, Inc.
GAMS	General Algebraic Modeling System
GE	General Electric
GHG	Greenhouse gas
GW	Gigawatt
IPP	Independent power producer
ITC	Investment tax credit
kW	Kilowatt
kV	Kilovolt
MADC	Marginal adjusted delivered cost
MW	Megawatt
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
PTC	Production tax credit
RE	Renewable energy
REC	Renewable energy credit
ReEDS	Regional Energy Deployment System
RPS	Renewables portfolio standard
TEPPC	Transmission Expansion Planning and Policy Committee
TOD	Time-of-delivery
TWh	Terawatt-hour
WECC	Western Electricity Coordinating Council
WEIL	Western Electric Industry Leaders
WGA	Western Governors Association
WREZ	Western Renewable Energy Zones initiative
ZITA	Zone Identification and Technical Analysis working group

Executive Summary

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 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 amount and location of 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 which, in combination, can help identify the importance of different sources of uncertainty and the impact of policy decision on renewable resource selection, transmission expansion, and overall costs.

In this report, 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 capacity.

Our analysis 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.

Framework for Comparing WREZ Resources

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 twenty load zones identified in the Western Electricity Coordinating

Council (WECC). In addition, a user can assess the economic attractiveness of resources from the perspective of any other load zone in order to evaluate the potential for collaboration with other load zones in building transmission lines to access those resources.

The relative economic attractiveness of a renewable resource to a load zone is measured by a metric that we call the *adjusted delivered cost* (ADC). The ADC is the delivered cost of a resource to a load zone (considering generation costs and transmission costs), adjusted for key market value adjustment factors, and is presented in dollars per megawatt-hour ($/MWh). Market value adjustment factors are included to enable a screening-level comparison of technologies that have different generation characteristics and therefore different value to the electricity system. Figure ES-1 illustrates the various components of the ADC, along with a representative case that demonstrates how the relative economic attractiveness of various resources can shift as each of the economic drivers included in the ADC is considered.

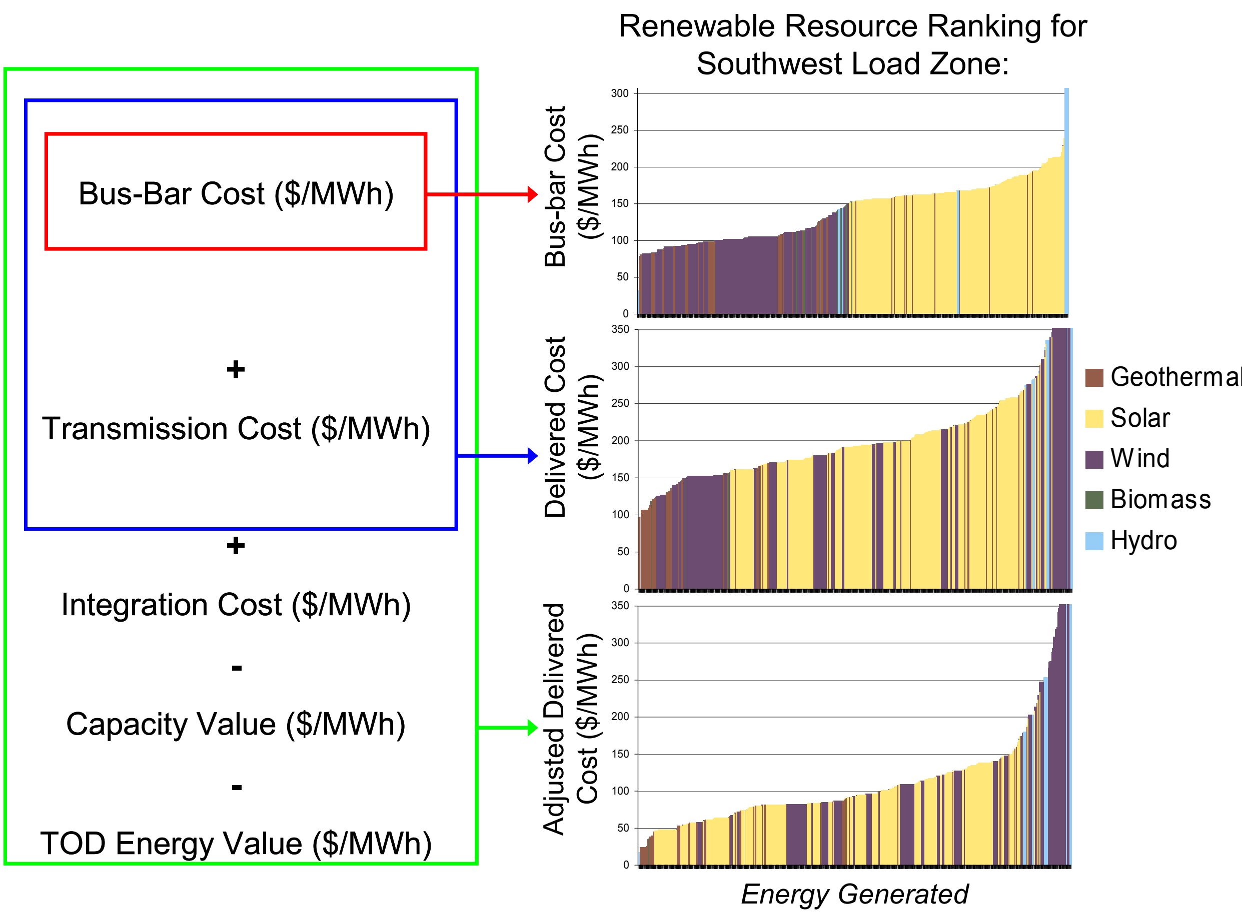


Figure ES-1. Framework for evaluating the economic attractiveness of renewable resources to load zones in the WREZ model

In this report, the WREZ model is used to determine what new WREZ-identified renewable resources might be procured by load zones within the WECC region to meet renewable targets in 2029. The loads are assumed to meet these targets at minimum cost while respecting the limited quantity of resources in high quality resource hubs that are attractive to multiple load zones.

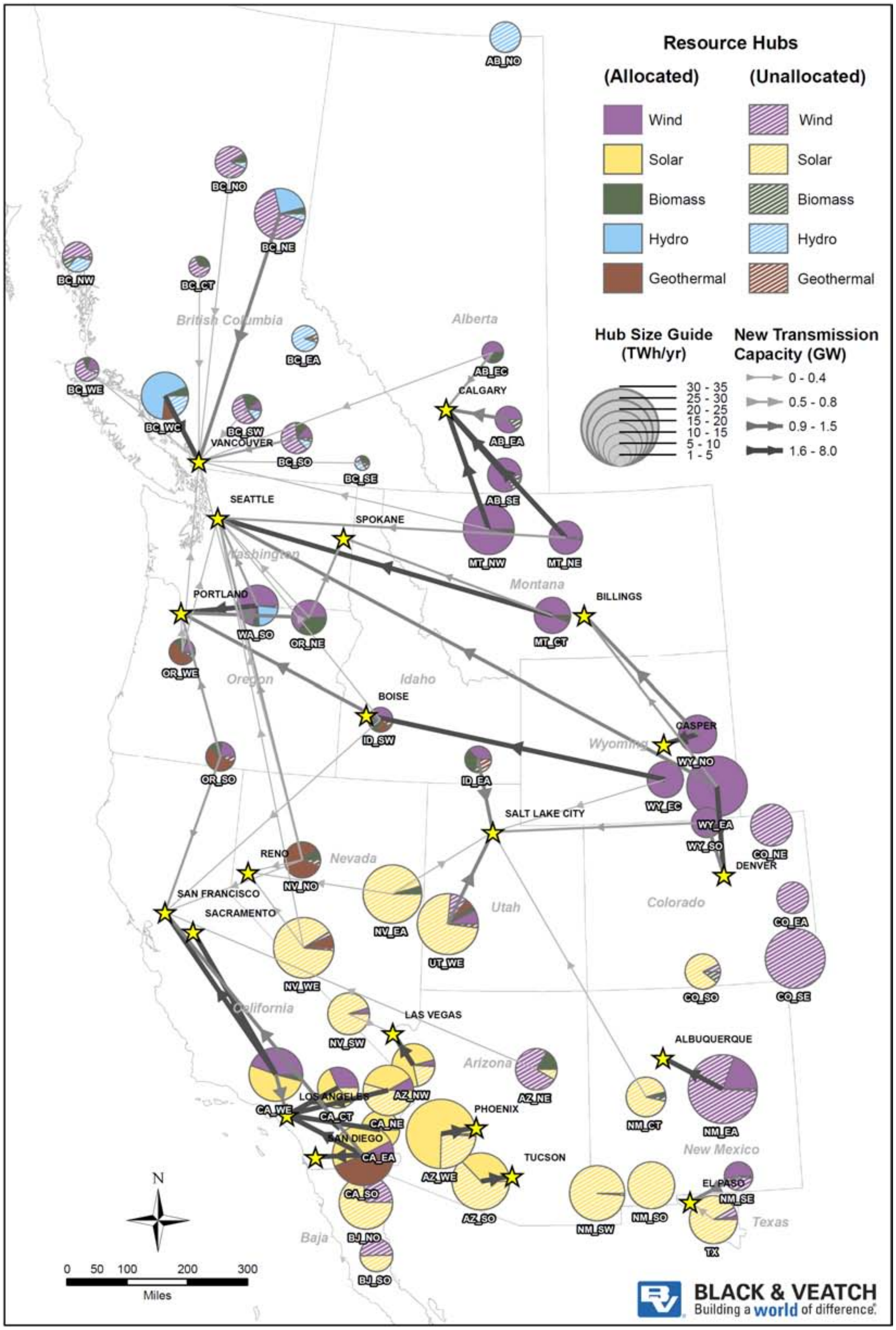
Analysis Results

We begin our analysis by evaluating different targets for new WREZ-identified renewable resources, assuming that each load zone must physically deliver those resources over new transmission to their zone. As shown in Table ES-1, 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 approximately $20/MWh. Regardless of the target level, new transmission costs total roughly 15% of total delivered costs.

Table ES-1. 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%	

We then 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 ES-2. These results illustrate the least-cost procurement of WREZ resources, under the many assumptions detailed in the body of the report. 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.

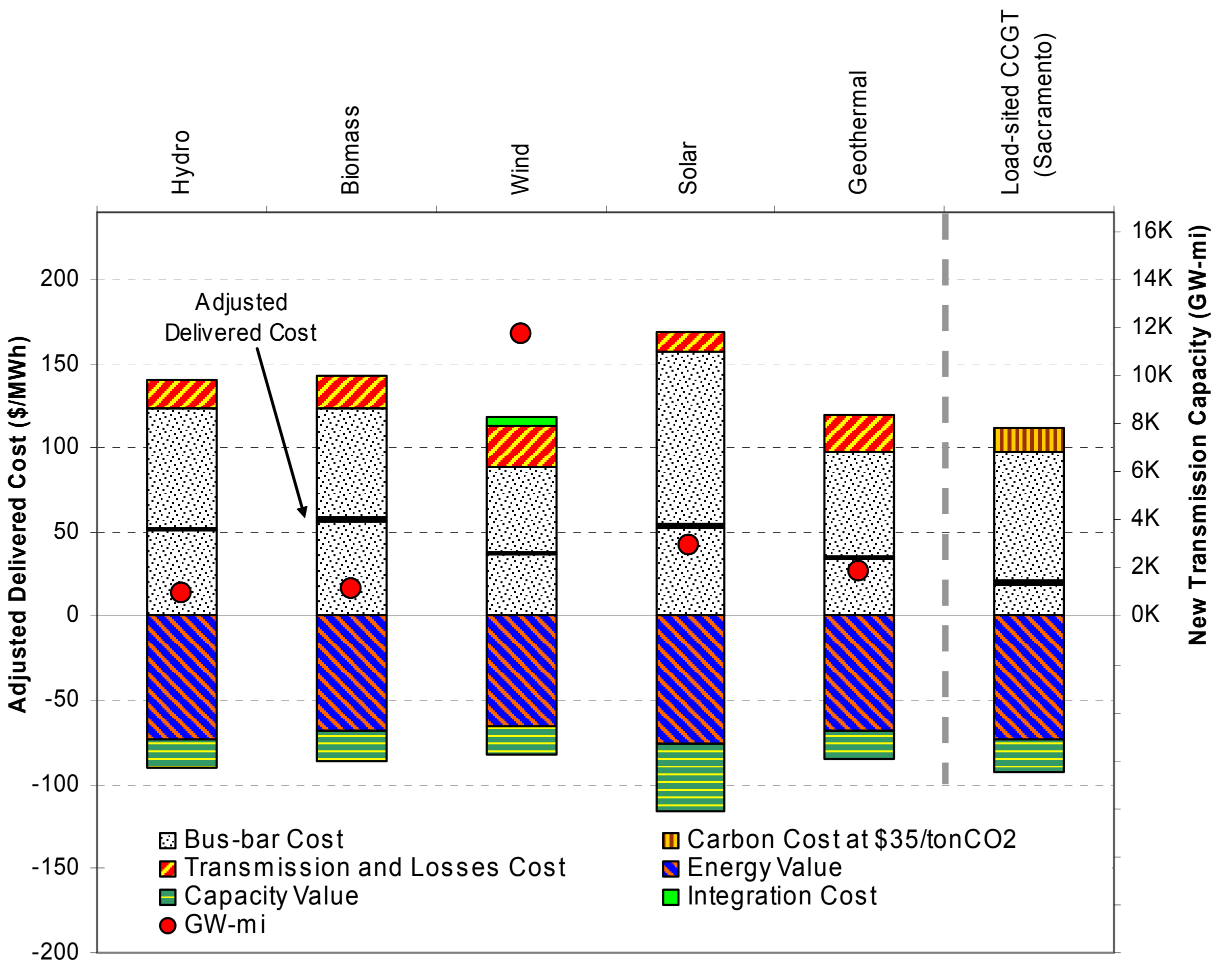


Map created 11/03/2009 by Sally Maki and Josh Finn

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

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

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 ES-4; the scenarios themselves are defined in the body of the report.

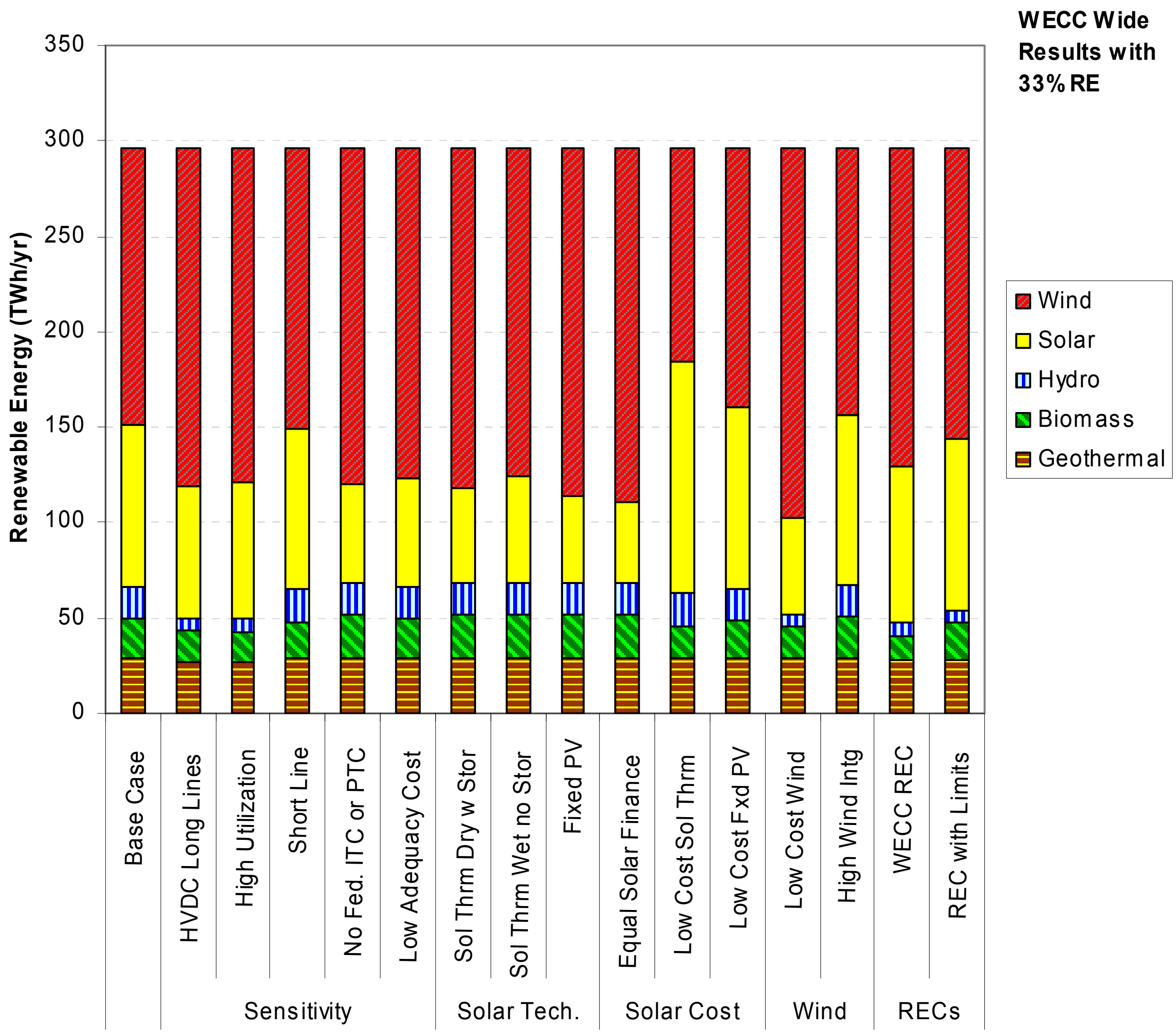


Figure ES-4. Resource composition relative to the Base case for several different 33% RE scenarios

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 is illustrated in Figure ES-5. 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.

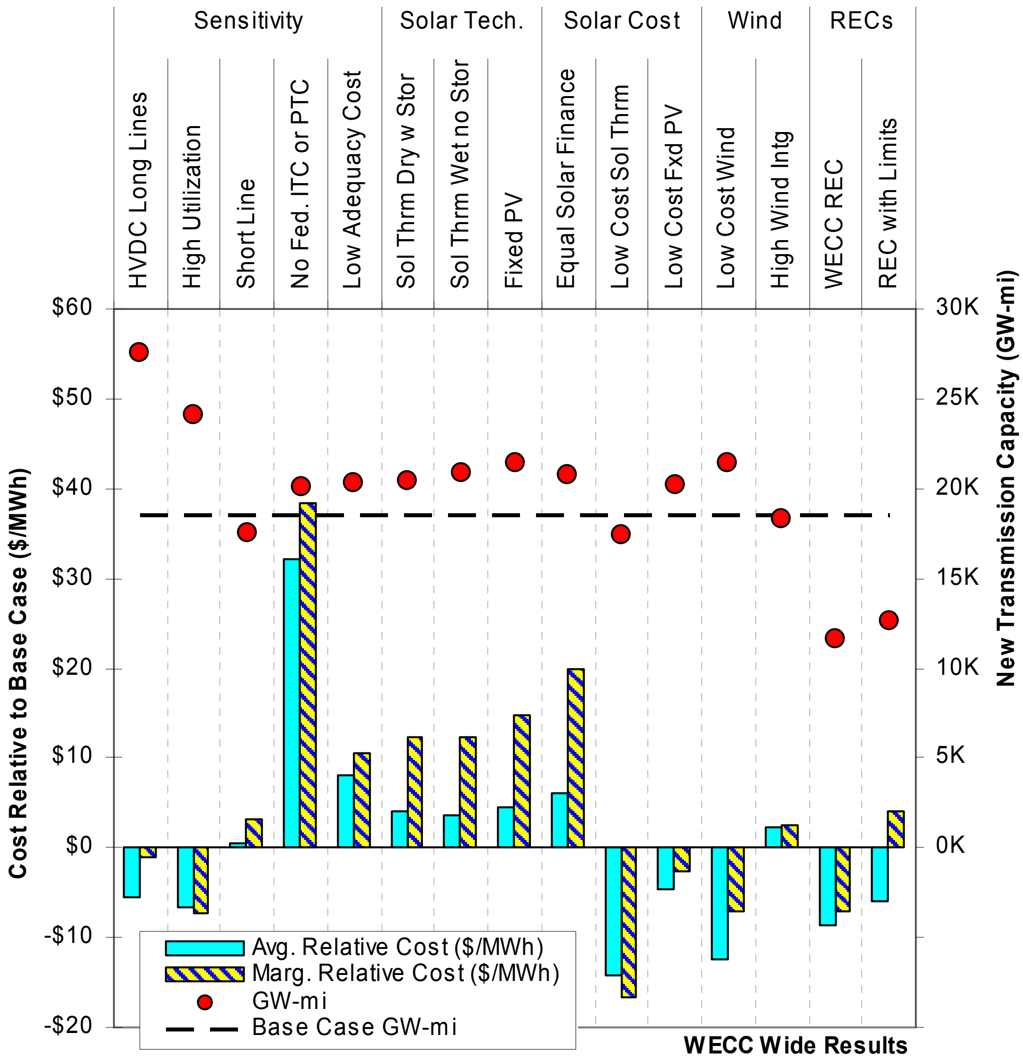
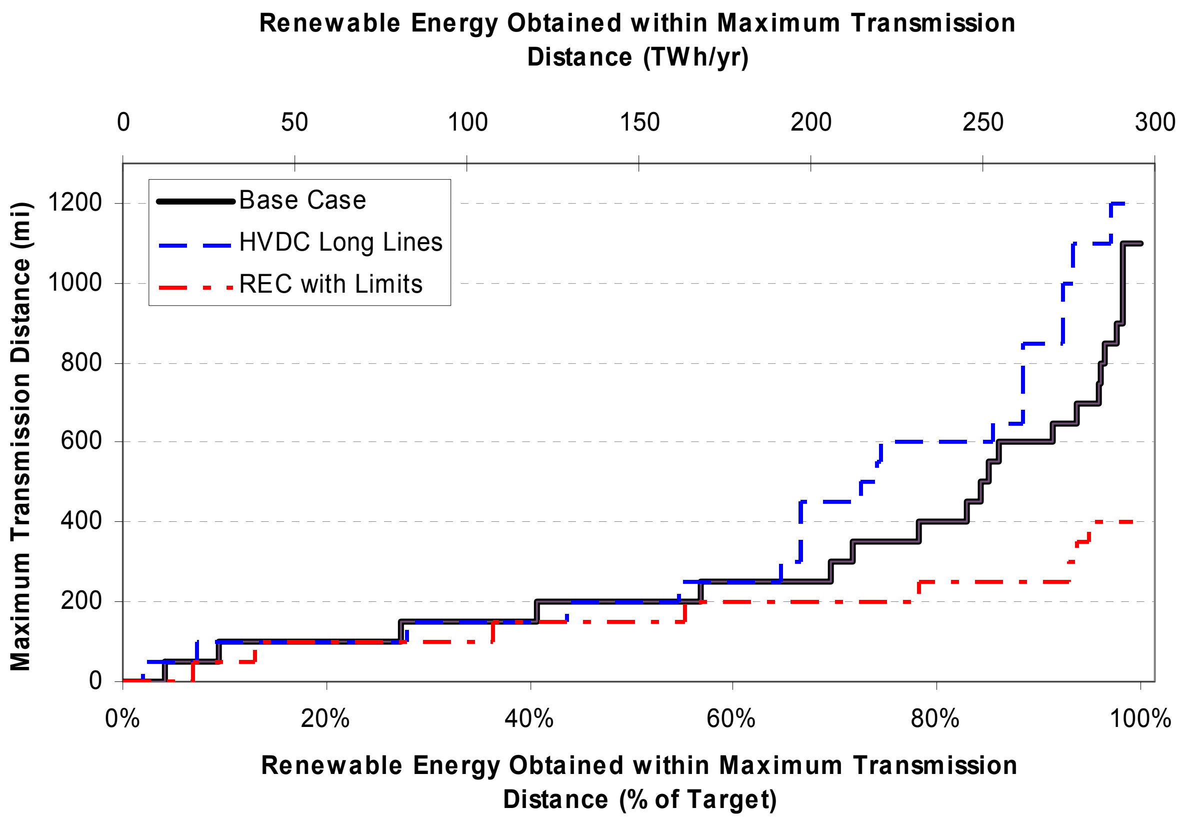


Figure ES-5. Cost and transmission expansion relative to the Base case for several different 33% RE scenarios

We find that the transmission investment costs required to meet a 33% WECC-wide renewable energy target are substantial, but are only a fraction of the total delivered costs. Specifically, the investment in transmission expansion for scenarios in which each load zone in the WECC region provides 33% of its energy from WREZ renewable resources hubs is estimated at $22-34 billion. The primary technology driving transmission expansion on a WECC-wide basis is found to be wind energy. Transmission and line losses, however, make up only 14-19% of the total delivered costs of renewable energy supply; the much-larger contributor to delivered costs is the bus-bar cost of the resources itself. 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.

Our results indicate that long transmission lines can be economically justified in particular cases, but that the majority of transmission lines are found to be relatively short (Figure ES-6). Figure ES-6 shows on the horizontal axis the cumulative amount of renewable energy that is procured over transmission lines that are shorter than the maximum transmission length on the vertical axis. Particular load zones are sometimes found to select renewable resources 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 in the HVDC Long lines case): as much as 33% of the incremental renewable energy demand was procured over lines longer than 400 miles when HVDC lines were allowed. 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, suggesting that any long distance lines built to access renewable energy in the west would ideally be coupled with an even-greater emphasis on short-distance lines.



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

Figure ES-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.

Under the cases described so far, we have assumed that each load zone must take physical delivery of the renewable energy from WREZ hubs via new transmission. The resulting costs of meeting the 33% renewable energy target across load zones in these cases are heterogeneous.

Resources of differing capital cost, quality, location, and market value are procured by different load zones to meet their individual renewable energy targets, leading to differing costs of renewable energy across load zones. 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.

The figures included earlier, however, also present results for two cases in which unbundled renewable energy credits (RECs) are allowed. By relaxing the requirement that each load zone must physically deliver sufficient renewable energy to their zone to meet the 33% renewable energy target, we found that transmission expansion needs could be reduced by as much as $8 billion; of all of the scenarios that we modeled, allowing RECs had the largest impact on reducing necessary transmission expenditures. Allowing the free trade of RECs can reduce transmission expansion by allowing (1) load zones near high-quality resource areas to increase procurement of renewables, and (2) load zones far from high-quality resources to purchase credits rather than building transmission to deliver resources to their load. As a result of the impact on transmission expenditure, free trade in RECs is found to reduce the average renewable energy costs WECC-wide by roughly $6/MWh. The ability of load zones to rely on RECs is a policy decision that should be explicitly considered in more detailed transmission planning studies for renewable energy.

1. Introduction

New transmission requires 7-10 years or even longer to plan, permit, and construct; once built, its economic life can span multiple decades. Planning for transmission expansion therefore requires consideration of several uncertainties about the future state of the world including the sources, costs, and locations of electricity generation options, expected load growth, and policies that require or incentivize the procurement of certain forms of electricity generation. Transmission expansion for renewable energy is further complicated by the location-dependent quality of renewable resources, the mismatch between the time required to permit and build transmission and the shorter time required to permit and build renewable generation, the low capacity factors of some renewable energy projects that result in low utilization of transmission capacity, and the relatively small size of individual renewable energy projects compared to the size of the total renewable resource of similar quality in a surrounding area (Mills et al., 2009).

To overcome some of these transmission planning challenges, the U.S. Department of Energy (DOE) and the Western Governors' Association created the Western Renewable Energy Zone initiative (WREZ) to identify high-quality, large renewable resource regions in the West and to develop conceptual transmission expansion plans for renewable resources in the Western Interconnect.[1] One of the key deliverables of the WREZ project is a set of publicly available renewable generation and transmission screening tools, collectively called the "WREZ model," based on the WREZ renewable resource database. The model allows users to compare, at a screening level, the economic attractiveness of all renewable resources included in the database, and to identify potential partners for jointly developed transmission to mutually attractive resource areas. The WREZ model was developed by a diverse group of Western resource and transmission planning experts in collaboration with Black & Veatch and Lawrence Berkeley National Laboratory. The model is seeded with a database of information on renewable resource locations, quantities, and estimated costs that was developed through a stakeholder-driven process. That process, managed in part by the National Renewable Energy Laboratory, included state utilities commissions and wildlife agencies, Canadian provincial premiers, renewable energy developers, utility planners, environmental organizations, and several federal agencies.

The renewable resource database in the WREZ model is based on discrete geographic regions, called WREZ hubs, that might justify the construction of regional transmission. Specifically, the WREZ effort focused on identifying high-quality renewable energy resources in environmentally preferred locations that might justify the investment in a 500 kV transmission line delivering 1,500 MW of new capacity. The database is therefore not a comprehensive catalog of all renewable resources in the Western Interconnection. WREZ stakeholders recognized that renewable resources located outside of WREZ resource hubs would receive development attention, particularly in cases where those resources could access existing transmission capacity, or where the resource areas were proximate to load (WGA, 2009). To keep the analysis tractable and to focus attention on transmission investment decisions, however, these non-WREZ resources were not characterized to the same level of detail as were those resources located within WREZ hubs (the WREZ model does allow users to custom define characteristics of non-WREZ resources to compare to WREZ resources). As a result, in the analysis presented in this report, we evaluate scenarios in which western loads meet renewable targets only with WREZ-

[1] The WREZ Initiative is described in more detail and the WREZ models are available at www.westgov.org.

identified resources located in WREZ hubs. The results of this assessment are informative, but because they exclude non-WREZ resources, the results 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. Such analysis should, however, recognize that non-WREZ resources may not be of sufficient size to justify new large transmission and may therefore require lower voltage, and higher per-unit cost transmission.

The WREZ model is designed to be used as a screening tool to identify attractive renewable resources and the transmission expansion that may be required to access those resources under a wide variety of scenarios and assumptions. As a screening tool, the WREZ model enables users to rapidly identify key uncertainties or assumptions that broadly determine the choice of resources or transmission expansion solutions within the footprint of the Western Electricity Coordinating Council (WECC). For this paper, we use the WREZ data and model to identify resource choices and transmission expansion needs under several uncertainties and scenarios. These resource and transmission decisions are evaluated based on the relative economic attractiveness of various renewable resources to load zones to meet specific renewable targets, considering generation (or bus-bar) costs, transmission costs, and various market value adjustments that capture the relative value renewable resources in offsetting fossil generation.

To be clear, as a screening-level assessment, this analysis is not a comprehensive evaluation of all of the factors that must be considered during more-detailed evaluations of specific renewable projects and transmission investments; for example, our assessment does not include considerations of system reliability, operational feasibility, and environmental impact. As a result, specific resource procurement decisions and transmission investments cannot be justified and should not be rejected because of the analysis presented in this paper. The results of this screening-level analysis can, however, help resource and transmission planners identify the key uncertainties and scenarios that should be explicitly evaluated in more detailed and data-intensive planning tools. Results from this analysis, for instance, can be used to help identify attractive resources for consideration in advanced transmission planning tools at the many sub-regional transmission planning groups in the West and the Transmission Expansion Planning and Policy Committee (TEPPC) at the WECC. In addition, the WREZ model is useful for policy makers. The model can help answer questions about the potential effects of federal tax incentives on the selection of renewable resources as well as the required transmission necessary to access those resources. Similarly, the WREZ model can be used to provide insight into the impact of policy decisions such as changing renewable energy (RE) procurement targets or allowing loads to use Renewable Energy Credits (RECs) to satisfy those RE requirements.

Given the broad audience for the WREZ model, it was designed with a focus on transparency and simplicity. The model is implemented in an Excel-based spreadsheet so that users can see the inputs and calculations that are used to evaluate resources and transmission under any set of user-defined assumptions. This simple and transparent approach has been used effectively in settings that involve a broad set of stakeholders.[2] The WREZ model allows resource planners to

[2] One particular example of such an approach is the Energy and Environmental Economics, Inc. (E3) Greenhouse Gas (GHG) Calculator used by the California Public Utilities Commission (CPUC) to evaluate policies (including renewable development and energy efficiency) to reduce the greenhouse gas emissions in the electricity and natural

identify attractive resources from their perspective, similar to the renewable resource ranking developed in the California Renewable Energy Transmission Initiative (RETI) with Black & Veatch (B&V, 2009). The WREZ model, however, goes further by allowing any load zone in the entire Western Interconnection to use the model to evaluate the relative attractiveness of renewable resources located within WREZ-identified hubs, and to identify potential partners (or competitors) in building transmission to access those resources. A key component of the WREZ model is the estimation of the bus-bar costs, transmission costs, and market value of different resources to different load centers in one screening tool.

In contrast to simple Excel-based screening tools, transmission and resource planners often use proprietary, advanced simulation software that is data intensive and is developed to answer specific questions. For example, the WECC transmission path rating process relies on power flow, stability, and post-transient studies to identify the simultaneous power transfer across transmission paths due to new transmission investments. These studies focus on particular snapshots during times of stressful operating conditions. Planners are required to input both the output of all generators and the demand for power at all loads during the study test cases. The WECC TEPPC transmission planning forum, on the other hand, uses an advanced production cost model (PROMOD) to simulate the dispatch of all generators in the WECC region while considering transmission limitations and generation characteristics. The model includes detailed hourly renewable generation profiles and part-load efficiencies and start-up times of conventional generators. A production cost model of this nature can show the impact of adding renewable resources or transmission to the WECC grid, but it requires the user to input the location and type of renewable generation to include in the model. The production cost model does not provide direct guidance in selecting which renewable resources to include in the model. Finally, within the resource planning process, utilities and others often use models that help choose between several different supply-side (and sometimes demand-side) energy options in meeting future load. These models, however, rarely include detailed information about transmission costs and different generation profiles. Results from the WREZ model will not replace these other tools and methodologies, but can provide useful guidance in directing and providing input into those more-detailed assessments.

This paper is 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. In so doing, it builds upon a wide range of earlier studies that have evaluated transmission planning in the West 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).[3] The Wind Deployment System

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gas sectors in California. The E3/CPUC GHG Calculator is publicly available at www.ethree.com/cpuc_ghg_model.html

[3] CDEAC evaluated a reference case and three scenarios: high efficiency, high renewables, and high coal. The reference case added 20 gigawatts (GW) of incremental renewables while the high renewables case added 62 GW of renewables. Increasing the renewables above the reference case added $6.8 billion in new transmission. 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.

(WinDS)[4] 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[5] for the *Western Wind and Solar Integration Study* (Lew et al., 2009). 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.[6]

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 Interconnect. In Section 3 we vary several of the key parameters and uncertainties, one at a time, for representative wind, solar, and geothermal projects to show the degree to which different parameters can affect the economic attractiveness of the different renewable resources. In Section 4 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 Interconnect. 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

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[4] The National Renewable Energy Laboratory (NREL) has since combined the functionality of the WinDS and CSDS models into the Regional Energy Deployment System (ReEDS). ReEDS is another advanced generation and transmission expansion model that can be used to make regional renewable energy choices to meet specific targets. ReEDS includes a significant database of renewable resource quantity, quality, and cost information, along with the U.S. transmission network. The model is used to evaluate policy impacts on conventional and renewable generation and transmission expansion out to 2050 in two-year time steps. The transmission expansion analysis in ReEDS is based on a simplified transport model rather than a powerflow model that captures the physics of electricity flow in transmission networks. The ReEDS model is very powerful and more detailed than the WREZ model, however, it is implemented in the General Algebraic Modeling System (GAMS) language and is not available in a simple Excel-spreadsheet form. Sensitivity cases and scenarios, therefore, cannot be evaluated by a wide set of stakeholders. The NREL ReEDS model is described in detail at: www.nrel.gov/analysis/reeds/.

[5] 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. Furthermore, due to intense data requirements for the method employed by GE, the algorithm was not implemented in a publicly available Excel spreadsheet. The GE site selection algorithm methodology and preliminary results are available at: http://wind.nrel.gov/public/WWIS/stakeholder%20meetings/8-14-08/GE4-New%20Scenarios.pdf.

[6] Olson et al. (2009) evaluated the cost effectiveness of expansion of different transmission corridors based on the cost effectiveness of wind, solar, geothermal, biomass, and hydro in meeting renewable targets and several fossil-fuel alternatives for multiple load zones in the WECC region. Overall, their analysis is very similar to the analysis presented in this paper, with a number of methodological differences that affect the relative valuation of renewable resources. Additional results from their earlier study, "Load-Resource Balance in the Western Interconnection: Towards 2020" is available at www.weilgroup.org/E3_WEIL_Complete_Study_2008_082508.pdf. The estimated cost of cost-effective long-distance transmission to meet GHG and RPS targets in 2020 is $5 to $11 billion.

offered in Section 5, while additional details regarding assumptions, methods, and results are provided in the appendices.

2. Overview of WREZ Model: Framework for Comparing WREZ Resources

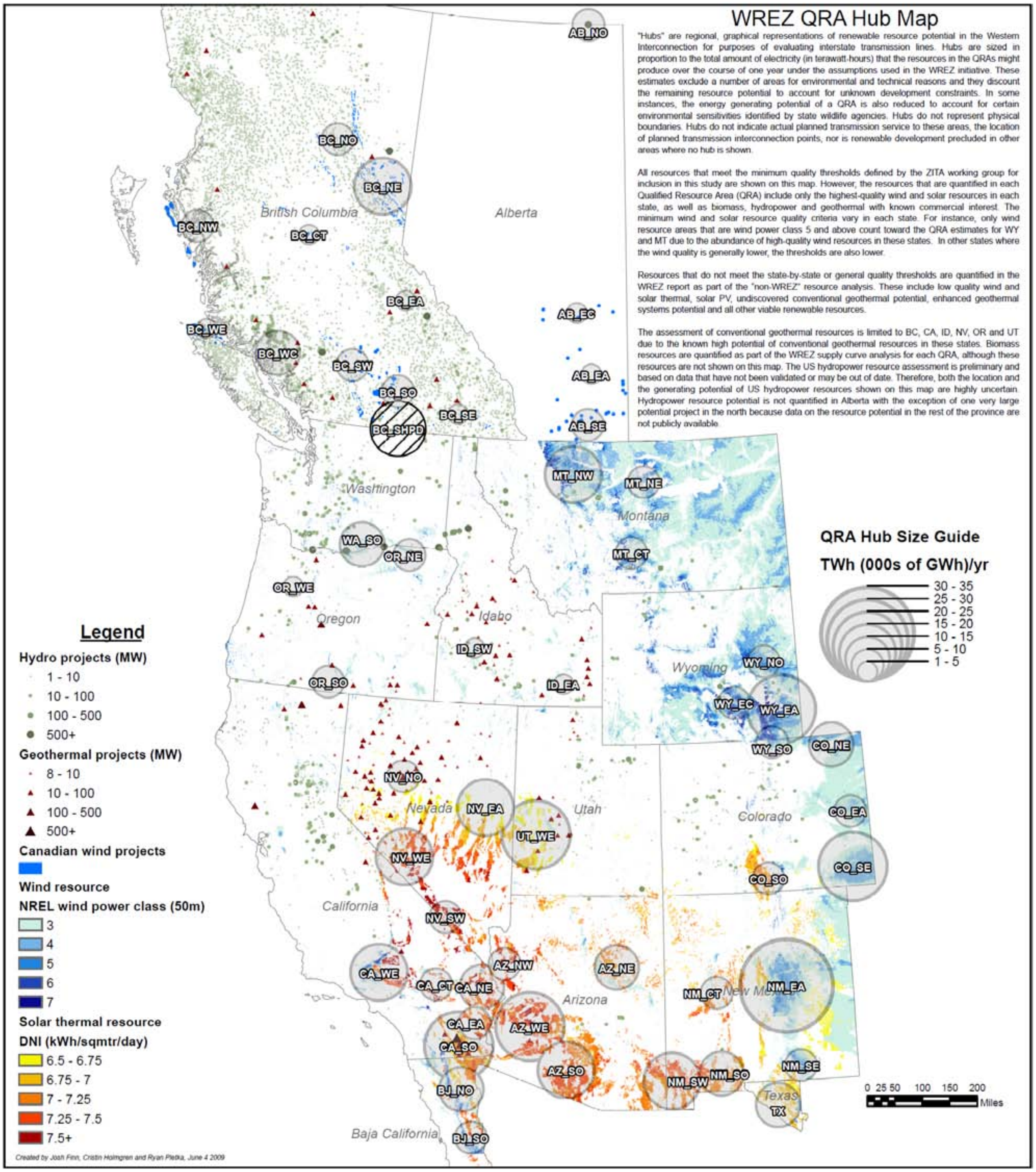
2.1 Overall Framework

The WREZ model separates the Western Interconnection into twenty load zones geographically located near major metropolitan regions and fifty-five renewable resource hubs. At least one load zone was identified in each state and province; states with large populations often have multiple load zones. Renewable resource hubs represent geographic areas with at least 1,500 MW of high-quality potential renewable energy projects located within a 100 mile radius (WGA, 2009). Details on the data and resource selection process used to identity and characterize these resource hubs are available from Pletka and Finn (2009). The potential renewable resources identified in the WREZ hubs are summarized by resource type and state in Table 1 and shown graphically in Figure 1.

Table 1. Renewable resource potential of resources identified in the WREZ model[7]

State or Province		Renewable Resource Identifed in WREZ Model (TWh/yr)				
		Geothermal	Biomass	Hydro	Wind	Solar
AB	Alberta	-	1.6	6.3	13.6	-
AZ	Arizona	-	1.9	-	9.2	66.9
BC	British Columbia	1.4	6.5	21.4	34.1	-
BJ	Baja, Mexico	-	-	-	8.8	17.6
CA	California	10.9	0.6	-	16.0	54.6
CO	Colorado	-	0.8	-	42.7	6.8
ID	Idaho	0.6	2.3	-	4.0	-
MT	Montana	-	1.0	-	32.4	-
NM	New Mexico	-	0.4	-	36.6	45.1
NV	Nevada	9.0	1.9	-	1.1	54.9
OR	Oregon	5.6	4.5	-	7.4	-
TX	Texas	-	-	-	1.3	14.1
UT	Utah	1.1	0.6	-	4.2	18.6
WA	Washington	-	0.6	2.5	8.2	-
WY	Wyoming	-	-	-	48.9	-
Total		28.6	22.9	30.3	268.5	278.8

[7] Our analysis ignores projects that were identified in the WREZ resource database that were smaller than 50 MW. This excludes only 1.7% of the total renewable resources identified in the WREZ database and allows us to track 30% less resource project IDs in the analysis.



Source: Pletka and Finn (2009) Figure 5-2.

Note: Additional details for WREZ hubs available with original figure.

Figure 1. WREZ hub map

As discussed in the introduction, renewable resources located outside of WREZ hubs were not considered in our analysis, though we recognize that there are non-WREZ renewable resources that are viable for meeting some fraction of the overall renewable resource demand in WECC.

Additional information on the vast quantity of these non-WREZ resources is summarized in Appendix E. Since we do not evaluate non-WREZ hub resources in our analysis, our results 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 renewable energy targets by 2029. Given the focus on resources in WREZ hubs, the results of this analysis should be used to understand the transmission and renewable energy procurement decision of one scenario relative to another; one should not interpret these results as projections of future transmission expansion and renewable energy procurement decisions. Future analysis should evaluate the possible attractiveness of non-WREZ resources compared to the WREZ resources considered here, while recognizing that non-WREZ resources may require lower voltage transmission lines.

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 west. 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 2 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.

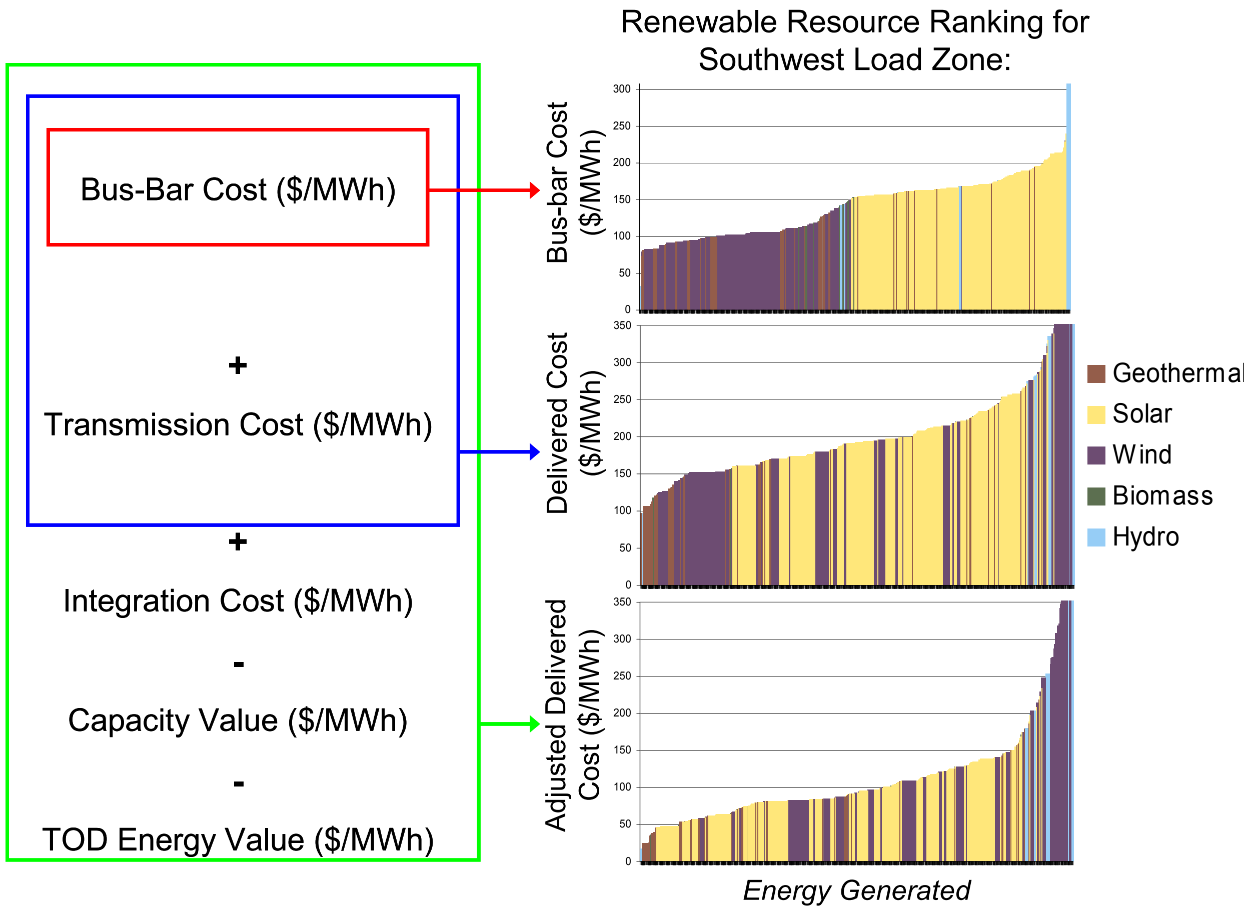


Figure 2. Framework for evaluating the economic attractiveness of renewable resources to load zones in the WREZ model

2.2 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. A summary of a subset of these various input parameters, as well as the resulting bus-bar costs, is provided in Table 2. The range in capital cost, capacity factor, and bus-bar costs reported in Table 2 within any individual renewable resource type reflect ZITA and Black & Veatch assumptions about variations in cost drivers across renewable resource sites.

Table 2. 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)

In addition to the data summarized in Table 2, we used the following assumptions in our base case analysis:

- All projects are assumed to be financed with independent power producer (IPP) financing assumptions, with a somewhat more aggressive debt-term assumed for solar technologies than for other renewable technologies.[8]
- All solar resources in the base case analysis are assumed to be wet-cooled solar thermal electric facilities with six hours of thermal storage.
- The 30% investment tax credit (ITC) is available to all renewable resources built in the United States.[9] A slightly less attractive tax credit is available in Mexico. Accelerated depreciation, similar to the accelerated depreciation available to renewable resources in the United States, is assumed for Canadian resources.
- Capital costs reported in Table 2 represent the total cost of the renewable generation facility as estimated by ZITA and include costs to interconnect to the nearest high-voltage (115 kilovolt [kV] or above) transmission substation. Capital costs vary for the wind and solar technologies due to the distance of the resource to the nearest substation. Capital costs vary for geothermal and biomass projects because of distance and assumed plant size (larger plants are cheaper). The capital costs of hydropower plants vary based

[8] The IPP financing assumptions include a 60% debt/40% equity financing structure, a debt interest rate of 8%, a target equity return on investment of 15%, a 15–year debt term for all non-solar technologies, and a 25-year debt term for all solar technologies. The longer debt term for the solar technologies was a decision made by the ZITA group "based on stakeholder input" (Pletka and Finn, 2009).

[9] The 30% investment tax credit is set to expire for all renewable resources. Solar and geothermal, however, are eligible for a 10% investment tax credit that has no explicit expiration date under federal law. We assume all wind resources would use the 30% ITC rather than the PTC. Bolinger et al. (2009) find that wind resources with capital costs around $2,400/kW and capacity factors of 31% prefer the ITC over the PTC. Lower capital costs and higher and capacity factors, however, will tend to make the PTC more attractive than the ITC for wind. We do not consider this choice on a project by project basis, but it may be important in more detailed analysis.

on distance, plant size, and type of plant (incremental upgrades to existing dams are cheaper, new run-of-river projects are the most expensive) (Pletka and Finn, 2009).

- All costs are reported in 2008 constant dollars.

2.3 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 model includes several different transmission line choices ranging from a single-circuit 230 kV line to a single circuit 765 kV line. As a starting point, and in our base case results, the model uses a single-circuit 500 kV line with 1500 MW of transmission capacity. The cost of transmission is proportional to the length of the line, while the distance between resource hubs and load zones is primarily based on existing transmission corridors or rights of way. The transmission costs also include right-of-way costs, operating costs, and substation costs for substations that are added, on average, approximately every 150 miles (mi). The capital cost and transfer capacity rating assumptions for the 500 kV line leads to a total transmission capital cost of $1,564/MW-mi.[10]

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.[11] As a result, a 100 MW renewable project is assumed to pay the same amount for transmission on a dollar per kilowatt-year ($/kW-yr) basis as a renewable projects that is 1500 MW and is able, individually, to fully subscribe a 500 kV transmission line. In reality, of course, 500 kV transmission lines can be built in 1500 MW increments but cannot be built in 100 MW increments. If the only attractive renewable resource in a WREZ hub has a nameplate

[10] The capital cost includes a 10% Allowance for Funds Used During Construction [AFUDC] rate. This capital cost is levelized assuming a 60% debt/40% equity financing structure, a debt interest rate of 7%, a target equity return on investment of 11%, and a 20–year debt term.

[11] 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, as discussed in the next footnote.

capacity of 100 MW then transmission planners would build a much lower-voltage transmission line (below 230 kV), resulting in a much higher cost on a $/kW-yr basis. 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.

The pro-rata allocation assumption based on the capacity of the resource further assumes that transmission costs on a $/kW-yr basis are equivalent between baseload resources such as geothermal and variable resources like wind. As a result, the utilization of transmission[12] is always lower for a low capacity-factor resource than it is for a baseload resource, increasing the cost of transmission on a per-MWh of electricity basis for these lower capacity-factor technologies. This assumption may overstate the cost of transmission for low capacity-factor resources in cases where the availability of transmission-congestion management products allow fuller utilization of transmission lines (Stoft et al., 1997), including the use of economic redispatch, non-firm transmission access, and conditional-firm transmission.[13]

[12] *Utilization* is defined in this case as the ratio of the actual energy sent over a transmission line relative to the energy that could be sent over the transmission line if power equivalent to the transfer rating of the transmission line were always transferred over the line. In the case that there are no curtailments and only a single resource is transmitted over a line, the utilization of the line will be equivalent to the capacity factor of the resource.

[13] It is often suggested that flexible resources, such as natural gas plants or storage, could be sited near renewable resources and operated in a way that would "fill-in" the unused transmission capacity during times when the variable resource was not at its full capacity in order to increase the transmission utilization and decrease the cost of transmission for the variable generator. This approach, however, may have an opportunity cost associated with operating the flexible resource not to maximize its market value but to maximize transmission utilization. Further, siting the flexible resource far from the load zone it is serving will increase transmission losses relative to siting the plant at the load. A number of studies have examined the conditions under which these tradeoffs favor siting the flexible resource near the renewable resource rather than near the load (Phadke et al,, 2009, Denholm and Sioshansi, 2009). We examined an illustrative example of shipping Wyoming wind to Seattle that shows why simply siting a gas plant in Wyoming to increase the transmission utilization is not enough to justify lower transmission costs for wind. We sited 1500 MW of CCTG in Seattle and dispatched it to maximize the market value of the CCGT. The capacity factor of the CCGT was about 60%. We then added the cost of shipping 1500 MW of Wyoming wind over a 500 kV transmission line with a capacity factor and transmission utilization of 40%. The total energy-weighted adjusted delivered cost of the two resources was $42/MWh. We then removed the load sited CCGT and added 1500 MW of CCGT capacity in Wyoming that was dispatched around the Wyoming wind to create a flat block of power and a 100% utilization of the transmission from Wyoming to Seattle. The CCGT again had a capacity factor of about 60%, but a much different output profile than the 1500 MW CCGT sited in Seattle. The transmission cost for wind decreased by $48/MWh by sharing the cost of transmission between the wind and CCGT plant, but the overall adjusted delivered cost increased by $22/MWh to $64/MWh. If the natural gas price differential between Wyoming and Seattle for electric power were consistently over $3.5/MMBTU more in Seattle then the adjusted delivered cost of wind and the CCGT in Wyoming that is dispatched around the wind would be about equivalent to the adjusted delivered cost of building the CCGT in Seattle and shipping only wind over the line from Wyoming. This difference in natural gas prices is larger than the difference observed in 2007 for industrial customers (EIA, 2009 p. 56). We therefore suggest that much more detailed analysis is required before it is reasonable to simply assume that a flexible resource will be sited with the wind or solar plant to "fill-in" the transmission line.

The cost of line losses is also included in the delivered cost of each renewable resource. The cost of line losses is estimated based on the fact that the electricity lost through transmission lines is generated by the renewable resource but not delivered to the load zone. The assumed losses for the 500 kV line used in our base case analysis equals 0.7% for every 100 miles of line distance, and the cost of losses captures both the increased cost associated with purchasing renewable electricity that is not delivered to the load zone and the cost of the transmission capacity for electricity that eventually is lost.

2.4 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.[14] 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, the discussion in Appendix A suggests that 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.

2.4.1 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

[14] 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.

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., 2008; Fripp and Wiser, 2008; Lamont, 2008). Figure 3 provides an example in which the average marginal production cost across all hours for the Phoenix load zone is \$64.4/MWh, and wind and solar output profiles are considered. The TOD energy value is the sum of the hourly generation and the load zone's marginal production cost divided by the total energy generated. In the case presented here, the TOD energy value of solar is \$72.2/MWh and the TOD energy factor is 1.12. The TOD energy value for wind is lower, at \$63.6/MWh, with a TOD energy factor of 0.99.

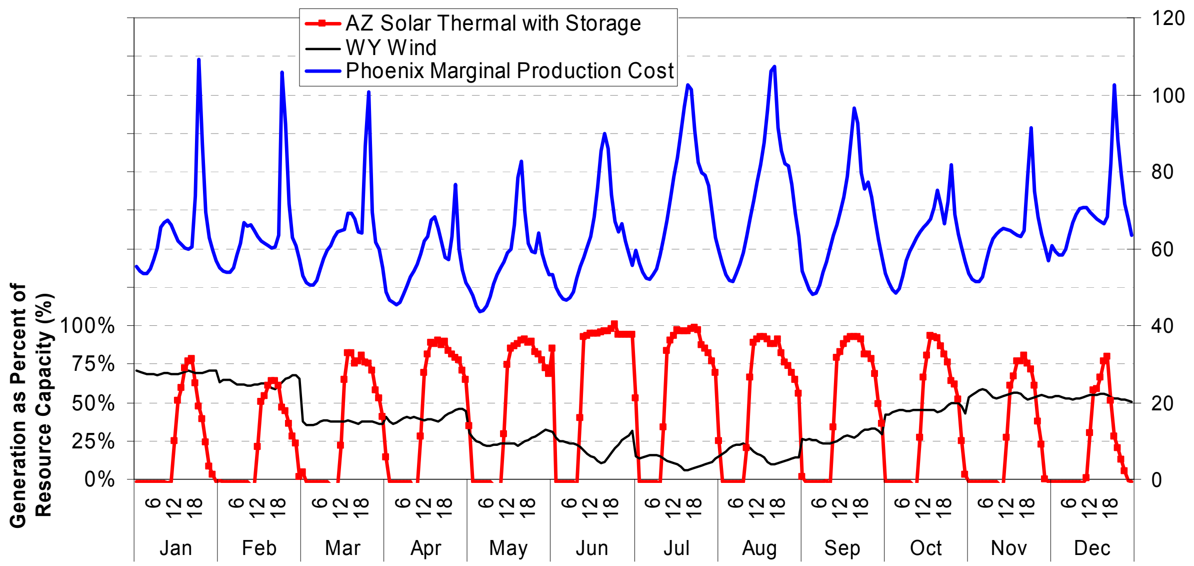


Figure 3. Example of TOD energy value comparison for WY wind and AZ solar thermal with storage for the Phoenix load zone

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. Biomass and some geothermal resources are assumed to have flat generation profiles. Flash geothermal resources have generation profiles that decrease with increasing ambient temperature, due to efficiency losses. Generation profiles for wind energy and solar technologies without thermal storage are modeled with historical meteorological data. Generation profiles for solar thermal with six hours of thermal storage are based on storage dispatch profiles that maximize the revenue to the plant for Southern California peak periods (Pletka and Finn, 2009).[15]

[15]Because the generation profiles of the solar thermal with thermal storage resources maximize the revenue for Southern California load zones, the profiles will not necessarily reflect the maximum value that solar thermal with storage will provide to all load zones in the WECC region. Based on some simple calculations, however, this does

The median, 10th, and 90th percentile of the TOD energy factor for each renewable resource considered in this report combined with the marginal production costs in each of the load zones is summarized for each renewable technology type in Table 3. The table also shows the TOD energy value assuming an annual average marginal production cost of $65/MWh. Solar technologies have the highest TOD energy factors while wind technologies have the lowest factors. Baseload renewable technologies, such as geothermal and biomass, have TOD energy values that are equal or nearly equal to average marginal production costs. For the median resource-load pair, solar technologies are found to be roughly $7/MWh more valuable than wind energy considering TOD energy value alone, while baseload technologies are found to be only slightly more valuable than wind, on average. Solar thermal technologies with thermal storage, again based on TOD energy value alone, are roughly $2/MWh more valuable than solar without storage.

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not appear to create a large bias in the results. Specifically, we used the 12 X 24 resource and load profiles from the WREZ resource database to create a simple "energy-balance" type solar thermal dispatch algorithm outside of the WREZ model. The algorithm uses the profile of a solar thermal plant with wet cooling and no storage to generate the resource input to a solar thermal plant with six hours of thermal storage and a solar field multiplier of around 2. The power block and storage are dispatched to maximize the capacity value and TOD energy value using any 12 X 24 series of marginal production costs and peak load periods. The energy balance method assumes that the thermal heat to thermal storage has a round-trip efficiency of 90%. We dispatched a Nevada solar thermal plant to the marginal production cost and load profile of Los Angeles. We then used the same dispatch profile to value that solar thermal plant to Portland, as is done in the WREZ model. To estimate the degree to which this assumption understates the value of solar thermal with six hours of storage to the Portland load zone, we then dispatch the Nevada resource to match the Portland profile and calculate the improved value of the plant. We find that the increase in capacity value and TOD energy value when optimally dispatching the solar thermal plant with six hours of thermal storage is on the order of just $1/MWh. While this is not a comprehensive assessment of the value of optimally dispatching thermal storage for different load zone characteristics, it does indicate that the assumptions in the WREZ model are appropriate for a screening level tool.

Table 3. TOD energy factor and TOD energy value for all renewable resource and load zone combinations in the WREZ model

	TOD Energy Factor		TOD Energy Value Assuming $65/MWh Average Marginal Production Cost ($/MWh)	
Technology	Median	(10th; 90th Percentile)	Median	(10th; 90th Percentile)
Hydro	1.01	(0.94 ; 1.12)	65.4	(60.9 ; 72.7)
Biomass	1.00	(1.00 ; 1.00)	65.0	(65.0 ; 65.0)
Geothermal	0.99	(0.98 ; 1.00)	64.4	(63.7 ; 65.0)
Wind	0.98	(0.86 ; 1.09)	63.4	(55.7 ; 70.8)
Wet Cooled Solar Thermal with Storage	1.09	(1.07 ; 1.13)	71.0	(69.5 ; 73.5)
Wet Cooled Solar Thermal without Storage	1.06	(1.04 ; 1.10)	69.0	(67.7 ; 71.4)
Dry Cooled Solar Thermal with Storage	1.09	(1.07 ; 1.13)	70.9	(69.4 ; 73.3)
Fixed PV	1.05	(1.04 ; 1.08)	68.3	(67.6 ; 70.3)

2.4.2 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,[16] we test the sensitivity of our results to the capital cost of a peaker plant in an alternative sensitivity case.

[16] 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. Recent forward capacity market auctions in ISO-New England (ISO-NE) resulted in capacity payments of only $54/kW-yr. The reliability pricing model results in the PJM power market lead to capacity prices of $40–90/kW-yr,

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). 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.[17] 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 being be similar to or potentially even higher than that of a baseload unit (Grubb, 1991; Stoft, 2008).

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depending on the zone within PJM. Forward capacity markets, however, are only meant to cover the portion of the fixed cost of new capacity that cannot be covered from revenues in energy markets. Because energy prices in real energy markets may rise above the marginal production cost of peaker plants due to scarcity pricing, the forward capacity market prices are expected to be somewhat lower than the resource adequacy cost we use in the WREZ model.

[17] 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.

The median, 10th, and 90th percentile of the ratio of the capacity credit to the capacity factor for each renewable resource combined with the load profiles in each of the load zones is summarized for each technology type in Table 4.[18] The table also shows the capacity value range of each renewable resource assuming a resource adequacy cost of $156/kW-yr. 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. These averaged values only apply to the median resource-load pairing, however, and as shown in the table, substantial variation in capacity value can exist within each individual technology category depending on the exact generation profile of the resource and the demand profile of the load zone.

[18] The median capacity credit for wind was 17% with a 10th and 90th percentile range of 11% to 42%, respectively. The lower end of this range corresponds with the capacity credit for wind in the West at 10-30% penetration on an energy basis (Lew et al., 2009) and the higher end of this range corresponds with the capacity credit estimated for wind with a transmission overlay in the Eastern Interconnection at 20-30% penetration on an energy basis (EnerNex Corp, 2010). The capacity credits for solar were similarly within the range expected based on results from more detailed analysis in the West (Lew et al., 2009).

Table 4. Ratio of capacity credit to capacity factor and capacity value for all renewable resource and load zone combinations in the WREZ model

	Ratio of Capacity Credit to Capacity Factor		Capacity Value Assuming $156/kW-yr Resource Adequacy Cost ($/MWh)	
Technology	Median	(10th; 90th Percentile)	Median	(10th; 90th Percentile)
Hydro	1.22	(0.28 ; 1.99)	21.7	(5.0 ; 35.4)
Biomass	1.00	(1.00 ; 1.00)	17.8	(17.8 ; 17.8)
Geothermal	0.76	(0.62 ; 1.13)	13.5	(11.1 ; 20.0)
Wind	0.55	(0.33 ; 1.44)	9.7	(5.8 ; 25.7)
Wet Cooled Solar Thermal with Storage	2.16	(0.77 ; 2.46)	38.5	(13.7 ; 43.7)
Wet Cooled Solar Thermal without Storage	1.70	(0.5 ; 2.28)	30.2	(8.8 ; 40.5)
Dry Cooled Solar Thermal with Storage	2.03	(0.82 ; 2.32)	36.1	(14.7 ; 41.3)
Fixed PV	1.27	(0.88 ; 1.68)	22.7	(15.6 ; 30.0)

2.4.3 Integration Cost

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).[19] Relatively few studies have investigated the integration costs for solar technologies

[19] As described in more detail in Section 4, 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

(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.

WECC-wide 33% RE case. Integration costs are often based on the assumption that sufficient transmission is available to allow balancing area cooperation or consolidation to mitigate wind integration challenges that would occur if small balancing areas attempted to balance large quantities of wind relative to the load in the balancing area (Lew et al., 2009). Integration costs may be much greater if a high degree of balancing area cooperation or consolidation was not available in the 33% RE target cases.

3. Drivers of Economic Attractiveness: Bus-bar Costs, Transmission, and Market Value Adjustments

In this section we compare the relative sensitivity of the adjusted delivered cost of different renewable technologies to changes in assumptions and input parameters. In so doing, this analysis helps provide a broad understanding of which attributes and uncertainties have the most affect on the relative economic attractiveness of renewable resources and which may warrant more detailed analysis. More specifically, we explore these sensitivities for three different renewable technologies, geothermal, wind, and wet-cooled solar thermal technology with six hours of thermal storage, and under three sets of alternative assumptions – base, low cost, and high cost. These alternative assumptions are summarized in Table 5.

As shown in the table, to test the sensitivity of the adjusted delivered cost to bus-bar costs, we vary capital costs, geothermal O&M costs, and the availability of the ITC. To test sensitivities to transmission assumptions, we vary transmission voltage, transmission distance, and transmission utilization assumptions. Finally, we test sensitivities to various market value adjustment factors by altering the input parameters for the capacity value, TOD energy value, and integration cost calculations. The resulting changes in the adjusted delivered cost relative to the base adjusted delivered cost for each of the three renewable technologies are shown in Figure .

As shown in the figure, the adjusted delivered cost of all three renewable technologies is highly sensitive to assumptions about bus-bar costs. Due to its relatively high capital cost, the adjusted delivered cost of solar thermal is the most sensitive to assumptions that affect bus-bar costs: the adjusted delivered cost of solar thermal increases dramatically with increased capital costs, lower capacity factors, and when the 30% ITC is not available. The adjusted delivered cost of wind and geothermal are also highly sensitive to capital cost assumptions and assumptions about the availability of the 30% ITC, but less so than solar thermal.

The relatively low capacity factors of wind and solar thermal technologies ensure that the adjusted delivered cost of these two technologies is highly sensitive to assumptions about the transmission voltage used to move power from the renewable resource region to the load zone and the required transmission distance. If options were available to increase transmission utilization for wind and solar to 60%, through better use of existing transmission capacity, non-firm transmission, economic redispatch, or conditional firm transmission, then the cost of long distance transmission for wind and solar would be significantly reduced, also improving the adjusted delivered cost of these resources. More detailed analysis would be required to identify situations under which utilization could be increased to 60% along with the costs associated with increasing utilization to this level. In contrast to wind and solar, geothermal is much less sensitive to transmission distance and voltage assumptions due to the high capacity factor of the resource and the resulting high utilization of the new transmission lines.

Variations to market value adjustment factors are found to impact the adjusted delivered cost of the three renewable technology options to a somewhat lesser extent than those parameters that impact bus-bar and transmission costs. Solar thermal has a high capacity value in most cases due to the strong correlation between solar thermal output and load. Some combinations of solar thermal and load zones, however, lead to a low ratio of the capacity credit to the capacity factor and substantially increase the adjusted delivered cost of solar thermal to those load zones. Similarly, assumptions about the cost of the avoided resource adequacy resource (i.e. the cost of the avoided peaker plant) can greatly affect the adjusted delivered cost of solar thermal energy. Wind energy, on the other hand, has a low capacity value in most cases, and the adjusted delivered cost of wind is therefore relatively insensitive to assumptions about the resource adequacy cost. There are a few cases where the ratio of the capacity credit to the capacity factor for wind is above one, for instance, combinations of load zones in the Pacific Northwest that have loads that peak during winter nights and wind resources that generate more power at night. In these cases, the adjusted delivered cost of wind can be reduced substantially. Changes in the assumed cost of wind integration, meanwhile, are found to have relatively little impact on the adjusted delivered cost of wind, relative to the other factors considered here. Finally, as a baseload resource with a relatively consistent output profile, the adjusted delivered cost of geothermal does not change significantly with variations in market value adjustment factors.

Table 5. Base, high, and low cost assumptions for adjusted delivered cost sensitivity analysis

	Low Cost	Base	High Cost
Bus -Bar Costs			
Resource Capital Cost	Decrease base capital cost by 30%	Median capital cost from Table 2	Increase base capital cost by 30%
Variable O&M	Minimum variable O&M cost for geothermal plants	Median variable O&M cost for geothermal	Maximum variable O&M cost for geothermal plants
Capacity Factor	90th percentile of capacity factor from Table 2	Median capacity factor from Table 2	10th percentile of capacity factor from Table 2
ITC Availability		WREZ model starting point assumption that ITC is available	30% ITC is not available, 10% ITC is available for solar and geothermal
Transmission Cost			
Transmission Voltage	500 kV Bi-pole HVDC transmission line cost and losses	WREZ model starting point assumption of 500 kV single circuit transmission line cost and losses	345 kV single circuit transmission line costs and losses
Distance	50 mile distance	400 mile distance from renewable resource to load zone	900 mile distance
Utilization	60% utilization for wind and solar,90th percentile capacity factor from Table 2 for geothermal	Median capacity factor from Table 2	
Capacity Value			
Ratio of Capacity Credit to Capacity Factor	90th percentile from Table 4	Median from Table 4	10th percentile from Table 4
Resource Adequacy Cost	Change assumption to $200/kW-yr	WREZ model starting point assumption of $156/kW-yr levelized cost	Change assumption to $100/kW-yr
TOD Energy Value			
TOD Energy Factor	90th percentile from Table 3	Median from Table 3	10th percentile from Table 3
Average Energy Price	Maximum average marginal production cost across load zones	Median average marginal production cost across load zones	Minimum average marginal production cost across load zones
Integration Costs	$1/MWh for wind	WREZ model starting point assumption of $5/MWh for wind	$10/MWh for wind

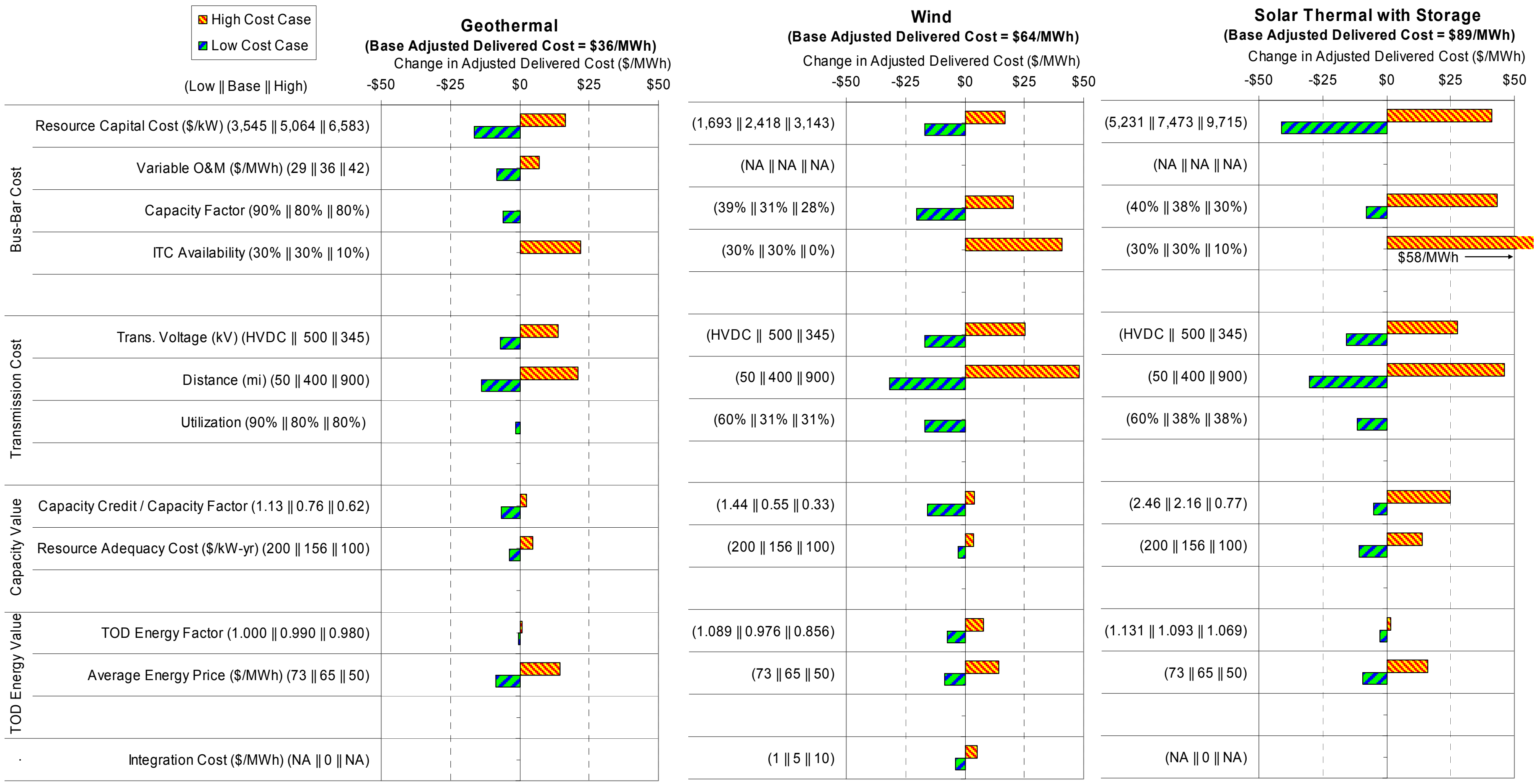


Figure 4. Sensitivity of adjusted delivered cost for geothermal, wind, and solar thermal with storage technologies to changes in key drivers

4. Results: Base Case and Alternative Scenarios

In this section we move from exploring each driver of the adjusted delivered cost individually for different renewable resource technologies to determining most economically attractive portfolios of WREZ-identified resources to meet overall WECC-wide renewable energy demands. In particular, the WREZ model[20] was used 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 (we assume that all WREZ resources are eligible for all load zones), resource set-asides or carve-outs (we assume no such set-asides), and local preference multipliers or in-state/region requirements (we assume no such preferences, though we do conduct sensitivities around the use of RECs). 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.

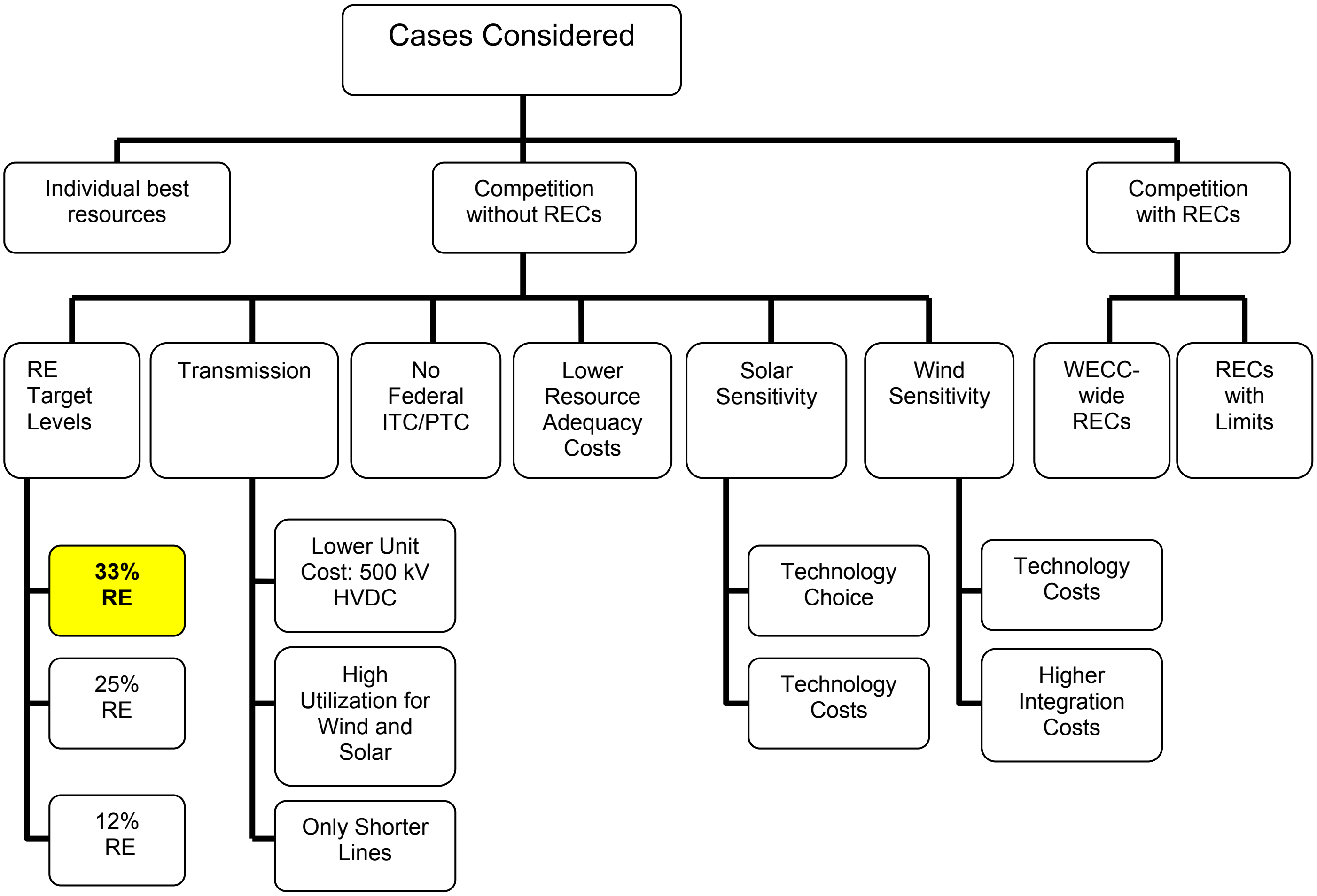
In addition to reporting Base case model results, a key objective of this section is to assess the sensitivity of those results to various assumptions and input parameters. As such, the results of a large number of alternative cases are presented, as illustrated in Figure 5. As suggested by the figure, we begin by identifying the WREZ resources that the model determines that load zones would procure if there was no competition for resources with other load zones and each load zone met a 33% RE target by the year 2029: the "individual best resources" case. In this case, load zones are assumed to procure the WREZ-identified resources that are most economically attractive for delivery to their location, and any double counting of the same WREZ resource for multiple load zones is ignored. This analysis helps identify specific WREZ resources and resource hubs that are attractive enough to potentially solicit more interest from load zones than there is available resource.

Because load zones will compete for these attractive but scarce resources, all other cases allocate renewable supply to load zones in such a way as to minimize aggregate WECC-wide renewable energy supply costs: the "competition" cases, with and without RECs. The mechanism by which resources are allocated to load zones is described later.

Focusing first on the "Competition without RECs" cases, all of these 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. Among the many cases that fall within this category, 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

[20] Specifically, the WREZ Peer Analysis Tool, which allows a user to determine the relative economic attractiveness of all renewable resources identified in WREZ hubs from the perspective of each of the load zones, was used in this analysis. The WREZ process also developed the Generation and Transmission Model, which allows users to compare a limited portfolio of user-selected renewable resources and allows one to more-readily consider the lumpiness of transmission investment.

resources. After conducting this assessment of three different RE target levels, we select the 33% "Competition without RECs" case as the Base case to which all other scenarios are compared.



Note: Other than the cases that specifically evaluate different RE target levels, all other cases meet a WECC-wide 33% RE target.

Figure 5. Schematic of alternative cases evaluated with the WREZ model

After selecting the 33% "Competition without RECs" case as the Base case, we then consider a wide range of alternative scenarios that vary key parameters and assumptions. Continuing with the "Competition without RECs" sequence, we first focus on four sensitivities related to transmission, resource adequacy costs, and federal policy:

- **HVDC Long Lines:** What if the unit cost of transmission for wind and solar resources that require lines longer than 400 miles are lower due to the use of 500 kV HVDC Bi-pole lines instead of the single-circuit 500 kV lines assumed in the Base case?[21]

[21] 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. We found that this is assumption was reasonable in

- **High Utilization:** What if wind and solar are able to increase the utilization of new transmission to 60% through better use of existing transmission or better congestion management techniques, thereby reducing the allocated cost of transmission to these resources relative to the Base case in which utilization is assumed to equal the capacity factor of a resource?
- **Short Lines:** What if transmission expansion was limited to shorter lengths between load zones and resource centers? In particular, we limit lines to 400 miles in length for all load zones except for Seattle and San Francisco, which are both allowed to build up to 700 mile lines due to insufficient WREZ resources within a 400 mile radius.
- **No Federal ITC or PTC:** What if the Federal 30% ITC and production tax credit (PTC) are not available by the time new transmission is built to WREZ resources, as is assumed in the Base case, and instead only the 10% ITC is available to new solar and geothermal resources?
- **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) due to new technologies including demand response, or a reduction in the cost of gas turbines?

Our Base case scenario assumes that all solar deployment occurs with wet-cooled solar thermal technology with six hours of thermal storage. Because a variety of different solar technologies are available and are vying for market share, we evaluate three cases that replace the Base case solar resource with an alternative solar technology:

- **Solar Thermal, Dry Cooling with Storage:** What if all solar deployment comes from dry-cooled solar thermal technology with storage instead of using wet cooling?[22]
- **Solar Thermal, Wet Cooling without Storage:** What if all solar deployment comes from wet-cooled solar thermal technology, but with no thermal storage?
- **Fixed PV:** What if all solar deployment comes from fixed-plate PV systems rather than solar thermal plants?

For the Base case in which all solar is assumed to be solar thermal plants with six hours of thermal storage and wet cooling, we also tested the importance of the Base case assumption of a longer debt term for solar technologies than for any of the other WREZ-identified renewable resources. Additionally, we examined the implications of solar technology cost reductions relative to all other renewable technologies:

- **Equal Solar Finance:** What if the wet cooled solar thermal technology with six hours of thermal storage had a debt term equal to the debt term of the other renewable technologies of 15 years rather than the 25 year debt term assumed in the Base case?
- **Low Cost Solar Thermal:** What if the capital costs of the Base case solar thermal technology are 70% of today's cost, while none of the other renewable technologies experience cost reductions?
- **Low Cost Fixed PV:** What if the capital costs of the fixed-plate PV resource are 70% of today's cost, while none of the other renewable technologies experience cost reductions?

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that 89% 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 HVDC Long Lines case.

[22] This is a particularly relevant question due to concerns about the availability of cooling water for solar thermal plants in the desert southwest (Woody, 2009)

Still continuing the "Competition without RECs" scenario sequence, we then test the sensitivity of our Base case results to wind capital and integration cost assumptions:

- **Low Cost Wind:** What if the capital cost of wind is 70% of today's cost, while none of the other renewable technologies experience cost reductions?
- **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)?

As noted earlier, all of the cases described above 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%:

- **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:** Given the expectation that meeting more than 33% of the annual demand for any load zone with a single renewable energy technology will be difficult given concerns about integration at high penetration, 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?

4.1 Individual Best Resources Case, and Allocation of Resources to Load Zones

We begin by using the WREZ model to rank renewable resources by their economic attractiveness to all load zones in the WECC region, ignoring the possibility of competition for scarce resources (the "Individual Best Resources" case). As shown in Table 6, at a 33% RE demand level, there are multiple load zones that find a number of the same high-quality (but limited-quantity) WREZ resources to be attractive. For instance, every load zone but one in the WREZ model finds the hydropower resources characterized in Washington State[23] to be economically attractive. Similarly, geothermal resources in southern California, northern Nevada, and Oregon are found to be potentially attractive to several load zones on the West Coast for meeting RE targets. Among the wind resources characterized in the WREZ process, large quantities in Montana and Wyoming are found to be desirable to multiple load zones: Montana resources to the Billings, Seattle, Vancouver, and Calgary load zones, and Wyoming wind resources to the Casper and Boise load zones. Interestingly, none of the solar resources characterized in the WREZ process are over procured in this Individual Best Resources case; this result is in part due to the significant potential of multiple solar resource hubs near Southwestern load centers (i.e., scarcity of solar is not a problem when the other high-quality resources are double-counted by multiple load zones), and in part to the fact that solar is not found to be competitive with other resources when transmitted over long distances.

[23] Specifically, the resource was WA_SO_H_1 in the WREZ database. This resource represents incremental additions of capacity to existing powered dams. Although this resource is economically attractive to 19 of the 20 load zones, not all of the load zones currently allow this type of resource to qualify for their state's RPS.

Table 6. WREZ resources that are over procured in a 33% RE demand case, when competition for limited quantity resources is not accounted for in the Individual Best case

WREZ Resource	Resource Type	Nameplate Capacity of Available Resource (MW)	Individual Best Case: Nameplate Capacity of Resource Procured (MW)	Individual Best Case: Over procurement (% of Available Resource)	Individual Best Case: Number of Load Zones that Procure Resource
BC_WC_G_3	Geothermal	180	360	100%	2
BC_WC_H_5	Hydro	907	1,079	19%	2
CA_SO_G_3	Geothermal	232	696	200%	3
CA_SO_G_4	Geothermal	1,170	4,899	319%	6
CA_WE_B_4	Biomass	74	148	100%	2
CA_WE_W_2	Wind	198	395	100%	2
MT_CT_W_2	Wind	509	2,034	300%	4
MT_CT_W_3	Wind	2,021	5,267	161%	4
NV_EA_B_4	Biomass	133	266	100%	2
NV_NO_G_3a	Geothermal	109	654	500%	6
NV_NO_G_3b	Geothermal	268	2,304	760%	9
NV_NO_G_4	Geothermal	200	364	82%	2
NV_NO_G_4a	Geothermal	148	444	200%	3
NV_WE_G_3	Geothermal	132	792	500%	6
OR_NE_B_4	Biomass	388	776	100%	2
OR_SO_G_3a	Geothermal	384	2,043	432%	6
OR_SO_G_4	Geothermal	64	192	200%	3
OR_WE_B_4	Biomass	102	204	100%	2
OR_WE_G_3	Geothermal	315	3,308	950%	11
OR_WE_W_3	Wind	301	904	200%	3
UT_WE_B_4	Biomass	87	348	300%	4
UT_WE_G_3	Geothermal	90	450	400%	5
WA_SO_B_4	Biomass	75	150	100%	2
WA_SO_H_1	Hydro	544	9,930	1725%	19
WY_EC_W_2	Wind	1,502	2,590	72%	2

Given these results, it is clear that if each load zone were to act in isolation, there would be numerous instances in which multiple zones would hope to procure the same high-quality but scarce renewable resource. Because the total developable quantity of these attractive resources is limited, for the remaining cases presented in this report, we need to 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 (i.e., no load zones have monopsony power, and no resource developers have monopoly power), 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 will ensure that any individual renewable resource will be allocated to the load zone that has the most economic benefit from its use.[24] 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,[25] subject to the achievement of load-zone RE targets and given limited renewable resource quantities.[26] A more detailed description of this competitive resource allocation mechanism and an example of its application to the Washington hydropower resource is available in Appendix B. The remainder of the results presented in this paper rely upon this allocation system.

4.2 Impact of the Level of Renewable Energy Demand

Using the competitive resource allocation mechanism, and assuming "Competition without RECs," we first investigate the resource selection, transmission expansion, and cost implications of three different RE target levels throughout WECC for the year 2029. The lowest RE target, 12%, is roughly equal to the aggregate quantity of new renewable energy required to meet RE demand from existing RPS policies in the west by 2029.[27] With increased pressure on decarbonizing the electricity sector, however, RE targets may rise beyond current legislative mandates. We evaluate the implications of such an increase in renewable energy demand by imposing both a 25% and 33% RE target on all load zones in the WECC region. In each instance, we assume that new resources must be physically delivered to load zones via new transmission investment and do not allow the use of renewable energy credits. Base case assumptions are employed in all three of these cases. The impact of increased RE targets on the composition of renewable resource procurement, transmission expansion, and resource supply costs are summarized in Table 7. Note that the amount of renewables shown in these results, as well as in all of the results that follow, is the incremental renewable additions above the existing level of renewable energy supply already available in the WECC.

As shown in the table, increasing the level of the RE target changes the relative composition of the renewable energy that is procured. Although wind contributes the largest share to the renewable portfolio for all three RE targets levels under the present Base case assumption, the combined geothermal, biomass, and hydropower resources contribute almost as much as wind in the 12% RE case. These combined resources, however, do not dramatically increase as the renewable demand increases from the 12% RE case to the 33% RE case. In fact, while renewable demand increases by 270% from the 12% RE case to the 33% RE case, the combined contribution of geothermal, biomass, and hydropower increases by only 78%. The limited increase in these resources is partially explained by the observation that 45% of the available

[24] Since these resources are limited but attractive to multiple load zones, loads may try to act quickly to secure these resources before renewable demand increases. Greater competition for the limited resources will, however, eventually make the resource too expensive for all but the load zone that is willing to pay the most to secure the resource to meet its renewable demand.

[25] In particular, we find the solution that minimizes the energy-weighted average adjusted delivered cost WECC-wide.

[26] We developed an Excel-based extension to the WREZ model that finds the competitive allocation of renewable resources to load zones using a premium version of the Excel Solver tool.

[27] 2029 load forecasts are derived by applying Energy Information Administration (EIA) AEO2009 projected annual growth rates (at the level of electricity market module [EMM] regions) to actual 2007 state retail sales (from EIA). Allocation of load forecasts and existing renewables to WREZ load zones are from personal communication with Galen Barbose of Lawrence Berkeley National Laboratory, September 4, 2009.

geothermal, biomass, and hydropower resources in the WREZ hubs are procured by a load zone even at the modest 12% RE level. At the 33% RE level, 81% of the total available hydropower, biomass, and geothermal resources are procured by load zones. The geothermal resources identified in WREZ hubs in particular are fully allocated at the 25% RE level and remain fully utilized at the 33% RE level. These resources are therefore largely constrained by the total resource quantity assumed to exist in the renewable energy hubs characterized during the WREZ process, not by economic consideration. In comparison, only 16% of the available wind resource and virtually none of the solar resource are procured by load zones at the 12% RE level, under Base case assumptions; these figures grow to only 54% and 31% of the available wind and solar resource, respectively, at the 33% RE target level. Though overall renewable resource composition estimates are heavily driven by input assumptions, the results presented here tell a story of increased competition between wind and solar as RE demands increase and the most attractive wind resources are depleted, while other renewable technologies may be more constrained by resource availability than by economic factors alone.

Because the most economically attractive renewable resources are selected by load zones at the 12% RE level, the resources that are procured as the RE level increases become relatively less economically attractive, thereby increasing overall supply costs.[28] The average adjusted delivered cost represents the energy-weighted adjusted delivered cost of resources procured to meet RE demands on a WECC-wide basis. 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 RE were increased a small amount. (These marginal costs therefore also indicate the minimum adjusted delivered cost that non-WREZ resources would have to achieve to economically substitute for the WREZ resources included in the present analysis). Wind energy is found to be the largest resource that is added when the RE level increases from 12% to 25%. Further increasing the RE level from 25% to 33%, however, begins to deplete the most economically attractive wind resource areas, and a nearly equivalent amount of solar begins to be procured. Average adjusted delivered costs increase by $14/MWh and marginal costs increase by $21/MWh when the RE level increases from 12% to 25%. Further augmenting the RE level from 25% to 33% increases average costs by an additional $6/MWh and marginal costs by an additional $7/MWh.

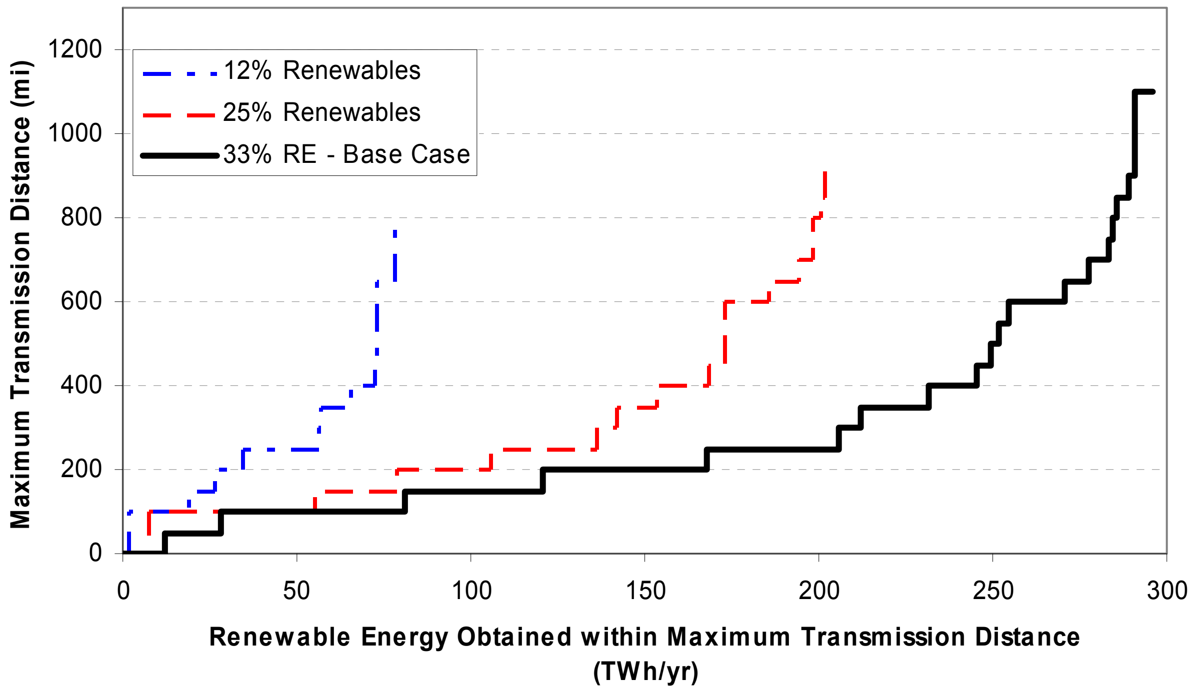
[28] This cost increase as the RE demand increases is dependent on our treatment of transmission costs. In reality, RE costs could be greater at lower RE targets if the lumpiness of transmission were to be explicitly accounted for in the model. A high-quality resource region that is only attractive if the amount of resource developed is large enough to justify a 500 kV transmission line may not be sufficiently attractive at a low RE level, due to the smaller quantity of renewable resource being procured. This distinction between the "supply-curve" effect and the "economies of scale" effect is discussed by Mills et al. (2009).

Table 7. WECC-wide impact of increasing RE 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%	

This increase in costs is, in part, due to the transmission investment needed to meet increasingly stringent renewable energy targets. At the 12% RE target, the transmission investment is about $6 billion. As incremental RE demand increases by 170% from the 12% RE level to the 25% RE level, new transmission capacity and the required transmission investment increase by 190%. The total transmission investment for the 25% RE target is $17 billion. Similarly, as RE demand increases by 39% from the 25% RE case to the 33% RE case, new transmission capacity increases by 55%. The total transmission investment in the 33% RE case increases to $26 billion. At all RE levels the cost of transmission and losses are only a small portion (around 15%) of the total delivered cost.

Interestingly, though more energy is procured over long transmission lines at the 33% RE target level, there are some long distance lines that are found to be economically attractive even at the lower 12% and 25% RE levels. 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. As illustrated by this figure, rather than only adding resources that are farther away as renewable targets increase, some closer renewable resources, such as solar in the Southwest, become more economically competitive as renewable target levels increase.



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 at the 12%, 25%, and 33% RE levels

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

As a base case for comparison with several alternative scenarios, we chose the 33% RE case, in which 33% of the annual load in each load zone is provided by renewable energy delivered to that load zone. Here we explore the Base case results in more detail before evaluating alternative scenarios. The full results for the base case are available in Appendix D.

4.3.1 Base Case Resource Composition

In the Base case, a significant portion (49%) of the incremental renewable energy added to meet a WECC-wide 33% RE target is found to be wind energy, leading to a WECC-wide wind penetration of 16% on an energy basis.[29] 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 (Figure 7). Nine of the 20 load zones are found to select

[29] The incremental wind added to reach a 33% RE target leads to a 14% penetration of wind. Adding the estimated existing wind generation in WECC of about 20 TWh/yr increases the overall penetration to 16% WECC wide.

100% wind energy to meet their 33% RE target, when constrained to purchase only from WREZ-identified renewable energy resource hubs.

The second largest renewable resource type in the Base case is solar (assumed in this case to be wet-cooled solar thermal technology with six hours of thermal storage), which makes up 29% of incremental renewable energy demand, leading to a WECC-wide energy penetration level of 8%. Solar energy is found to constitute 100%, 66%, and 56% of Arizona's, Nevada's, and California's incremental RE demands, respectively. No other states, however, are found to rely on solar energy to meet the 33% RE target under the Base case assumptions. The remaining technologies provide the remaining 22% of the energy required to meet incremental RE demand. Geothermal, biomass, and hydropower provide 10%, 7%, and 6% of the total incremental RE demand, respectively. Geothermal energy is procured by load zones in Nevada, California, Utah, Washington, and British Columbia. Biomass is procured by loads in Utah, California, Washington, and British Columbia. Hydropower is only procured by loads in Washington and British Columbia. As mentioned earlier, these technologies are largely limited by the assumed level of resource availability in the WREZ-identified RE hubs, and less by economic factors.

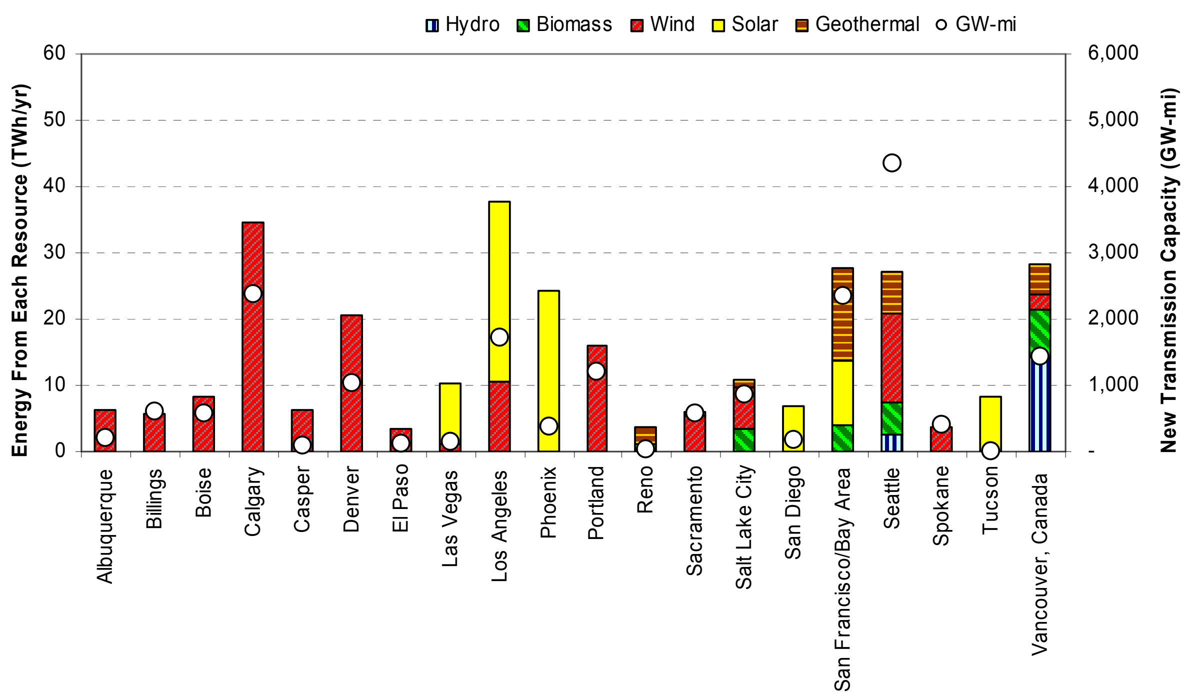


Figure 7. Resource selection and new transmission expansion for each load zone in achieving a 33% RE target by 2029 (Base case)

4.3.2 Base Case Transmission Expansion

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 18,510 GW-mi (Figure 8).[30] The

[30] The transmission capacity in GW-mi is calculated as the product of the transfer capacity of the transmission and the transmission distance between the resource hub and the load zone that procures the renewable resource. 500

total capital investment required for this transmission is estimated at approximately $26 billion. 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.” Specifically, in this case, 57% of the renewable energy procured is within 200 miles, 83% is within 400 miles, and 91% is within 600 miles of the purchasing load zone (Figure 9).[31] The energy-weighted average transmission distance is 245 miles. The fact that a majority of the renewable energy is procured over relatively short transmission lines is an important finding given the number of transmission proposals in the West intended to connect very distant resource regions to load zones (Mills et al., 2009). Though long-distance transmission lines are found to be economically attractive in some cases, these long lines will need to be accompanied by significant investment in a large number of lines on shorter transmission paths if cost minimization is a key objective. Moreover, it deserves reiteration that our analysis focuses exclusively on WREZ-identified resource hubs; were non-WREZ resources considered, transmission expansion needs would be expected to decline. Of course, the results presented here are based on a simplified screening tool and should not be used to justify or deny specific transmission investments. The results do, however, highlight the important considerations that need to be evaluated when identifying specific transmission investment strategies.[32] The sensitivity of the economic attractiveness of different renewable resources and the associated transmission expansion can be visualized by comparing the Base case transmission map in Figure 8 to similar maps from other scenarios presented in Appendix C.

Transmission expansion in the Base case is found to be driven largely by five load zones: Calgary, Los Angeles, San Francisco, Seattle, and Vancouver (Figure 7). These five load zones are responsible for 66% of the estimated transmission expansion in GW-mi terms, due in part to the large demand for RE and in part to the relative lack of sufficient economically attractive nearby resources in the modeled renewable resource hubs.[33] Seattle procures some Washington and Oregon renewable resources, Nevada and Idaho geothermal, and wind from Montana and Wyoming. San Francisco procures the bulk of its renewable energy from southern California solar and geothermal resources and a lesser amount of geothermal from Oregon. The other three load zones procure significant amounts of renewable energy from closer resources: Calgary

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MW of wind that is procured from a resource hub that is 200 miles from a load zone, for example, will require 100 GW-mi of new transmission capacity. We do not determine the total circuit miles of new transmission in this study because that requires developing rational transmission plans that account for the lumpy nature of transmission, which contrasts with our pro-rata transmission cost allocation assumption.

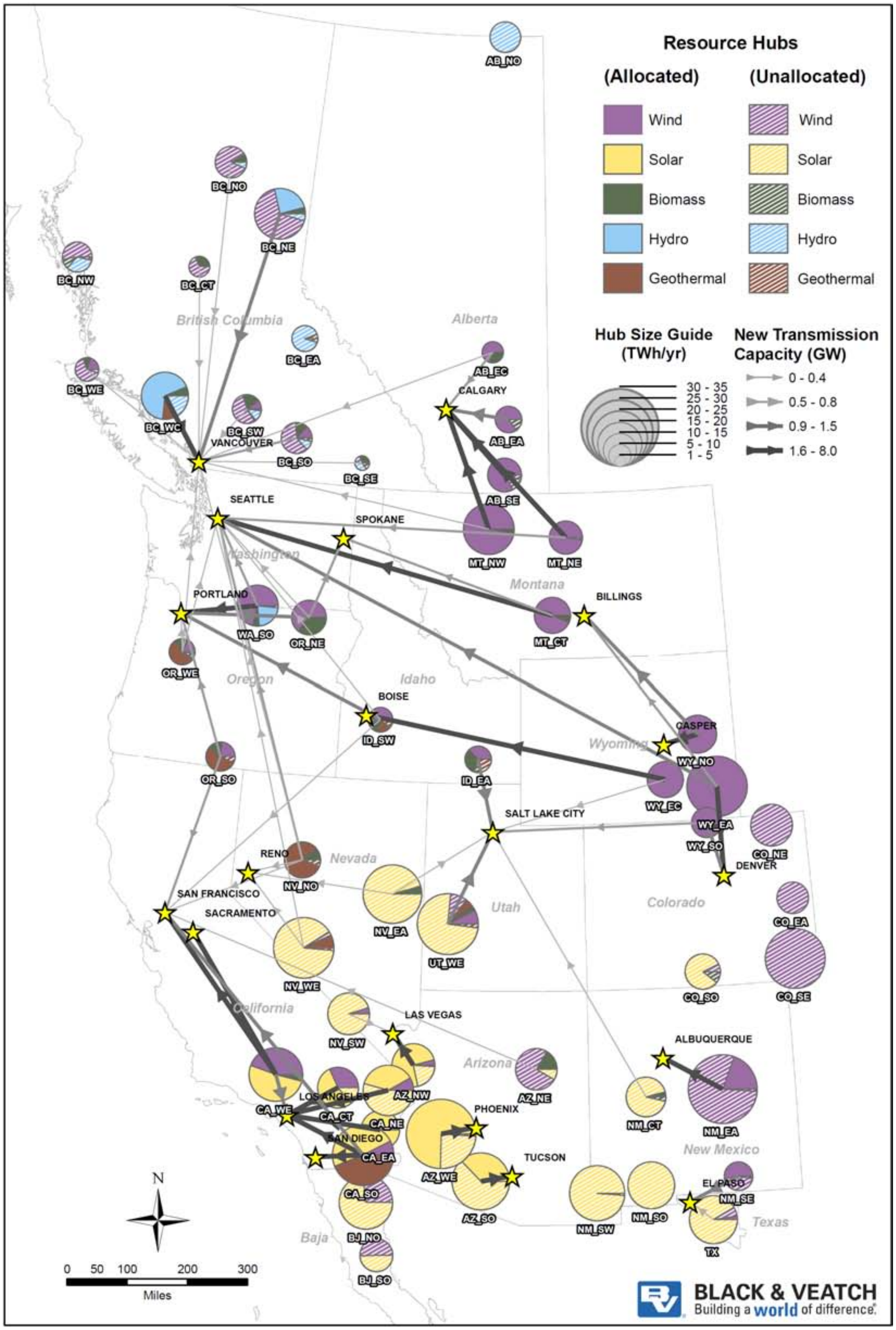
[31] Or put another way: 57% is within 200 miles, 26% is between 200 miles and 400 miles, 8% is between 400 miles and 600 miles, and 9% is further than 600 miles.

[32] The significant reliance on shorter transmission paths may be due to our assumption that all loads are simultaneously procuring renewable resources to meet a 33% RE target in a competitive manner. In reality, there is not a uniform WECC-wide RE target and there are first-mover advantages that may lead load zones to long lines to procure the most attractive resources before other load zones begin to procure RE resources.

[33] The average (energy-weighted) transmission distance for resources procured by San Francisco and Seattle are 484 miles and 668 miles, respectively. The average distance between the resources and loads for San Francisco and Seattle is much longer than those for Vancouver, Calgary, and Los Angeles—279 miles, 219 miles, and 147 miles, respectively. The large transmission capacity in GW-mi in the latter cases is driven more by the amount of resource procured over new transmission lines (the GW portion) rather than the distance between the resource and the load zone (the mi portion).

procures significant amounts of Alberta and Montana wind, Vancouver primarily procures hydro from British Columbia, and Los Angeles procures wind and solar from southern California.

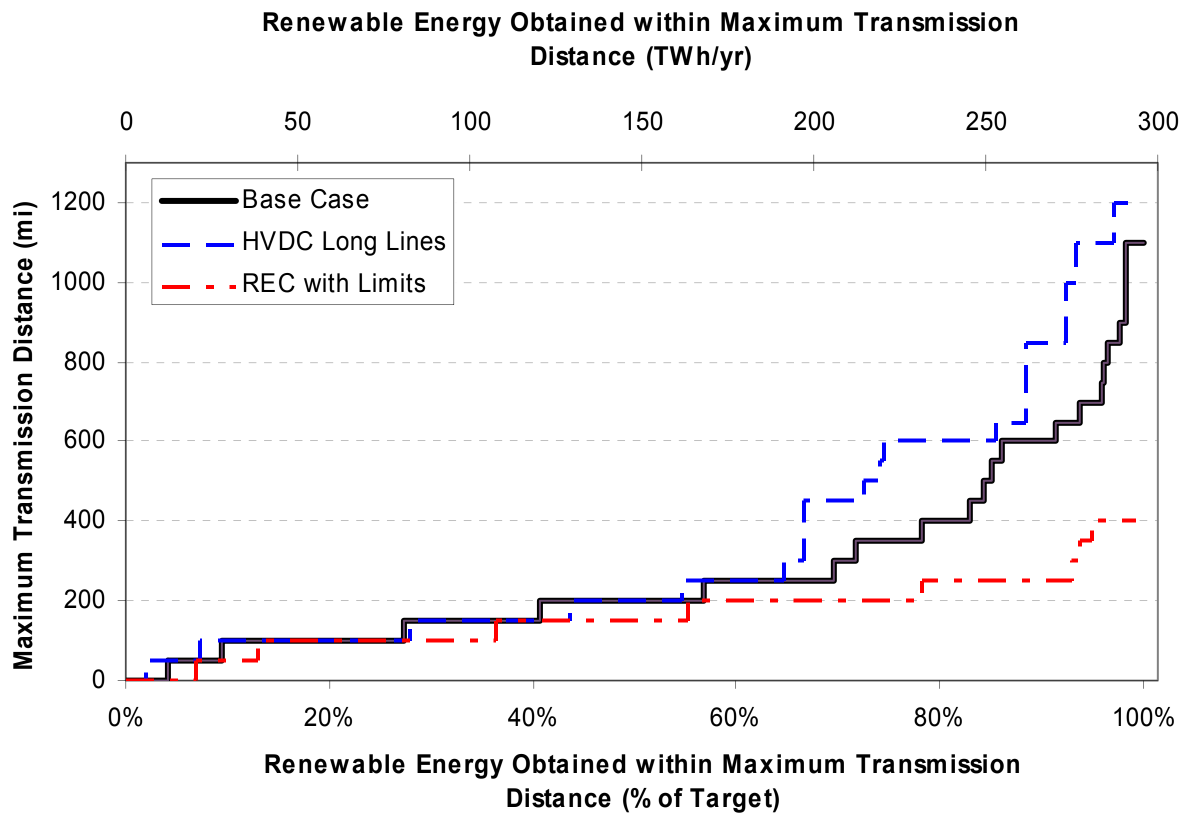
The technology that is found to require the most new transmission is wind energy (Figure 10). Wind is responsible for 63% of the transmission expansion on a GW-mi basis, while it provides 49% of the renewable energy. Solar energy, on the other hand, is found to require much less transmission due to the fact that solar is only used by load zones in the Southwest that are located near high-quality solar resources: solar is responsible for 16% of the transmission expansion while it provides 29% of the total incremental energy. The other renewable technologies require transmission capacity roughly in proportion to the amount of energy that they provide.



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



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

Figure 9. 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

4.3.3 Base Case Costs

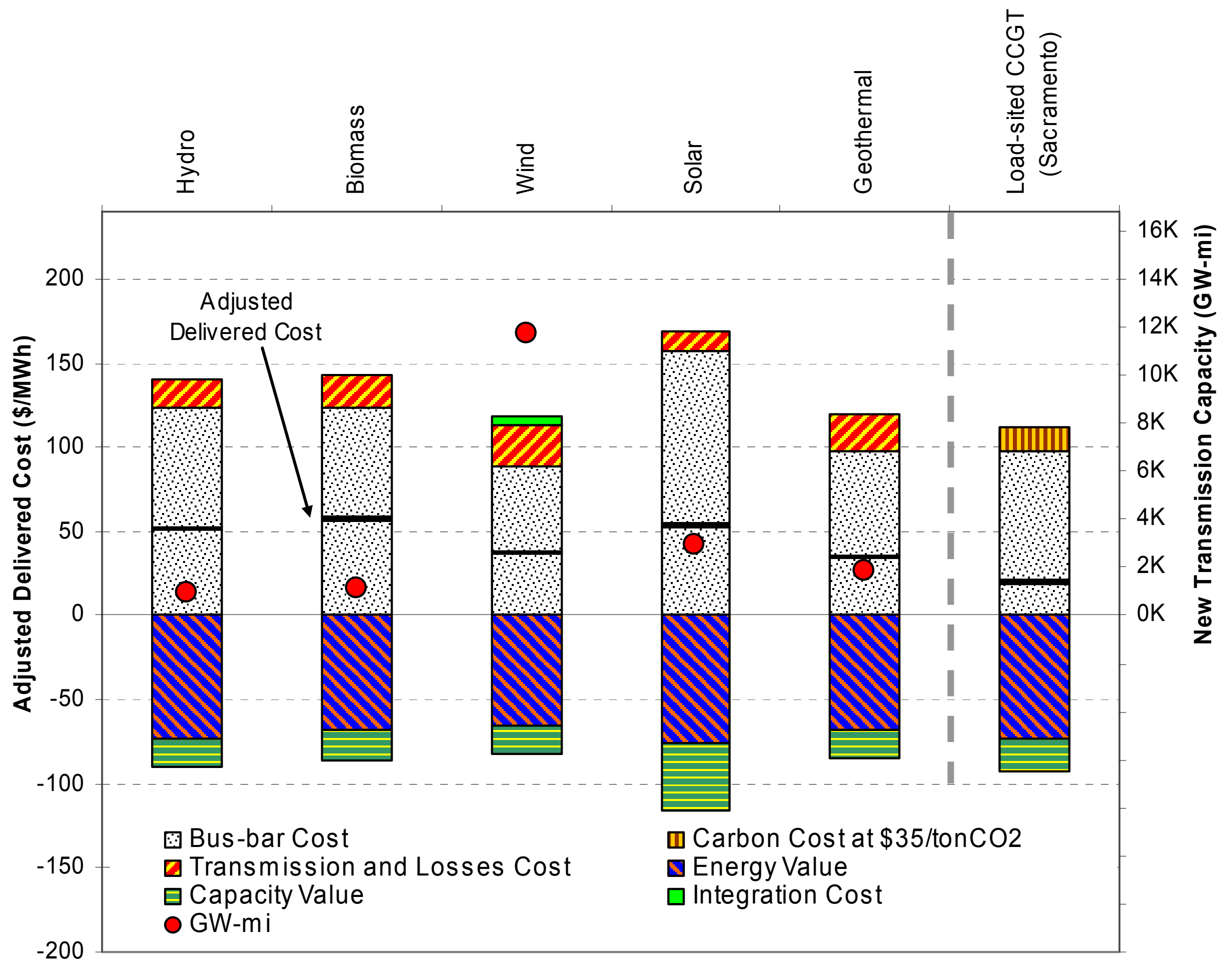
Though the total investment in transmission estimated to be required to meet a WECC-wide 33% RE target with WREZ-identified resources may be substantial, transmission and line loss costs only represent a small portion (15%) of the total average delivered cost of renewable energy supply. The bus-bar costs of renewable energy constitute the dominant portion of total delivered costs (85%). For comparison, integration costs add just 2%. For some specific resources and load zones, however, transmission costs can constitute a larger fraction of total costs, and can drive overall costs to relatively high levels. In the most extreme case, the Seattle load zone is found to procure a portion of its RE target from wind energy in Wyoming over a transmission line that is over 1000 miles long. The allocated cost of transmission in this instance is $95/MWh for a wind resource that has a bus-bar cost of just $72/MWh; as a result, transmission and line losses make up 55% of the costs to Seattle of procuring wind energy from Wyoming.[34] (In the

[34] Analysis by Denholm and Sioshansi (2009) suggests that costs can be reduced in a case similar to this with large distances between load and wind by downsizing transmission to 60% of the nameplate capacity of the wind plant and adding compressed air energy storage (CAES) with a generation capacity equivalent to about 5% of the nameplate capacity of the wind farm. While this is an option that is worth exploring further, we do not do so directly in this report. Our high utilization case, reported later, however, may indirectly illustrate the potential

next section we examine the potential reduction in costs and increase in transmission expansion if lines longer than 400 miles to wind and solar resources, such as this Wyoming to Seattle line, are replaced with 500 kV HVDC lines).

More generally, the cost of procuring renewable energy for the 33% RE target is found to be largely offset by the capacity value and TOD energy value of the procured renewable resources. Figure 10 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. For comparison, the cost and value components of a baseload CCGT are presented as well. As shown, the (unadjusted) delivered cost of solar is the highest of all of the renewable technologies, on average, but the high degree of correlation between solar generation and load in regions that select solar also leads to the highest TOD energy and capacity value; the result is a favorable adjusted delivered cost. 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. The comparatively lower bus-bar costs of wind, however, put that resource in good economic standing relative to solar despite this difference in energy and capacity value.

change in resource procurement and transmission expansion if such a strategy were used to increase transmission utilization.



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

4.4 Alternative 33% RE Scenarios with Energy Delivered to Each Load Zone

To examine the robustness of the resource mix, transmission expansion requirements, and costs for the WECC-wide 33% RE Base case, we individually change a number of key input assumptions. Here we focus on the "Competition without RECs" 33% RE scenarios, whereas in Section 4.5 we summarize the two REC cases (these latter results are included in the figures included in this section, but textual summaries of the key findings are presented in Section 4.5).

4.4.1 Impact of Alternative Scenarios on Resource Composition

As shown in Figure 11, the different 33% RE scenarios cause shifts in resource composition primarily between solar and wind. The aggregate amount of geothermal, hydropower, and biomass constitutes a relatively small proportion of the total mix, with only slight changes in this proportion relative to the Base case. Geothermal in particular is fully utilized in all 33% RE scenarios that do not allow tradable RECs. This result is likely due to the constrained nature of these resources within the WREZ resources hubs considered in the model and could be different if resource regions that are insufficient to justify a new 500 kV transmission line (i.e., non-WREZ resources) were included in our analysis. Wind and solar energy are found to compete primarily in the southwestern United States, and subtle changes in assumptions can lead to relatively significant shifts in procurement between these two resources.

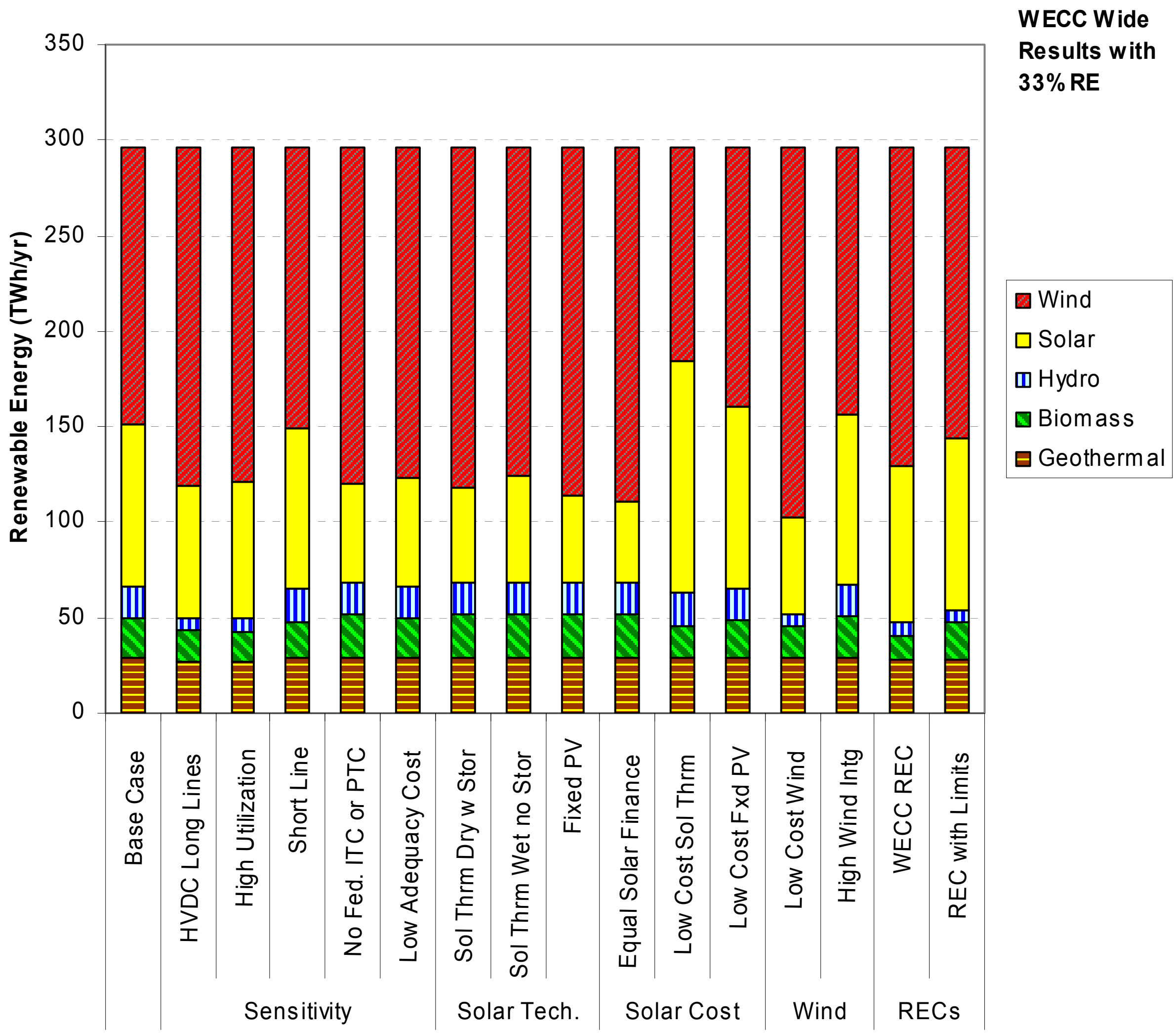


Figure 11. Resource composition in 33% renewable energy scenarios

Sensitivity Cases

The share of wind energy in the overall resource portfolio is sensitive to transmission cost assumptions. As noted earlier, even in the Base case, wind power is the most reliant on new transmission investment of the renewable sources considered in this analysis. It is therefore understandable that wind energy increases in the HVDC Long Lines case and the High Utilization case by 23% and 21%, respectively, because more-remote wind resources become less costly overall to procure in these two scenarios. The HVDC Long Lines case assumes that transmission costs (per GW-mi) are, on average, 58% less expensive for wind and solar resources that are over 400 miles from the load centers that they serve, and that transmission incurs 17% less losses than the 500 kV single-circuit transmission lines used in the Base case. Because the RE target remains fixed at 33%, an increase in the procurement of wind comes as the expense of other resources—primarily solar and a small amount of hydropower in the HVDC Long Lines and High Utilization cases. Interestingly, the Short Line case has an insignificant impact on overall resource composition relative to the Base case. This indicates that resources procured in the Base case that are farther than the maximum line length established in the Short Line case are largely replaced with resources of the same type, but closer to load zones.

The procurement of solar energy is found to decline in the Low Resource Adequacy Cost case and the No Federal ITC or PTC case because solar becomes less economically attractive relative to wind in those scenarios. In the Low Resource Adequacy Cost case, the relatively higher market value of solar compared to wind narrows somewhat as capacity becomes less valuable to the power system. More specifically, the energy-weighted average capacity value of solar declines from $40/MWh in the Base case to $26/MWh in the Low Resource Adequacy Cost case—a drop of $14/MWh. Wind energy, which has a lower average capacity value in the Base case of $17/MWh, is much less affected in the Low Resource Adequacy Cost case: the average capacity value of wind energy drops to $10/MWh—a reduction of $7/MWh. Similar reasoning explains the decrease in solar that occurs with the removal of the 30% ITC in the No Federal ITC or PTC case. Replacing the 30% investment tax credit with a 10% credit increases the energy-weighted bus-bar cost of the Base case solar technology by nearly $60/MWh. The complete loss of the ITC for wind, on the other hand, only increases the bus-bar cost of wind energy by $40/MWh. As a result, the loss of the ITC dramatically reduces procurement of solar energy.

Since the primary changes in portfolio composition are due to shifts between wind and solar resources, changes in the resource portfolios of individual load zones occur primarily in regions where some solar enters the portfolio in the Base case. In fact, sensitivity cases that reduce the amount of solar on a WECC-wide basis can cause dramatic flips in the resource choices of individual load zones. For instance, in the Base case, Tucson and Las Vegas are found to meet their 33% RE targets primarily with solar from Arizona. In the No Federal ITC or PTC case, however, wind resources in the Southwest replace these Arizona solar resources. The HVDC Long Lines and High Utilization cases can similarly cause large flips in resource composition for individual load zones. That said, nine out of 20 load zones see only negligible shifts in resource composition as a result of these sensitivity cases: eight of these load zones nearly always procure wind[35] and one load zone, San Diego, always procures solar.

Solar Technology and Cost Cases

Using the starting point cost and performance assumptions in the WREZ model, the wet cooled solar thermal technology with thermal storage is found to be the most economically attractive solar option on a WECC-wide basis; this result justified using this as the solar resource in the Base case analysis. In the alternative solar technology scenarios presented in Figure 11 we find that solar procurement declines in favor of increased wind penetration, and that the resource

[35] Wind is by far the largest resource procured across all of the sensitivity cases for nine load zones: Albuquerque, Billings, Boise, Calgary, Casper, Denver, El Paso, and Spokane

composition of Southwestern load zones is affected by the choice of solar technology. The procurement of solar by Tucson and Las Vegas, for example, is particularly sensitive to the assumption that wet cooling is available for solar thermal with storage; assuming that only dry cooling is available causes Tucson to shift to New Mexico wind and Las Vegas to shift to wind from southwestern Utah.

The relatively large amount of solar in the Base case is also found to be highly sensitive to the assumption that the debt life of solar is 25 years, while all other renewable technologies have a debt life of 15 years. The amount of solar procured to meet the 33% RE target is found to decrease by 50% in the Equivalent Solar Finance case, relative to the Base case; financing assumptions should therefore be carefully considered in more detailed analysis. Conversely, a decrease in the cost of solar technologies is, not surprisingly, found to substantially increase the share of solar while decreasing the share of wind. With a 30% reduction in the cost of wet-cooled solar thermal with storage and the ITC, solar becomes the largest contributor to meeting incremental WECC-wide RE demands; in all other cases, wind energy is the largest contributor. Eleven of the 20 load zones procure solar to meet at least some portion of their 33% RE target in the solar cost reduction cases, compared to seven load zones in the Base case (the additional load zones procuring solar include Albuquerque, El Paso, Reno, and Salt lake City). On the other hand, there are nine load zones that, under all of the cases tested, are never found to procure solar to meet their RE target.[36]

Wind Cases

Increasing wind integration costs (to \$10/MWh) relative to the Base case (\$5/MWh) is found to have only a modest effect on resource composition (wind procurement declines by just 3%). Of all load zones, Vancouver and Seattle reduce their procurement of wind the most, indicating that some non-wind resources are slightly more expensive for these load zones in the Base case but become more economically attractive when wind integration costs increase by \$5/MWh. There are a number of load zones that do not change the amount of wind that they procure, even with the doubling of wind integration costs. This is because the other components of the adjusted delivered cost, such as bus-bar cost and the energy and capacity value of wind, make wind attractive relative to other resources, irrespective of a \$5/MWh increase in integration costs. This result suggests that these load zones should focus less on quantifying the *costs* of integrating wind and more on *how* to integrate increasing quantities of wind energy.

Meanwhile, decreasing the capital cost of wind relative to all other technologies increases the procurement of wind by 34%, while decreasing the procurement of solar commensurably. Even in this case, however, Phoenix, Los Angeles, and Las Vegas each still procure over 1/3 of their renewable resources from solar energy; wind makes up the rest of these load zones' portfolios in the Low Cost Wind case. San Diego still procures entirely solar in the Low Cost Wind case.

[36] The specific load zones that are found to not procure solar in any of the solar cost reduction cases are in the northern portion of the WECC region: Billings, Boise, Calgary, Casper, Denver, Portland, Seattle, Spokane, and Vancouver.

4.4.2 Impact of Alternative Scenarios on Transmission Expansion

Sensitivity Cases

As shown in Figure 12, 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 remaining sensitivity cases result in relatively little change in transmission expansion relative to the Base 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. Converting transmission lines that access remotely-located wind and solar resources to 500 kV HVDC lines increases the economically optimal amount of total transmission capacity by nearly 50%. Whereas only 17% of the renewable energy was procured over long lines (over 400 miles) in the Base case, 33% of the renewable energy is procured over long lines in the HVDC Long Lines case. This increased transmission expansion is largely due to the Tucson load zone switching from Arizona solar to New Mexico wind, and increased procurement of Wyoming and Montana wind by Pacific Northwest load zones. The increased competition for Wyoming wind in the HVDC Long Lines case also leads Denver to increase its procurement of Colorado wind and biomass. Similar changes in procurement and transmission expansion exist in the High Utilization case. The Short Line case, on the other hand, leads to only a slight reduction in the energy-weighted average transmission distance from the Base case of 245 miles to the Short Line case of 230 miles (a reduction of 6%), and a similarly modest reduction in overall transmission expansion needs. This somewhat surprising result largely reflects the fact that, in the Base case, only a small amount of energy is procured over lines that exceed 400 miles (or 700 miles for Seattle and San Francisco); the Short Line case therefore does not impose significant new constraints.

Solar Technology and Cost Cases

The three solar technology cases each leads to a reduction of solar and an increase in wind relative to the Base case. As a result, these cases require more transmission to be built than in the Base case. The counter-intuitive increase in transmission expansion in the Low Cost Fixed-plate PV case appears to be due to load zones outside of the Southwest procuring an increased amount of distant resources that were otherwise procured by Southwest load zones in the Base case. The important conclusion from these cases is that assumptions about solar technologies and future cost reductions will affect the quantity and location of new transmission investment. These factors, therefore, warrant consideration in transmission planning efforts.

Wind Cases

A decline in wind costs relative to all other renewable technologies leads, perhaps not surprisingly, to the third largest increase in transmission expansion after the HVDC Long Lines and High Utilization cases. This increased transmission expansion is found to largely accommodate Tucson's procurement of New Mexico wind and Las Vegas's procurement of wind resources in southwestern Utah. A doubling of wind integration costs, on the other hand, is found to have a negligible impact on transmission needs, relative to the Base case.

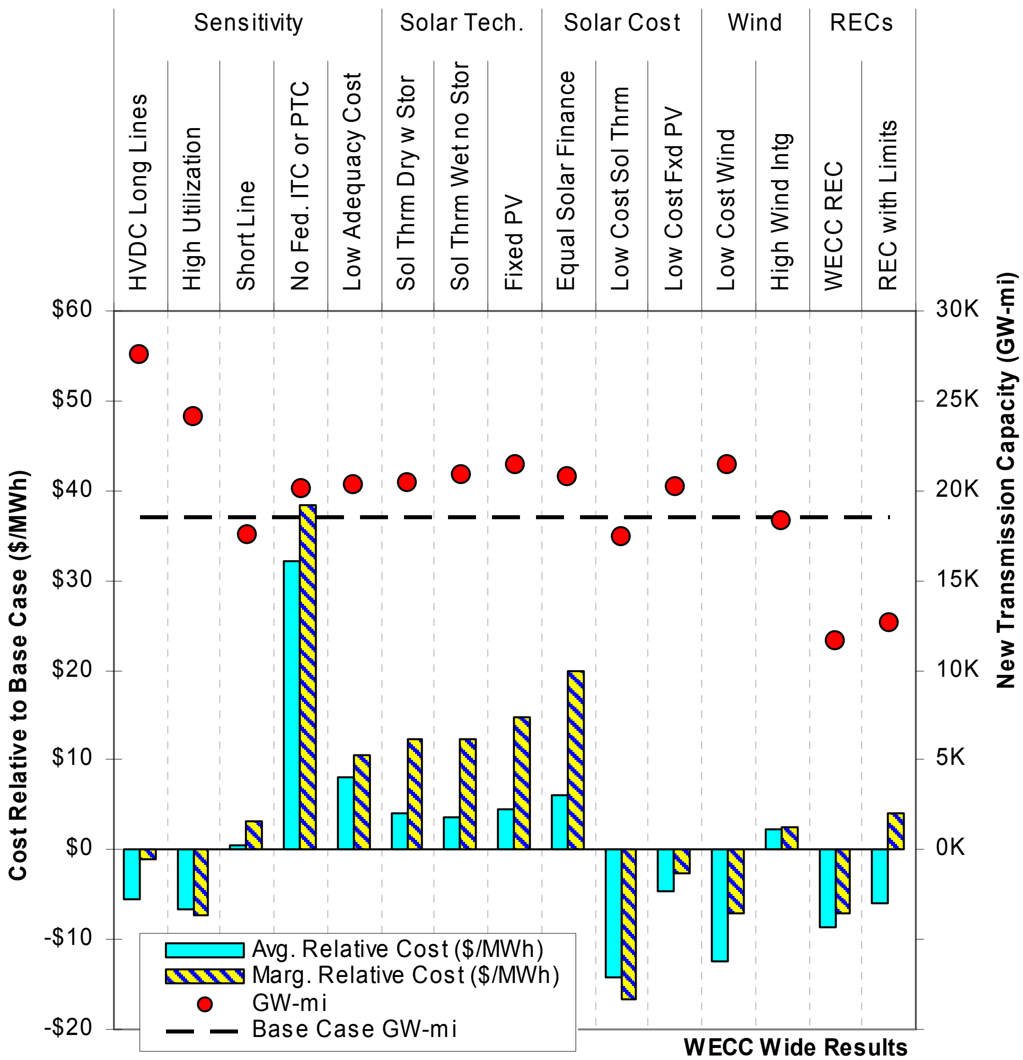


Figure 12. Cost and transmission expansion in 33% renewable energy scenarios

4.4.3 Impact of Alternative Scenarios on Cost

Sensitivity Cases

Though the HVDC Long Lines and High Utilization cases increase estimated transmission needs relative to the Base case, both of these cases also modestly reduce the average and marginal cost of renewable energy supply, relative to the Base case (Figure 12). This finding suggests that an expansion of low-cost transmission in the western U.S. may reduce the cost of meeting aggressive renewable energy targets. It deserves note, however, that these two cost reduction cases might be considered best case scenarios. In the HVDC Long Lines case, for instance, transmission costs are allocated based on each renewable resource's pro-rata subscription to the transmission line. More detailed analysis is required to develop a rational transmission plan that would fully subscribe the 3000 MW transfer capacity of these HVDC lines and account for any upgrades to the underlying AC system to accommodate the large power injections from the resulting AC/DC terminals. In the High Utilization case we assumed that the utilization of transmission lines with wind and solar could be increased to 60%, thereby reducing the cost of transmission for these resources, but more detailed analysis is required to determine the ability and costs associated with increasing transmission line utilization in this fashion. If wind curtailment is required to increase transmission line utilization, for example, then the opportunity cost of curtailing wind rather than displacing fuel used by a conventional generator would need to be accounted for. Denholm and Sioshansi (2009) outline a methodology that could be used to evaluate the tradeoffs between increased transmission utilization and increased wind curtailment.

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. The Short Line and Low Adequacy Cost cases modestly increase costs relative to the Base case.

Solar Technology and Cost Cases

The three solar technologies cases are all found to increase the expected cost of meeting the WECC-wide 33% RE target. The wet-cooled solar thermal technology without thermal storage and the fixed-plate PV technologies are both assumed to have lower capital costs than the wet-cooled solar thermal with thermal storage used in the Base case. This indicates that the WECC-wide increase in costs shown in Figure 12 associated with these cases is due to the lower capacity factors and lower TOD energy and capacity value of these technologies. The dry-cooled solar thermal plant with thermal storage has a higher capital cost, lower capacity factor, and lower TOD energy and capacity value than the solar technology assumed in the Base case, ensuring that dry cooled solar thermal is less economically attractive than wet-cooled systems, all else being equal.

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. A similar cost reduction for fixed-plate PV also significantly decreases the estimated cost of meeting the 33% target, but to a lesser degree due to the relatively higher adjusted delivered cost of fixed PV relative to wet-cooled solar thermal technology with thermal storage.

Wind Cases

The High Wind Integration case increases the cost of wind integration by $5/MWh and results in an energy-weighted average increase in costs of renewable energy across the WECC region of about $2.4/MWh. This result is intuitively plausible, because wind makes up about half of the estimated renewable energy supply in both the Base case and High Wind Integration case. Given the minor impact on overall resource portfolio composition and costs, wind integration costs in the range of $5/MWh to $10/MWh appear to have secondary importance in determining least-cost portfolios to meet aggressive renewable energy targets.

The bus-bar cost of wind energy, in contrast, is a very important consideration in determining the overall resource portfolio composition, the transmission expansion needs associated with that portfolio, and the overall supply cost of renewable energy. As shown in Figure 12, the Low Cost Wind case leads to an overall reduction in average costs of over $12/MWh.

4.5 Alternative 33% RE Scenarios with Renewable Energy Credits

The previous cases all assumed 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. This assumption 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. Further, if one of the main goals of aggressive RE targets is to reduce carbon dioxide (CO_2) emissions, it does not matter where those CO_2 emissions are reduced.

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 West already allow the use of RECs, though sometimes with restrictions, and in this section we relax the requirement that each load zone physically deliver new renewable energy to its location and instead allow for trade in RECs. 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 renewable resources it is potentially very challenging to mange penetrations in excess of 50%. Though we present both REC cases here, the REC with Limits case is likely a better reflection of the true benefits of allowing REC trade on a WECC-wide basis.

4.5.1 Resource Procurement Changes with RECs

The overall estimated composition of renewable energy procured in the WECC region does not materially change with the introduction of RECs (Figure 11). Allowing RECs tend to slightly increase the use of wind energy and reduce the use of hydropower, particularly hydropower in British Columbia. 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 13. In the top of Figure

13 we present the unconstrained results that allow load zones to procure renewable energy via physical deliveries up to their total annual energy consumption (100% RE penetration). In the bottom of Figure 13 we present the REC with Limits case in which load zones are restricted to procuring 33% of annual load from any one RE technology and 50% from the aggregate of all RE technologies. Because the market value adjustment factors do not change with RE penetration, 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.

Notwithstanding those caveats, Figure 13 demonstrates that regions that increase renewable procurement in the two REC cases 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 case (left half of x-axis). Each bubble in Figure 13 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 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 case (REC MADC). The adjusted delivered cost of the marginal RE resource in the WECC REC case is \$54/MWh and is higher in the REC with Limits case (\$66/MWh). 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 cases, where financial responsibility for meeting WECC-wide targets is more evenly spread across load zones.

The upper chart illustrates the change in renewable procurement without any technology-specific limits. The lower chart shows that restricting any load zone to procuring less than 33% of its annual energy from each renewable technology and less than 50% from all incremental renewables reduces the amount of renewables procured in the WECC REC case for a number of load zones (particularly those near high wind regions) and increases the amount in load zones that can take advantage of diverse renewable technologies. Los Angeles, for example, has a marginal adjusted delivered cost in the Base case that is similar to the marginal adjusted delivered cost in the WECC REC case, and is therefore not a large net seller of RECs in the WECC REC case. The limits on renewable procurement in the REC with Limits case, however, drive the marginal adjusted delivered cost in the REC with Limits case above the marginal adjusted delivered cost in the Base case for Los Angeles: in this instance, Los Angeles can take advantage of the diversity of solar, geothermal, and wind energy to which it has access and become a net seller of RECs. Denver, on the other hand, would be a net exporter of RECs if there were no RE procurement limits, but because wind can only provide 33% of its annual energy in the REC with Limits case, Denver stops exporting RECs and only procures sufficient wind to supply its own 33% RE target.

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.[37] 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.[38]

4.5.2 Transmission Expansion and Cost Changes with RECs

The transmission expansion needs of the two cases with RECs are substantially lower than in the Base case, and we observe changes in the location and length of that transmission (see Figure 9 and Figure 12, while Appendix C presents some of these results graphically). As a result of those shifts, the cost of meeting a WECC-wide 33% RE target with RECs is found to be $8.7/MWh lower than in the Base case, though this cost reduction advantage is reduced to $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 $9.9 billion (37%) in the WECC REC case and by $8.4 billion in the REC with Limits case, relative to the Base case. As another measure for the reduction in transmission investment needs, the energy-weighted average transmission distance in the REC with Limits case is only 150 miles, compared to the Base case average distance of 245 miles. 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 9).

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.

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[37] This result is partly due to the assumption that the only resources available to meet renewable targets are the resources included in the WREZ resource hubs. There may be resources outside of WREZ resources that can compete with RECs.

[38] Vancouver also uses RECs in part due to the lowered bus-bar costs of U.S. resources, which is driven by the assumed availability of the ITC in the United States.

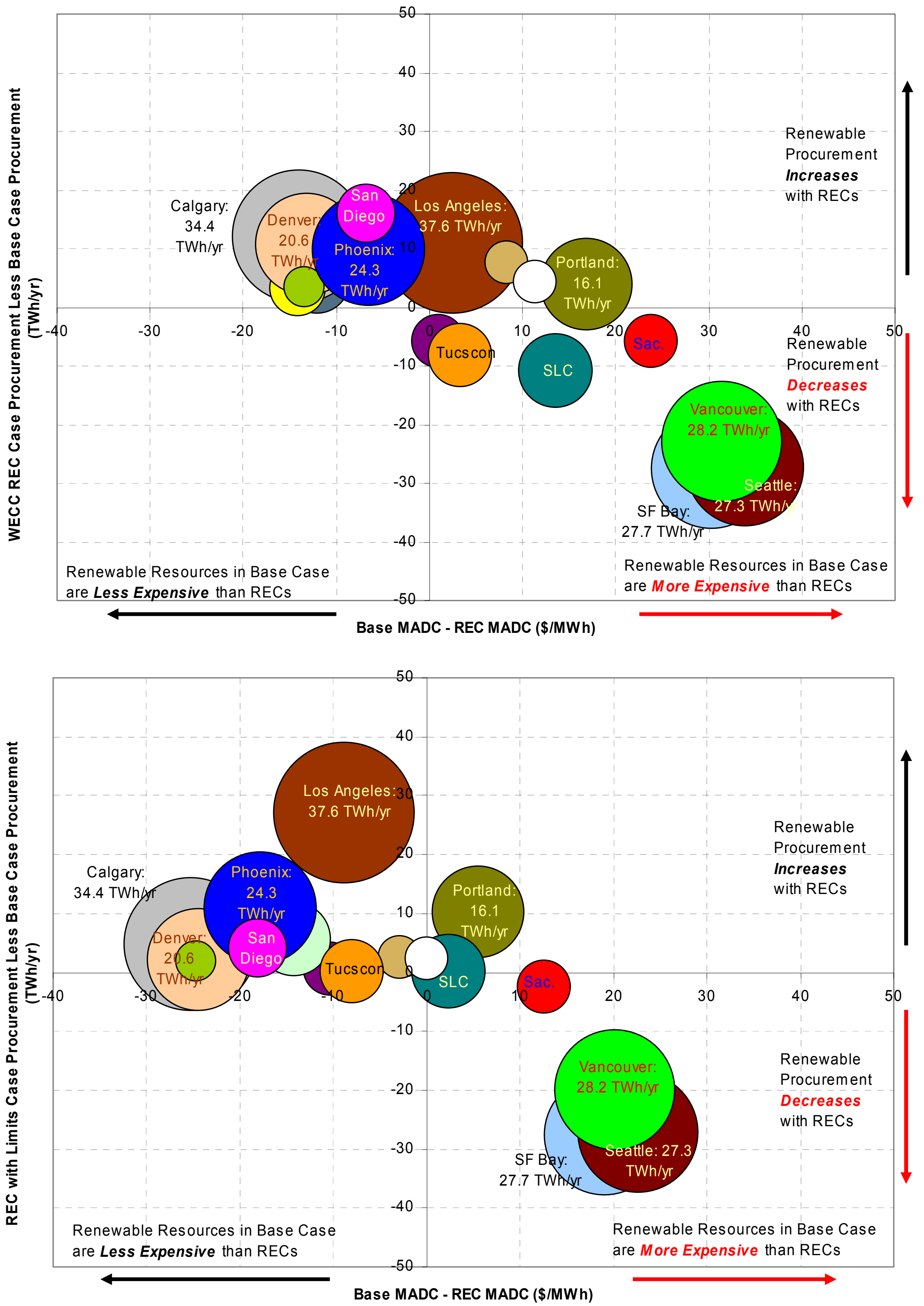

Figure 13. Change in resource procurement between the Base case and the WECC REC case (top) and the Base case and the REC with Limits case (bottom)

5. 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. The data used in the WREZ model indicates that bus-bar costs, and the drivers of bus-bar costs like federal incentives and resource quality, are important factors in determining which resources load zones should procure from to meet increased renewable energy targets. Bus-bar costs, however, are only one piece of the puzzle. Transmission costs and market value adjustment factors also play an important role in determining the relative economic attractiveness of different renewable resources. In particular, we find that the relative economic attractiveness of renewable resources with low capacity factors (e.g., wind and solar) are more sensitive to transmission distance and line voltage than are renewable resources with higher capacity factors (e.g., biomass and geothermal). We also find that the market value of solar, which is considerably higher than the other renewable resources in most instances, is largely influenced by the correlation of solar output with load and the ability of solar to contribute significantly towards resource adequacy needs. The energy and capacity value of wind is substantially lower than solar in most cases, and can vary from one pairing of load and resource to another: wind resources that produce substantial electricity during winter evenings will be less valuable to summer peaking load zones than the same wind resource will be to the winter peaking loads observed in the Northwest. On the other hand, costs associated with the short-term variability and uncertainty of variable generation, largely captured in the integration cost term, are minor compared to the other drivers of cost and value.

Using the starting point assumptions of the WREZ Peer Analysis tool, we found that a number of load zones in the WECC region might find the same WREZ renewable resource hubs economically attractive for meeting local RE targets. In a WECC-wide 33% RE target case with all renewables procured from WREZ resources hubs, however, we find that some of these highly attractive resource regions are not large enough to satisfy all possible demands. We allocated these limited resources to the load zone that has the most economic benefit from procuring the resource. In a competitive market where all load zones are simultaneously looking to satisfy high RE demands, resources would be procured by the load zone that is willing to pay the highest price to the resource developer. In reality, however, early actors that secure resources before renewable demand increases WECC-wide may be able to access resources that would otherwise become too expensive with increased competition. The resources that any one load zone will seek to procure will therefore depend on their ability to secure resources before others and on the timing of different levels of renewable targets for different load zones. We have bracketed the potential outcomes of this process by ranking resources for each load zone acting in isolation (the “individual best” case) and by presenting results using the competitive allocation mechanism. It is again 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 based on the analysis presented here:

- *Increasing renewable energy demands increase costs, as less economically attractive resources are required to meet higher targets:* The largest source of additional renewable energy when increasing renewable energy demand from 12% to 25% on a WECC-wide basis is found to be 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 energy targets increase from 25% to 33% WECC-wide. 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 energy is 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 presented in this paper. Solar energy is the second largest resource, providing 14-41% of the total energy depending on the scenario in question. Wind energy was consistently found to be the most attractive resource choice in a number of load zones in the Northwest, no matter what changes were made to key assumptions.

- *Hydropower, biomass, and geothermal contributions do not change significantly with increasing renewable demand or changes to key assumptions:* Across all sensitivities to the WECC-wide 33% RE case, the combined contribution of hydropower, biomass, and geothermal to meeting the renewable targets was in a narrow range of 16-23%. Similarly, as renewable demand increases by 270% from the 12% renewable energy case to the 33% case, the combined contribution of hydropower, biomass, and geothermal increases by only 78%. A primary reason for the limited change in procurement from these resources is their limited quantities in the WREZ resource database. The Base case 33% renewable energy 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 resources, respectively. As an extreme example, the entire geothermal resource included in the WREZ database is fully utilized in a number of 33% RE scenarios; as a result, this resource is being constrained not on economic terms, but instead based on availability in WREZ resource hubs.

- *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 wind and solar resources. More wind is 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 in determining the amount of wind that is procured. More solar energy 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 costs of meeting renewable energy targets within WECC are heterogeneous without RECs:* Since resources of differing capital cost, quality, location, and market value are procured by different load zones to meet their individual renewable energy targets, the cost, both average and marginal, of renewable energy differs across load zones. 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.

- *Transmission investment costs are substantial, but are only a fraction of the costs required to meet a 33% renewable energy target:* 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. The primary technology driving this transmission expansion is wind. 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.

- *Long transmission lines can be economically justified in particular cases, but the majority of transmission lines are found to be relatively short:* 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. 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, 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.

- *Transmission expansion needs and overall WECC-wide costs can be reduced through the use of Renewable Energy Credits:* The most dramatic decrease in transmission expansion needs while still meeting a 33% renewable energy target WECC-wide was through the use of RECs. 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.

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Appendix A. Change in Market Value Adjustment Factors with Increased Penetration

Our analysis assumed that all market value adjustment factors were constant across most scenarios, and did not change with increasing levels of renewable energy penetration. Though clearly a simplifying assumption, and further research should explore this assumption in greater detail, we do not believe that this assumption is unreasonable in a screening-level analysis such as that which is reported here.

Integration costs, for example, are expected to rise with increased renewable energy penetration, but studies do not reveal steep changes in wind integration costs at penetration levels up to and above 20% on an energy basis, assuming that various measures are taken to manage the increased variability and uncertainty in the power system. Individual integration studies show an increase in cost of only about $4/MWh with increasing wind penetration from low levels up to as high as 30% on a capacity basis (Wiser and Bolinger, 2009). Moreover, recent wide-area integration studies show that large areas can achieve 20% or even 30% wind energy penetration levels with integration costs that average roughly $5/MWh, equivalent to the base case assumption used in our analysis presented earlier (EnerNex Corp., 2010).

The capacity credit for solar and wind is expected to decline with increasing penetration (Hoff et al., 2008; Asano et al.,1996; Hirst and Hild, 2004; Holttinen et al., 2009). This decline in capacity value, however, can be somewhat offset by diversity in wind speeds from one region to the next (Milligan and Factor, 2000; Stoft, 2008, EnerNex Corp., 2010). Geographic dispersion can mitigate the variability of solar as well, though the decline in capacity value with increased penetration of solar without storage cannot be as readily mitigated through geographic smoothing. Specifically, with increased penetration of solar without storage, the marginal capacity credit will at some level be driven to zero as the peak net load shifts to night time hours. On the other hand, thermal storage, which is assumed to be included with the solar technology used in the Base case, offers a low-cost, highly-efficiency mechanism for solar thermal plants to arrest the decline in capacity value with increasing penetration. Thermal storage allows a solar thermal plant to shift production to periods when generation is most scarce relative to demand, and the capacity value of such a plant is unlikely to change dramatically with penetration. The solar technology cases that do not employ thermal storage, however, may overstate the capacity value of solar at high penetration levels, and may therefore estimate a greater reliance on solar energy without thermal storage than is economically justified.

Finally, the TOD energy value of renewable resources will also decrease with increased penetration. Preliminary results from the Western Wind and Solar Integration Study, however, indicate that the decline in the energy value of wind and solar will not amount to more than about $8/MWh (10% of the total energy value) when the WestConnect footprint[39] is using wind to provide 30% of its energy and solar to provide 5% of its energy and the rest of the WECC region is using wind to meet 20% and solar to meet 3% of its energy in 2017.[40] Moreover, this

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[39] WestConnect includes utilities in Nevada, Arizona, New Mexico, Colorado, and Wyoming.
[40] Preliminary results from the study are available at: http://wind.nrel.gov/public/WWIS/stakeholder%20meetings/7-30-09/GE%20-%20Operational%20Impacts%201.pdf, slide 17.

estimated decline in energy value does not account for the rebalancing in the mix of conventional generation that is expected to occur in the long run with the addition of wind or solar generation (Kahn, 1979; Lamont, 2008; Miera et al., 2008). Rebalancing the fossil generation mix to minimize system-wide costs will help arrest the decline in the long-run energy value of wind and solar relative to the decline observed when wind and solar are simply added to a constant mix of conventional generation.

As a result of these considerations, it seems unlikely that accommodating any change in market value adjustments with increased renewable energy penetration would have a significant impact on the screening-level results presented in the body of this paper.

Appendix B. Mechanics of the Competitive Allocation Mechanism

The WA hydrower resource is found to be an attractive resource for all but one load zone (El Paso) in meeting a 33% RE target. The Base case results allocate the limited Washington resource to the Seattle load zone. We can explain this result by examining the net cost of Seattle procuring its next cheapest resource to meet its 33% RE demand and the net benefit of other competing load zones being able to avoid procuring their marginal resource in the competitive allocation in favor of the Washington hydropower resource. In all cases the net impact of the Washington hydro resource in a load zone's portfolio is the difference between the adjusted delivered cost of the marginal resource and the adjusted delivered cost of the Washington hydro resource to that load zone. As shown in Figure 14, Seattle does not have the lowest adjusted delivered cost for the Washington hydro resource, but the difference between the adjusted delivered cost of the Washington hydro resource to Seattle and Seattle's marginal resource in the Base case is the greatest. Therefore, Seattle has the most economic benefit to gain from adding Washington hydro to its resource portfolio, and conversely the cost of meeting the RE target in Seattle will increase the most if Seattle does not obtain the resource.

Other nearby load centers, including Vancouver and Portland, will have nearly the same economic gain by procuring this resource. These results suggest that many load zones could gain significant economic benefit by procuring this resource early, to lock in prices before other load zones begin to compete for it. Denver, on the opposite extreme, is nearly indifferent between obtaining Washington hydro and its next marginal resource in the base case. Denver, therefore, has little to gain by being an early actor and securing this resource at its cost. The small difference in the net benefit of the Washington hydro resource among multiple load zones further suggests that additional research is warranted into the viability of meeting future RE requirements with the resource, the quantity of the resource, and the costs and benefits of acquiring the resource.

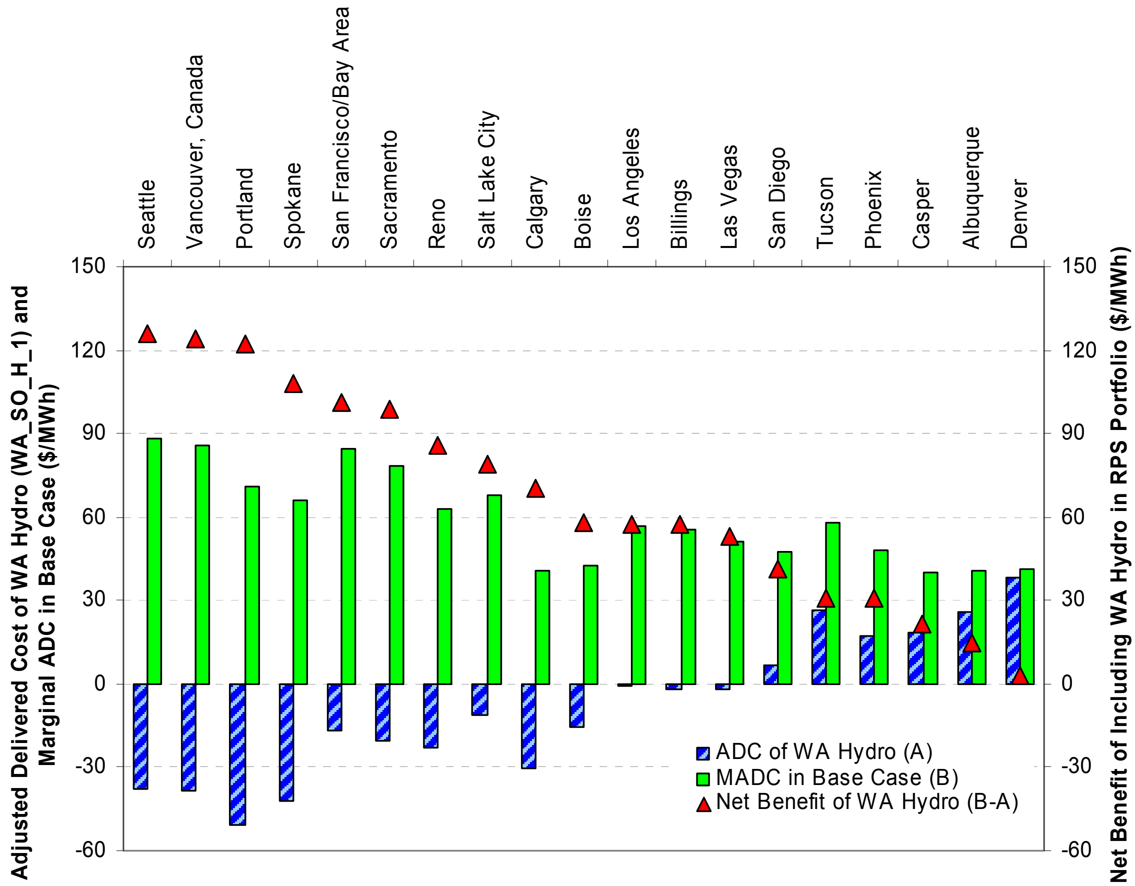
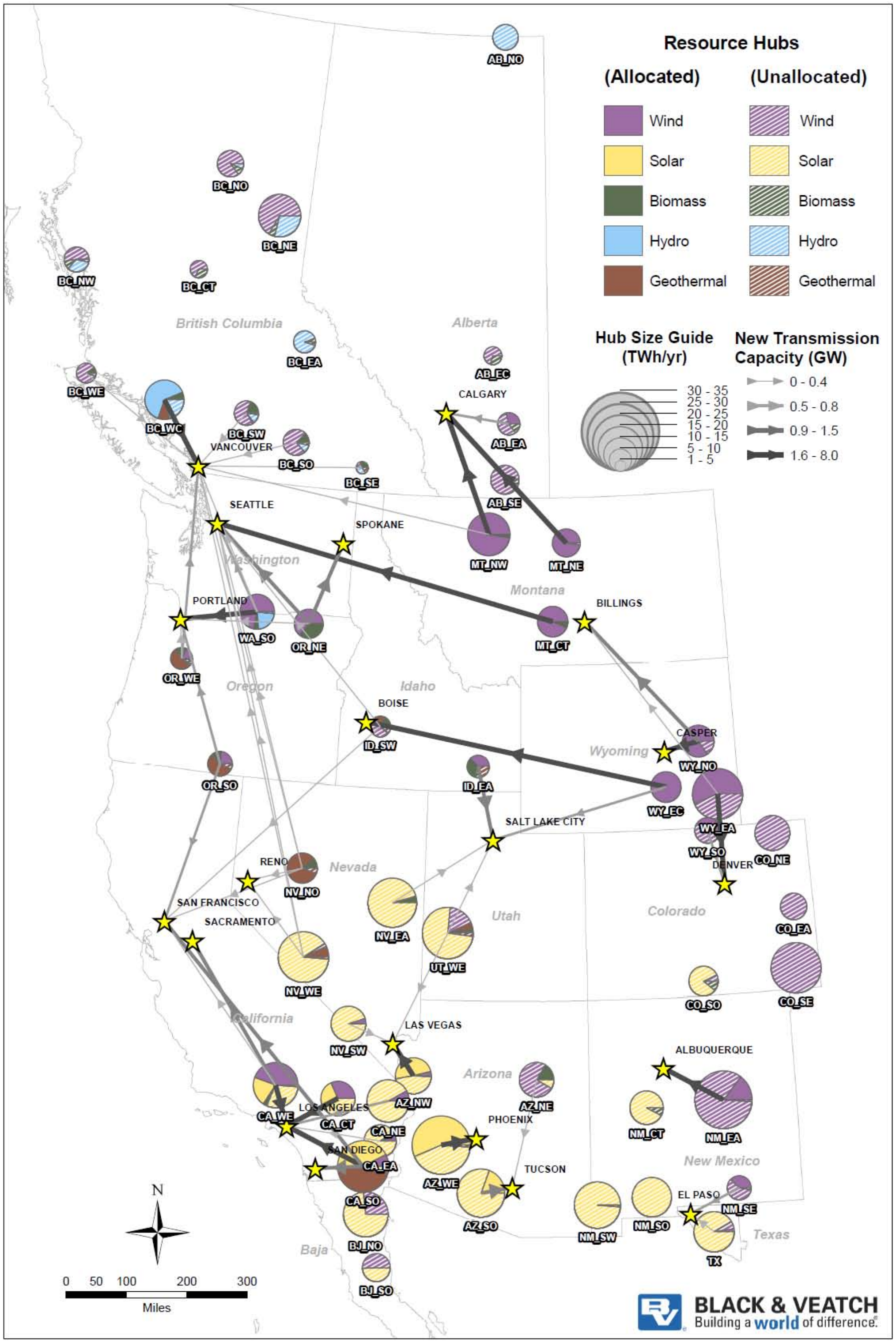


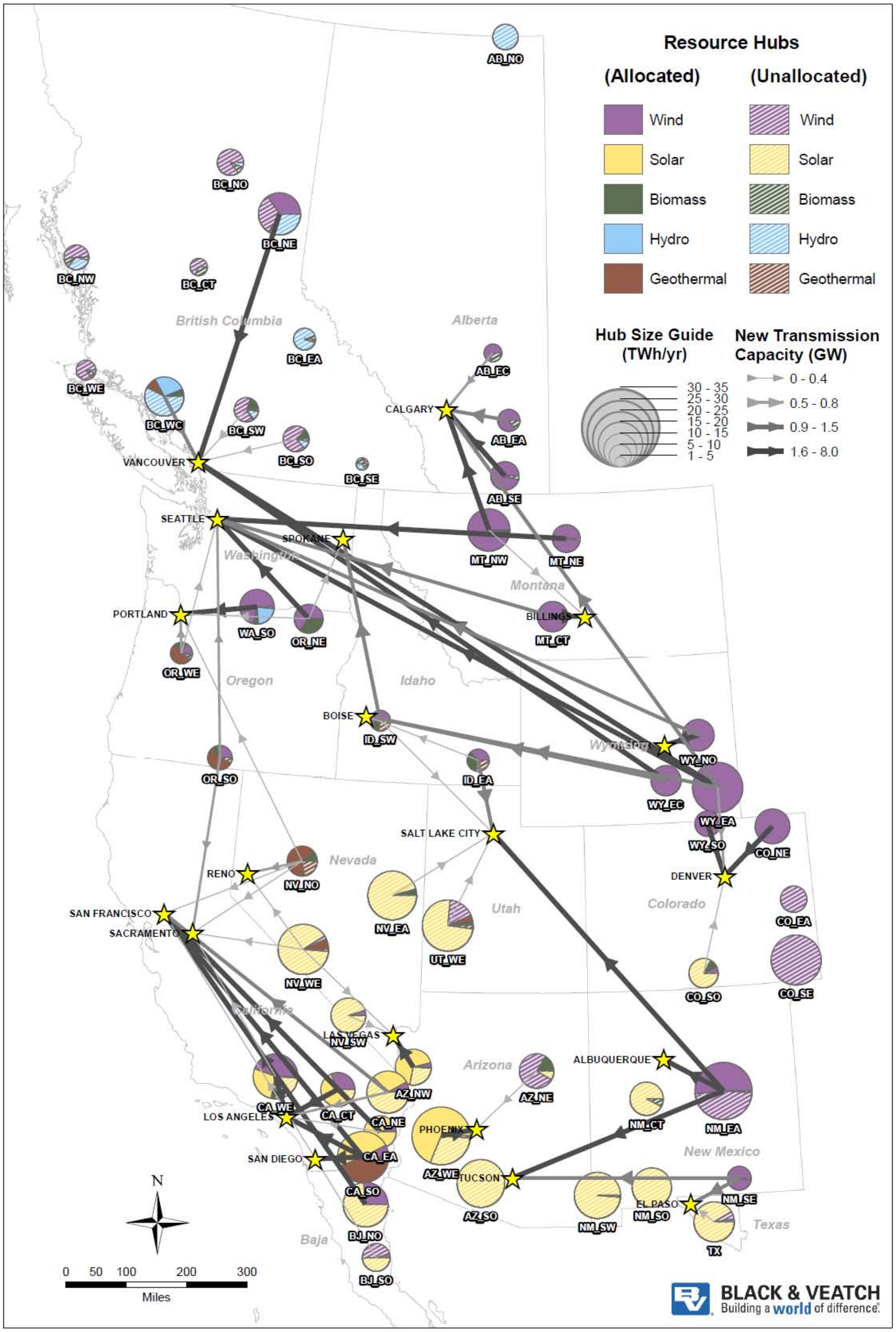
Figure 14. The adjusted delivered cost of Washington (WA) hydropower is lower than the marginal adjusted delivered cost from the Base case allocation for 19 of the 20 load zones in the WECC region. The net benefit of procuring WA hydro is the difference between the cost of the marginal resource that would be acquired otherwise (MADC in Base case) and the adjusted delivered cost of WA hydro to each load zone (ADC of WA hydro). The net benefit is greatest for Seattle, which is the load zone that is assumed to procure the hydro resource in the Base case under the competitive allocation mechanism.

Appendix C. Maps of Transmission and Resource Selection in Sensitivity Cases



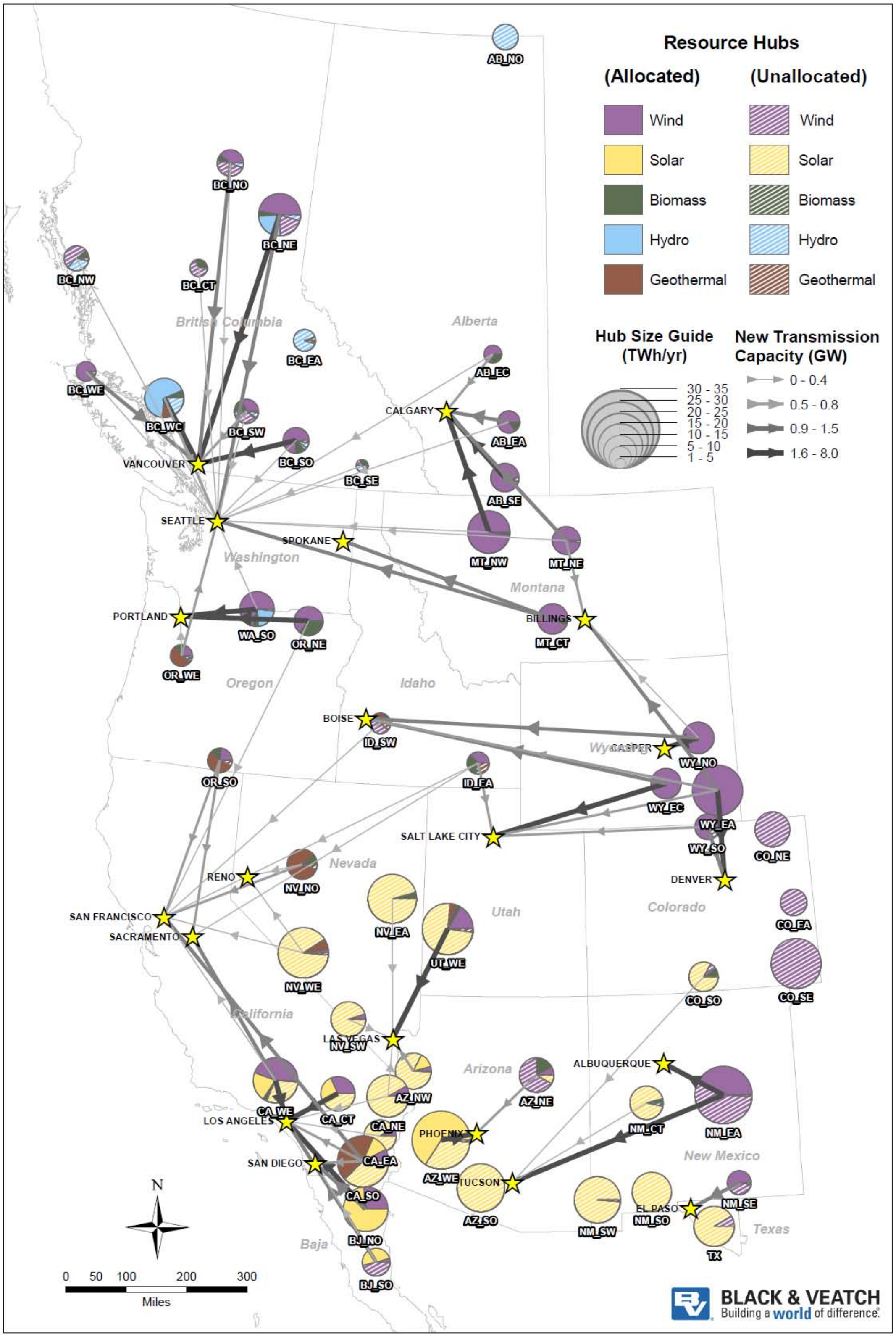
Map created 11/03/2009 by Sally Maki and Josh Finn

Figure 15. Transmission and resource selection in the 25% RE WECC-wide case



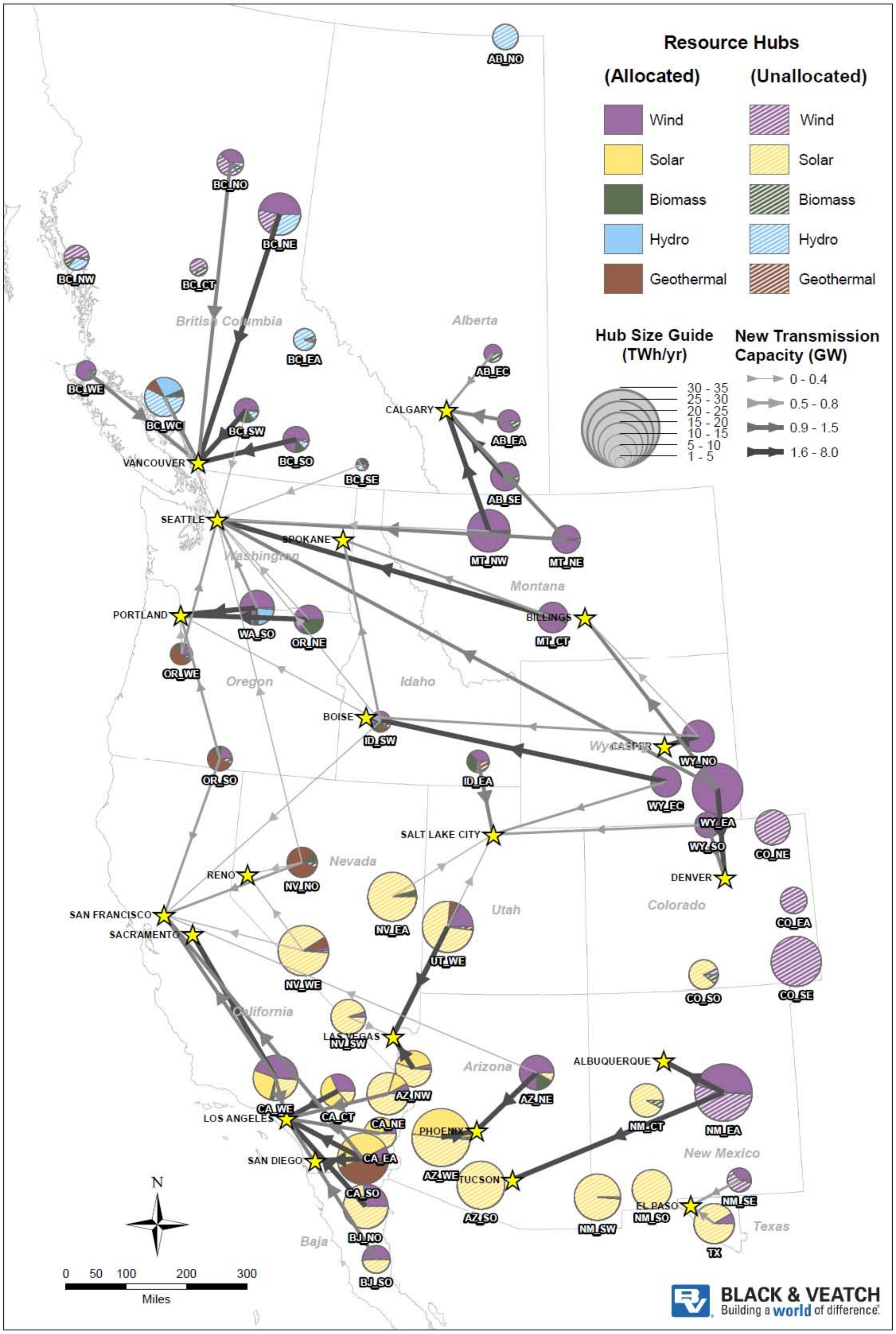
Map created 11/03/2009 by Sally Maki and Josh Finn

Figure 16. Transmission and resource selection to meet 33% RE WECC-wide in the HVDC Long Lines case



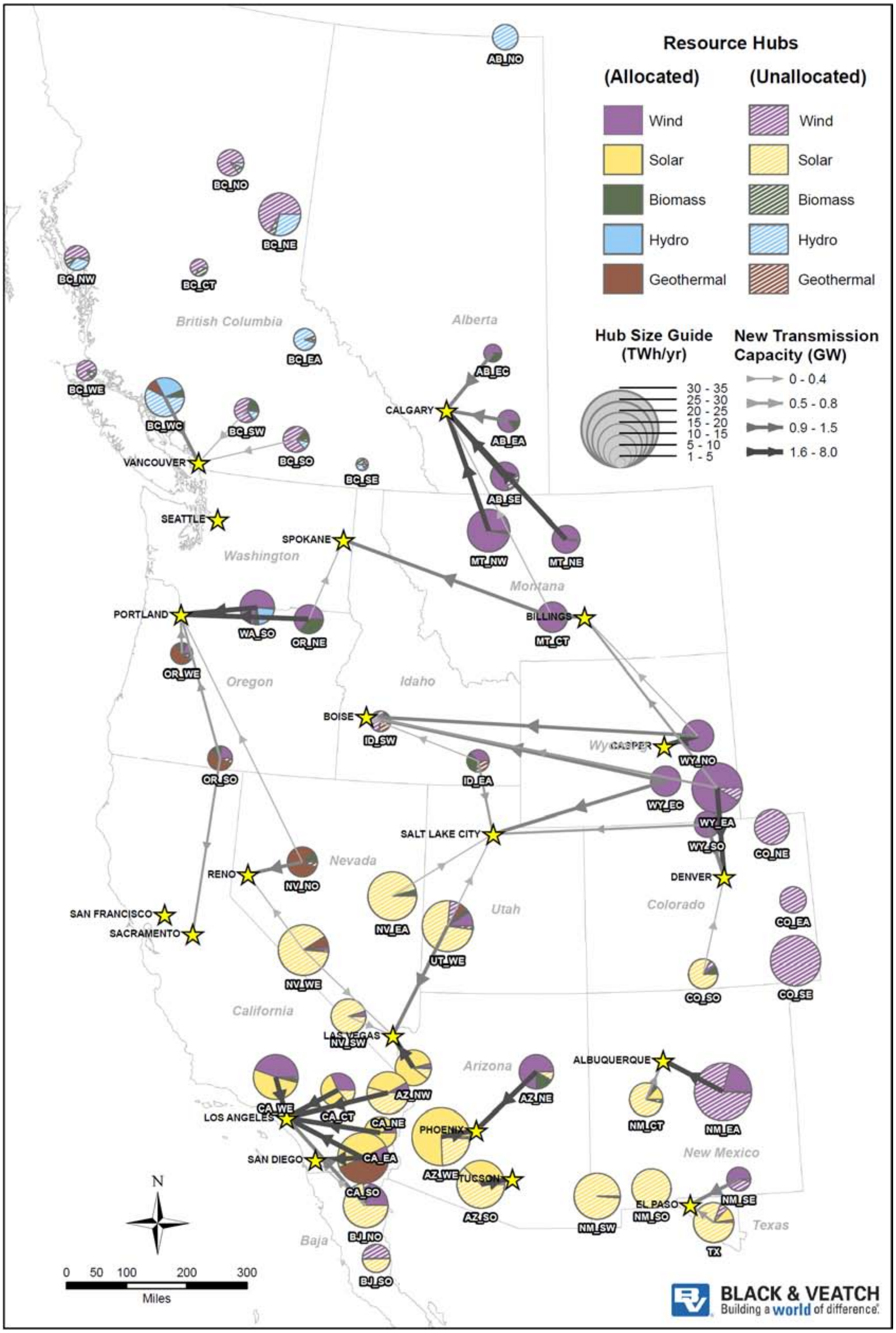
Map created 11/03/2009 by Sally Maki and Josh Finn

Figure 17. Transmission and resource selection to meet 33% RE WECC-wide in the No Federal ITC or PTC case



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

Figure 18. Transmission and resource selection to meet 33% RE WECC-wide in the Low Wind Cost case



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

Figure 19. Transmission and resource selection for 33% RE WECC-wide in REC with Limits case.

Appendix D. Detailed Base Case Results for 33% Renewable Energy WECC-wide

Table 8. Detailed Base case results for each load zone in the WREZ model

Load Zone	Resource Name	Transmission Distance (mi)	Adjusted Delivered Cost ($/MWh)	Nameplate Capacity (MW)	Annual Energy (TWh/yr)	Cummulative Energy (TWh/yr)
Albuquerque	NM_EA_W_3	86	40.8	2,243	6.2	6.2
Billings	WY_NO_W_2	307	45.8	60	0.2	0.2
	WY_EA_W_2	391	49.1	732	2.6	2.8
	WY_NO_W_3	307	49.3	975	3.1	5.8
Boise	WY_EC_W_2	229	18.1	1,406	4.9	4.9
	WY_EC_W_3	229	19.3	1,093	3.5	8.4
Calgary	MT_NW_W_2	233	4.7	1,451	5.0	5.0
	MT_NW_W_3	233	4.7	3,745	11.9	16.9
	MT_NE_W_3	391	26.2	1,536	4.9	21.8
	AB_EA_W_5	108	33.2	1,319	4.0	25.8
	AB_EC_W_5	160	36.9	700	2.1	28.0
	AB_SE_W_6	143	40.4	2,111	6.5	34.4
Casper	WY_NO_W_3	40	34.2	2,027	6.3	6.3
Denver	WY_EA_W_2	173	34.9	1,774	6.3	6.3
	WY_SO_W_3	105	37.0	1,241	3.7	10.0
	WY_EA_W_3	173	38.3	3,346	10.6	20.6
El Paso	TX_W_3	0	39.5	128	0.4	0.4
	NM_SE_W_3	110	40.9	1,035	2.9	3.3
Las Vegas	AZ_NW_W_4	41	42.1	207	0.5	0.5
	NV_SW_W_3	104	46.3	56	0.1	0.7
	NV_SW_W_4	104	48.1	177	0.4	1.1
	AZ_NW_S_DNI7	41	48.7	496	1.7	2.8
	AZ_NW_S_DNI6	41	51.4	2,259	7.6	10.4
Los Angeles	CA_WE_W_3	66	24.7	862	2.4	2.4
	CA_WE_W_4	66	27.2	290	0.7	3.1
	CA_CT_W_3	104	40.8	495	1.3	4.4
	CA_CT_W_4	104	42.6	916	2.3	6.7
	CA_NE_W_3	155	43.2	89	0.2	6.9
	CA_SO_W_3	176	44.0	463	1.2	8.1
	CA_NE_W_4	155	45.5	476	1.2	9.3
	CA_CT_S_DNI6	104	47.4	866	3.0	12.3
	CA_SO_S_DNI7	176	47.8	50	0.2	12.5
	CA_SO_W_4	176	47.8	250	0.6	13.1
	CA_EA_S_DNI7	184	48.7	106	0.4	13.5
	CA_SO_S_DNI6	176	48.7	282	1.0	14.5
	CA_EA_W_3	184	49.2	76	0.2	14.6
	CA_EA_W_4	184	50.6	161	0.4	15.0
	CA_SO_S_DNI5	176	50.6	1,160	4.1	19.1
	CA_NE_S_DNI7	155	51.0	600	2.1	21.2
	CA_EA_S_DNI5	184	51.5	1,120	3.9	25.1
	CA_CT_S_DNI7	104	51.9	910	3.1	28.2
	CA_EA_S_DNI6	184	53.2	1,455	5.1	33.3
	CA_NE_S_DNI5	155	54.6	1,272	4.3	37.6
Phoenix	AZ_WE_S_DNI7	54	47.0	1,652	5.7	5.7
	AZ_WE_S_DNI6	54	47.8	5,389	18.6	24.3
Portland	OR_WE_W_3	0	8.5	301	0.8	0.8
	WA_SO_W_3	111	24.0	1,312	3.4	4.2
	WA_SO_W_4	111	25.0	1,950	4.8	9.0
	OR_NE_W_3	220	36.0	1,277	3.3	12.4
	OR_SO_W_3	249	37.5	184	0.5	12.9
	OR_NE_W_4	220	37.7	56	0.1	13.0
	OR_SO_W_4	249	41.3	337	0.8	13.8
	ID_SW_W_4	462	70.0	917	2.3	16.1
Reno	NV_NO_G_4a	0	25.0	148	1.0	1.0
	NV_NO_B_4	0	32.2	128	1.0	2.0
	NV_EA_B_4	256	35.4	41	0.3	2.3
	NV_WE_G_4	148	38.1	116	0.8	3.1
	NV_NO_G_5	0	46.6	92	0.6	3.7

Table 8. Detailed Base case results for each load zone in the WREZ model (cont.)

Load Zone	Resource Name	Transmission Distance (mi)	Adjusted Delivered Cost ($/MWh)	Nameplate Capacity (MW)	Annual Energy (TWh/yr)	Cummulative Energy (TWh/yr)
Sacramento	CA_WE_W_2	283	38.2	198	0.7	0.7
	CA_WE_W_3	283	46.0	1,736	4.8	5.5
	CA_WE_S_DNI5	283	73.3	120	0.4	5.9
Salt Lake City	UT_WE_G_3	241	29.0	90	0.6	0.6
	UT_WE_B_4	241	38.3	87	0.6	1.3
	NV_EA_B_4	243	40.6	92	0.7	2.0
	ID_EA_B_4	155	41.6	211	1.6	3.5
	WY_EC_W_2	386	43.8	96	0.3	3.9
	UT_WE_G_4	241	46.0	65	0.5	4.3
	ID_EA_W_3	155	49.9	126	0.3	4.7
	ID_EA_W_4	155	52.5	591	1.5	6.1
	WY_SO_W_2	528	58.0	699	2.4	8.5
	UT_WE_W_3	241	65.0	123	0.3	8.9
	NM_CT_B_4	559	67.4	60	0.4	9.3
	UT_WE_W_4	241	67.9	641	1.6	10.9
San Diego	CA_SO_S_DNI5	87	41.3	1,913	6.7	6.7
San Francisco/Bay Area	OR_SO_G_3a	356	23.9	384	2.7	2.7
	CA_SO_G_4	582	34.8	1,170	9.2	11.9
	OR_SO_G_4	356	36.4	64	0.4	12.4
	CA_SO_G_3	582	36.5	232	1.6	14.0
	CA_WE_B_4	340	36.7	74	0.6	14.5
	OR_SO_B_4	356	40.0	118	0.9	15.4
	NV_NO_B_4	573	54.1	0	0.0	15.4
	ID_SW_B_4	684	60.7	98	0.7	16.2
	AZ_NE_B_4	882	64.9	257	1.9	18.1
	CA_WE_S_DNI7	340	71.1	1,219	4.1	22.2
	CA_WE_S_DNI6	340	79.0	1,325	4.3	26.4
	CA_WE_S_DNI5	340	79.7	386	1.2	27.7
Seattle	WA_SO_H_1	320	-37.6	544	2.5	2.5
	NV_NO_G_3b	675	31.9	268	2.0	4.6
	OR_WE_B_4	209	41.2	102	0.8	5.3
	WA_SO_B_4	320	41.3	75	0.6	5.9
	MT_CT_W_2	617	43.4	509	1.7	7.6
	NV_WE_G_3	823	44.1	132	0.9	8.6
	MT_CT_W_3	617	46.1	1,392	4.5	13.0
	OR_NE_B_4	422	46.5	388	2.9	15.9
	NV_NO_G_4	675	53.2	200	1.4	17.3
	MT_NE_W_3	816	74.0	760	2.4	19.7
	MT_CT_B_5	617	74.0	77	0.6	20.3
	NV_NO_G_5a	675	74.9	200	1.4	21.7
	ID_SW_G_5	664	79.2	90	0.6	22.3
	WY_EA_W_2	1061	82.0	1,404	5.0	27.3
Spokane	MT_CT_W_3	395	23.5	629	2.0	2.0
	OR_NE_W_4	200	32.2	716	1.8	3.8
Tucson	AZ_SO_S_DNI6	0	57.7	2,456	8.2	8.2
Vancouver, Canada	OR_WE_G_3	309	1.1	315	2.5	2.5
	BC_WC_G_3	100	17.2	180	1.4	3.9
	BC_WC_H_5	100	34.1	907	3.9	7.8
	NV_NO_G_3a	775	35.5	109	0.8	8.6
	MT_NW_B_4	795	58.8	60	0.4	9.1
	BC_SW_B_4	140	60.4	150	1.1	10.2
	BC_WC_B_5	100	62.7	127	0.9	11.1
	BC_SO_B_4	133	65.1	109	0.8	11.9
	BC_SE_B_4	312	72.0	60	0.4	12.4
	BC_WE_B_5	237	77.2	53	0.4	12.8
	BC_WC_H_7	100	77.3	1,365	6.1	18.8
	BC_WE_W_6	237	77.6	200	0.6	19.4
	BC_NE_B_4	565	79.8	91	0.7	20.1
	BC_CT_B_4	440	79.8	122	0.9	21.0
	BC_NO_B_4	491	80.5	78	0.6	21.5
	BC_NE_H_5	565	80.5	900	4.2	25.7
	BC_SW_W_6	140	80.8	214	0.6	26.3
	BC_SO_W_7	133	83.9	359	0.9	27.2
	AB_EC_B_4	723	85.6	122	0.9	28.1
	BC_WE_W_7	237	85.8	83	0.2	28.3

Appendix E. Summary of Non-WREZ Resources Not Considered in Analysis

Over 2,300 GW of non-WREZ resources were identified by Pletka and Finn (2009). Of the non-WREZ resource total, solar is the largest proportion with over 1,170 GW. Within the non-WREZ solar resource, 420 GW is solar thermal and 750 GW is PV. Of the solar thermal resource nearly 300 GW includes regions with between 4.5 and 6.5 kWh/m^2/day of direct normal insolation (DNI); the remaining non-WREZ solar thermal resource exceeds 6.5 kWh/m^2/day. The PV resource was not "binned" by resource class. Wind is the second largest non-WREZ resource, with over 590 GW of identified resource potential. Of the non-WREZ wind, over 350 GW is Class 3 wind resources and nearly 100 GW is Class 4. The remaining 18 GW is Class 5 or above. Geothermal makes up another 550 GW, but the majority of the non-WREZ geothermal is enhanced geothermal systems (EGS) technology, which is likely 10 years or more from significant utility-scale commercial deployment. Only 32 GW of the non WREZ-geothermal are considered "undiscovered conventional geothermal resources." The remaining 23 GW of non-WREZ renewable resource potential consists of biomass and hydropower resources. The technology and location of the non-WREZ resources identified by Pletka and Finn (2009) is shown in Table 9.

Table 9. Summary of non-WREZ resources not used in analysis

Source: Pletka and Finn (2009) Table 5.1

State or Province		Non-WREZ Renewable Resources (GW)					
		Geothermal	Biomass	Hydro	Wind	Solar PV	Solar Thermal
AB	Alberta	0.5	0.2	0.1	120.0	25.5	1.1
AZ	Arizona	55.7	-	0.1	2.3	87.0	41.9
BC	British Columbia	5.3	0.9	9.7	3.8	21.0	-
BJ	Baja, Mexico	-	-	-	6.2	18.0	7.5
CA	California	59.4	0.7	2.3	7.3	29.4	54.6
CO	Colorado	53.7	0.2	0.4	58.6	47.1	60.6
ID	Idaho	69.8	0.2	1.2	6.1	25.8	24.8
MT	Montana	17.7	0.2	0.6	196.0	123.1	38.2
NM	New Mexico	57.2	0.0	0.1	65.9	126.2	49.1
NV	Nevada	107.2	-	0.0	4.1	41.2	57.3
OR	Oregon	64.3	0.2	2.0	9.9	48.7	19.1
TX	Texas	-	-	-	0.4	12.0	0.9
UT	Utah	48.7	0.2	0.5	2.2	34.0	29.4
WA	Washington	6.8	0.3	3.0	3.9	30.6	5.2
WY	Wyoming	3.2	0.0	0.5	107.8	84.0	27.4
Total		549.4	3.1	20.4	594.4	753.4	416.9