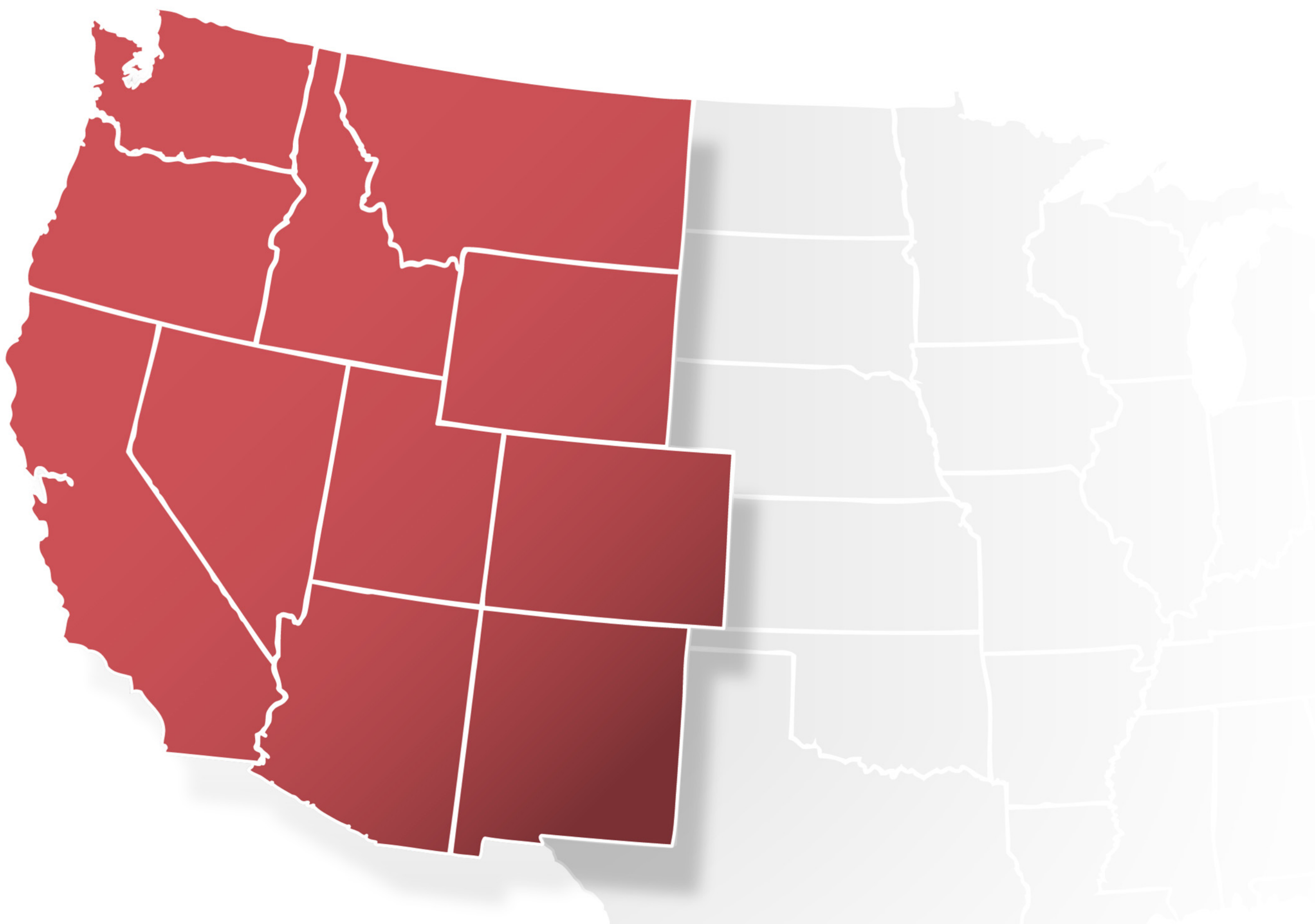
Beyond Renewable Portfolio Standards

An Assessment of Regional Supply and Demand Conditions Affecting the Future of Renewable Energy in the West



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NATIONAL RENEWABLE ENERGY LABORATORY

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Executive Summary

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The genesis of this report was a 2010 conference in Tempe, Arizona, titled “Cooperation Among States in the Western Interconnection on Electric Resource Planning and Priorities.” The conference was funded with grant from the U.S. Department of Energy (DOE) to the Western Governors’ Association (WGA) and was organized by regulatory commissioners from five southwest states: Kris Mayes, then chair of the Arizona Corporation Commission; Jim Tarpey, commissioner with the Colorado Public Utilities Commission; Rebecca Wagner, commissioner with the Nevada Public Utilities Commission; Dian Gruenich, then commissioner with the California Public Utilities Commission; and Jason Marks, then commissioner with the New Mexico Public Regulation Commission. This report expands an analytical framework presented at that conference by the National Renewable Energy Laboratory (NREL), based on recently completed work for the Western Renewable Energy Zone Initiative. The authors are grateful to these commissioners for their early encouragement.

The authors would especially like to thank Doug Larson, Tom Carr, Steve Ellenbecker, Jennifer Gardner, and Victoria Ravenscroft of the Western Interstate Energy Board (WIEB). Regional planning for transmission and renewable energy in the Western Interconnection has advanced tremendously since the 2010 Tempe conference, and WIEB staff have been at the forefront of these activities. The guidance they provided for this report was invaluable in keeping the analysis relevant.

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List of Acronyms

ACC	Arizona Corporation Commission
ACEEE	America Council for an Energy-Efficient Economy
APS	Arizona Public Service Company
BA	balancing authority
CCGT	combined cycle natural gas turbine
CSP	concentrating solar power
DG	distributed generation
DNI	direct normal insolation
DOE	U.S. Department of Energy
EERS	energy efficiency resource standard
EGS	enhanced geothermal systems
EPE	El Paso Electric Company
IOU	investor-owned utility
IRP	integrated resource plan
ISO	independent system operator
ITC	investment tax credit
GDP	gross domestic product
GW	gigawatt
GWh	gigawatt-hour
LADWP	Los Angeles Department of Water and Power
LBNL	Lawrence Berkeley National Laboratory
MPR	market price referrent
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NPC	Nevada Power Company
NREL	National Renewable Energy Laboratory
OATT	open access transmission tariff
PG&E	Pacific Gas & Electric Company
PNM	Public Service Company of New Mexico
PRC	New Mexico Public Regulation Commission
PSCO	Public Service Company of Colorado
PTC	production tax credit
PUC	public utilities commission
PV	photovoltaic
QRA	qualified resource area
REC	renewable energy certificate/renewable energy credit
Recovery Act	American Recovery and Reinvestment Act of 2009
RES	renewable energy standard
RETI	California Renewable Energy Transmission Initiative
RPS	renewable portfolio standard
RRS	renewable resource standard
SDG&E	San Diego Gas & Electric Company

SMUD	Sacramento Municipal Utility District
SPPC	Sierra Pacific Power Company
SPSC	State/Provincial Steering Committee
SRP	Salt River Project
TEP	Tucson Electric Power Company
TWh	terawatt-hour
WGA	Western Governors' Association
WREZ	Western Renewable Energy Zones

Executive Summary

Several Western states have renewable portfolio standard (RPS) requirements that have driven significant expansion of wind, solar, and geothermal power. This study examines the renewable energy resources likely to remain undeveloped in the West by the time all these requirements have culminated in 2025. Development beyond that point will likely depend on the best of these remaining resources—where they are located, what it takes to get them to market, and how cost effectively they fit into a diverse portfolio of electric generation technologies.

While the bulk of this study concerns future renewable energy supply, its aim is to reduce some of the present uncertainty that complicates long-term planning. These findings about the renewable resources likely to be available in 2025 can inform today's discussions about policies targeting future development—policies that might be different from the RPS model. Many important factors outside the scope of this study are likely to affect what those policies are. The aim here is not to recommend a path, but to assess the supply conditions that—with many other factors—might affect future state policies and utility business decisions.

So far, most western utilities have relied primarily on renewable resources located close to the customers being served. This appears to be enough to keep most states on track to meet their final RPS requirements. What happens next depends on several factors that are difficult to predict at this point in time. These factors include trends in the supply and price of natural gas, greenhouse gas and other environmental regulations, changing consumer preferences, technological breakthroughs, and future public policies and regulations. Changes in any one of these factors could make future renewable energy options more or less attractive.

Nevertheless, it is possible to characterize the stock of renewable resources likely to remain undeveloped after RPS requirements are met, and to do so with a reasonably high degree of confidence. That is the purpose of this report. While the study does not by itself answer questions about where future energy supplies should come from, it does reduce some of the uncertainty about one type of alternative: utility-scale renewables developed for a regional market.

This study divides the timeline of renewable energy development into two periods: the time covered by state RPS policies as they exist today, and what may be termed "next generation" renewable energy policies. In the West, the last state RPS culminates in 2025, so the analysis uses 2025 as a transition point, as illustrated in Figure ES-1. Next-generation policies may be simple extensions of existing RPS mandates, or innovative tools specifically designed to address new conditions in the electric sector.

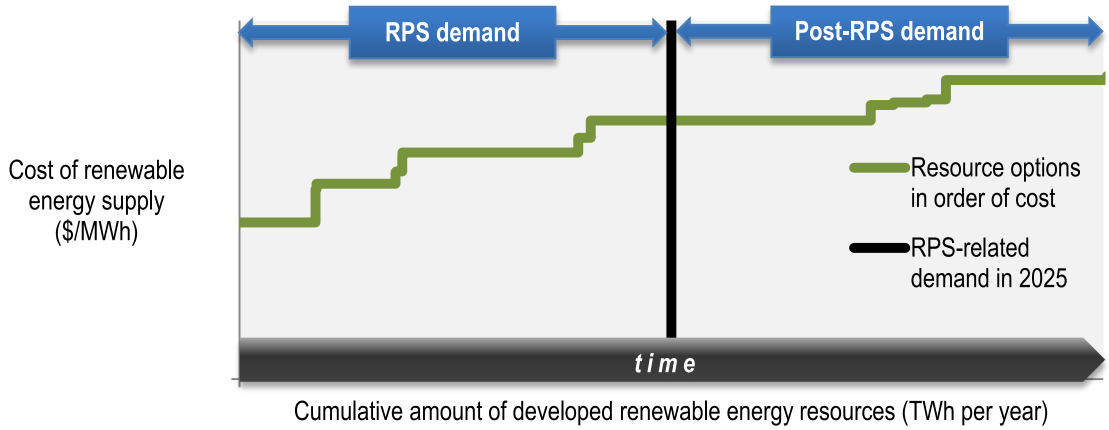


Figure ES-1. Conceptual renewable energy supply curve

Best-Value Propositions for Post-2025 Regional Renewables

"Value proposition" means there is reasoned justification for believing that a corresponding investment in infrastructure would be responsive to a foreseeable demand if it were built. The stronger the potential value, the more likely it would be that renewable resource developers would compete for that future opportunity. In some cases, realizing a value proposition could depend on regional cooperation for new transmission.

A number of corridors with positive value propositions stand out. They generally cluster around two destination markets: California and the Southwest; and the Pacific Northwest. Most involve deliveries of wind power, but in some circumstances solar and geothermal power may offer targeted opportunities for value.

Wyoming and New Mexico could be areas of robust competition among wind projects aiming to serve California and the Southwest. Both states are likely to have large amounts of untapped, developable, prime-quality wind potential after 2025. Wyoming's surplus will probably have the advantage of somewhat higher productivity per dollar of capital invested in generation capacity; New Mexico's will have the advantage of being somewhat closer to the California and Arizona markets.

Montana and Wyoming could emerge as attractive areas for wind developers competing to meet demand in the Pacific Northwest. The challenge for Montana wind power appears to be the cost of transmission through the rugged forests that dominate the western part of the state.

Wyoming wind power could also be a low-cost option for Utah. This could complement Utah's own diverse portfolio of in-state resources.

Colorado is a major demand center in the Rocky Mountain West and will likely have a surplus of prime-quality wind potential in 2025. However, the results suggests that especially high transmission costs could be a formidable economic obstacle to future renewable energy trading between Colorado and its Rocky Mountain neighbors.

California, Arizona, and Nevada are likely to have surpluses of prime-quality solar resources. None is likely to have a strong comparative advantage within the three-state market, unless environmental or other siting challenges limit in-state development. Of the three, California is the most economically attractive destination market, as indicated by the competitive benchmark used in this study. Development of utility-scale solar will probably continue to be driven by local needs rather than export potential.

New geothermal development could trend toward Idaho by 2025. Much of Nevada's known geothermal resource potential has already been developed, but to date very little of Idaho's has. Geothermal power from Idaho could be competitive in California as well as in the Pacific Northwest, but the quantity is relatively small. Reaching California, Oregon, and Washington may depend on access to unused capacity on existing transmission lines, or on being part of a multi-resource portfolio carried across new lines.

Surplus Prime-Quality Resources in 2025

The analysis begins with a detailed state-by-state examination of renewable energy demand and supply projected out to 2025. The purpose of the state analyses is to forecast where the largest surpluses of the most productive renewable resources are likely to be after all current RPS policies in the West culminate. Table ES-1 summarizes the findings.

Table ES-1: Major Findings about Surplus Resources in 2025

The western states together will need between 127 TWh and 149 TWh of renewable energy annually in 2025 to meet targets stipulated by current state laws. California accounts for nearly 60% of this RPS-related demand.
Renewable energy projects either existing or under construction in the western United States as of 2012 can supply an estimated 86 TWh.
Colorado, Montana, Nevada, and New Mexico each has within its borders more untapped prime-quality renewable resources than it needs to meet the balance of its forecasted requirement for 2025.
Wyoming and Idaho have no RPS requirement, but they provide renewable energy to other states and have large undeveloped supplies of prime-quality renewable resources.
Arizona has sufficient high-quality solar resources to meet the balance of its forecasted requirement for 2025. It has a limited amount of non-solar resources, none of which is likely to be competitive outside the state.
California, Oregon, Utah, and Washington have already developed most (if not all) of their easily developable prime-quality in-state renewable resources. Their less productive renewable resources could be sufficient to meet the balance of their forecasted 2025 requirements, but the cost is likely to be higher than the cost of renewable power developed prior to 2012.

In this analysis, “prime-quality renewable resources” means: wind areas with estimated annual capacity factors of 40% or better; solar areas with direct normal insolation of 7.5 $kWh/m^2/day$ or better; and all discovered geothermal resources.

Renewable Resource Screening and Analytical Assumptions

This report relies on updates to the wide-area renewable energy resource assessment conducted under the Western Renewable Energy Zone (WREZ) Initiative for the Western Governors' Association. The purpose of the WREZ assessment was to locate the West's most productive utility-scale renewable energy resource areas—zones where installed generation would produce the most electricity for each dollar invested.[1] The assessment took into account the quality of natural factors, such as windiness and annual sunshine, as well as limiting factors, such as national parks, wilderness areas, and terrain that was too rugged for development.[2] Prime-quality renewable resources are a subset of the screened WREZ resources.

Four assumptions guide forecasts of the prime resources likely to remain untapped by 2025:

- Utilities will prefer using in-state prime resources to meet their RPS requirements
- Prime out-of-state resources will not be preferred unless there are no more prime in-state resources
- Only surplus prime resources will have a meaningful place in a regional post-2025 market
- Utilities will prefer a diversity of resource types in their RPS compliance portfolios.

These assumptions are consistent with feedback from utility planners and regulators obtained as part of the WREZ Initiative.

While the WREZ analysis is the most comprehensive renewable energy assessment conducted for the western United States to date, there are some shortcomings that have a potential effect on the assumptions underlying this analysis. Resources that might be good enough for local use but are unlikely to be competitive in a regional market were not screened and quantified with the same rigor as were higher quality resources because they were outside the scope of the WREZ analysis. Unique characteristics and a short interconnection distance could make an isolated non-WREZ site unusually productive, even if there was no evidence of systematic quality across the larger area. A large number of such undetected areas could result in underestimating the nearby supplies capable of meeting post-2025 demand economically. It could also lead to underestimating the prime resources likely to remain undeveloped by 2025.

[1] The strict technical meaning of the term “productive,” as used throughout this report, is a generator's annual capacity factor—the unit's actual electricity production expressed as a percentage of the electricity that the equipment would produce if it were running at its full rated capacity all the time.

[2] Mountains and other steep terrain (e.g. , greater than 20% slope for wind power) were considered too difficult to develop and were excluded. Lack of nearby transmission was not a criterion for exclusion, as the purpose of the WREZ analysis was to help inform planning for new transmission.

Another caveat is that small-scale renewable DG is outside the scope of this particular study. This does not diminish the importance of DG as a long-term resource. Rather, it recognizes that DG and utility-scale renewables face different issues of comparable complexity and are best analyzed on their own merits separately. DG and the development of utility-scale prime renewable resources are not mutually exclusive; nevertheless, aggressive state DG policies could reduce demand for new utility-scale generation resources of any type, which in turn could reduce demand for prime renewables developed regionally.

Competitiveness of Future Surpluses in Destination Markets

The study then moves from the state resource analyses to examine the value of delivering the region's best surplus resources to the West's largest demand centers. The test for competitiveness is the difference between the delivered cost of the best 1,000 GWh of prime renewable resources likely to remain undeveloped in 2025 and a cost benchmark for the destination market. The benchmark is based on the projected future cost of a new combined-cycle natural gas turbine (CCGT) built in the destination market, with natural gas in 2025 at a nominal price of between $7.50/mmBtu and $8.43/mmBtu. In the case of wind and solar power, we adjust the benchmark to account for how well electrical production from the renewable resource matches load in the destination market hour to hour.

The study does not make an assumption about future federal or state renewable energy policies past their current expiration or target dates. Cost estimates do not include the production tax credit (PTC) or the investment tax credit (ITC). One aim of this analysis is to provide a baseline picture of the renewable energy market in 2025 before adding in the effect of future policies, whatever they might be. A plausible baseline can provide important input for designing future state and federal policies.

Drawing on earlier work, this study assumes the following cost changes from 2012 to 2025:[3]

- <u>Wind power</u>: All-in costs will decrease 19% on a constant-dollar basis and will increase 9% in nominal dollars
- <u>Solar power</u>: All-in costs will decrease 35% on a constant-dollar basis and will decrease 5% in nominal dollars
- <u>Geothermal power</u>: All-in costs will decrease 9% on a constant-dollar basis and will increase 19% in nominal dollars
- <u>CCGT (benchmark value)</u>: All-in costs will remain unchanged on a constant-dollar basis and will increase 29% in nominal dollars; the nominal price of natural gas for electric

[3] Wind power cost estimates are based on: Lantz, E.; Wiser, R.; Hand, M. *IEA Wind Task 26: The Past and Future Cost of Wind Energy*. NREL/TP-6A20-53510. Golden, CO: National Renewable Energy Laboratory, May 2012. Cost estimates for solar and geothermal power are based on: Augustine, C.; Bain, R.; Chapman, J.; Denholm, P.; Drury, E.; Hall, D.G.; Lantz, E.; Margolis, R.; Thresher, R.; Sandor, D.; Bishop, N.A.; Brown, S.R.; Cada, G.F.; Felker, F.; Fernandez, S.J.; Goodrich, A.C.; Hagerman, G.; Heath, G.; O'Neil, S.; Paquette, J.; Tegen, S.; Young, K. *Renewable Electricity Futures Study Volume 2: Renewable Electricity Generation and Storage Technologies*. NREL/TP-6A20-52409-2. Golden, CO: National Renewable Energy Laboratory, 2012. CCGT and natural gas costs are based on the California Public Utility Commission's Market Price Referrent, *Resolution E-4442.* Public Utilities Commission of the State of California (Dec. 1, 2011). Section 3 of this report discusses in further detail the approach for estimating future costs.

generation will range from $7.50 per mmBtu to $8.40 per mmBtu at major trading hubs in 2025.

As explained below, the study applies a sensitivity analysis to test the robustness of its conclusions if future costs differ from these estimates.

Significant technological breakthroughs or other developments could have implications for the assumptions about renewable resource availability and effective per-megawatt-hour cost. For wind power, technological breakthroughs in turbines designed for moderate wind speeds could improve the productivity of sites that are less productive using current technologies. This could reduce the cost differential between remote prime-quality wind resources and local wind resources of moderate quality. Much of this improvement has already taken place and is captured in the cost estimates used for this study, but additional improvements are possible.

Estimates for geothermal power account for advancements in engineered geothermal systems (EGS). Pilot projects suggest that including an EGS component in new infrastructure at sites with known geothermal potential could increase productivity by 25% and could reduce total costs (on a per-megawatt-hour basis) by 2%.[4] In this study, these adjustments to quantity and cost are applied to known geothermal potential that had not yet been developed as of 2013.

Excluded from the analysis is a large amount of geothermal potential currently categorized as "undiscovered." Its existence is inferred from statistical models of the spatial correlation of geologic factors that are indicative of geothermal systems, but its specific location is unknown. If more undiscovered resources can be located, the amount of developable geothermal potential incorporated into long-term regional planning could increase. Predicting the quantity is infeasible at this point because of insufficient data and the lack of a sound forecasting methodology. For the purposes of this study, we assume that the unknown increase in discovered geothermal resources will mostly offset the unknown decrease in future geothermal potential that may be due to some sites with known potential not being developed.

The analysis assumes that the shape of hourly load profiles in destination markets will not change appreciably between 2012 and 2025. The valuation methodology gives greater economic weight to power delivered on peak, and this adds to the value of solar power. If actual profiles were to trend flatter—that is, future midday load peaks are less pronounced than they are today—solar resources would have a smaller time-of-delivery value adder. Similarly, one case study indicates that solar power's capacity value (i.e., the value of its ability to deliver power at peak times) diminishes at higher penetration rates, although the trend is significantly less for concentrating solar power with thermal storage.[5]

We include a new approach to estimating future transmission and integration costs, noting, however, that future transmission costs and grid integration costs are difficult to forecast with precision. This study tests whether the difference between current delivered cost and the benchmark is large enough to accommodate a hypothetical doubling of current transmission

[4] "Nevada Deploys First U.S. Commercial, Grid-Connected Enhanced Geothermal System," Washington, D.C.: U.S. Department of Energy, April 12, 2013.

[5] Mills, A. and Wiser, R. "Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California." LBNL-5445E. Lawrence Berkeley National Laboratory: Berkeley, CA, 2012.

costs.[6] Figure ES-2 illustrates the "two times tariff" approach. A renewable energy zone is treated as having a high potential for value in 2025 if its busbar cost plus double the current transmission charges is less than the benchmark in the destination market.[7]

By basing the methodology on current tariff rates rather than generic cost-per-mile line costs, the analysis accounts for how transmission costs can vary from one area to another. A transmission line of the same size is generally more expensive to build if the route includes mountains and forests, as compared to a route across plains. Juxtaposing estimates from this new approach with more conventional estimates can provide an additional data point for understanding the uncertainty surrounding future transmission costs. In most cases the "two times tariff" approach results in delivered cost estimates that are higher than those suggested by costs of new transmission projects that have been proposed along the same resource-to-market path, indicating that the methodology is appropriately conservative.[8]

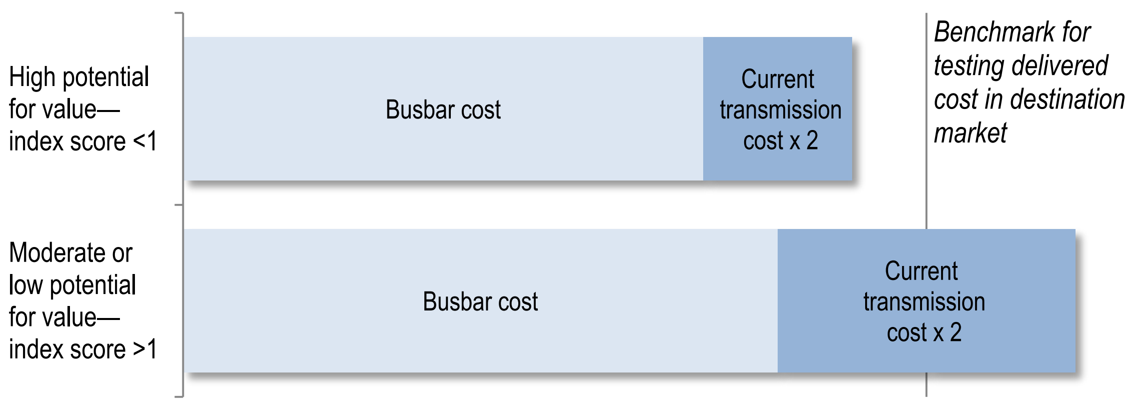


Figure ES-2. Cost benchmarking methodology

[6] We also escalate the doubled rates by 2% annually to account for inflation. Effectively, this methodology estimates that transmission costs will increase faster over the next 12 years than they did over the past 12 years, and that the nominal cost of transmission in 2025 will be 59% higher than what historical trends would suggest.

[7] "Busbar cost" refers to a technology's annualized capital costs plus its annual operating costs, excluding transmission and other costs involved in moving the power from where it is generated to where it is used. "Delivered cost" is the combination of busbar costs, transmission costs, and any grid integration costs that might be assessed.

[8] See Section 3 for a detailed comparison of this methodology with the projected costs of publicly announced major transmission projects in the West.

Table ES-2. Highest-Value Regional Resource Paths Ranked by Index Score

High value potential

	Index Score[a]
Wyoming wind to Nevada	0.79
Wyoming wind to Utah	0.84
New Mexico wind to Arizona	0.94
Wyoming wind to Arizona	0.95
Wyoming wind to California	0.97
Wyoming wind to Washington	1.04
Wyoming wind to Oregon	1.04
New Mexico wind to California	1.06
Nevada solar to California	1.07
Idaho geothermal to California	1.11
Montana wind to Nevada	1.12
Arizona solar to California	1.13
Montana wind to Utah	1.17
Montana wind to Oregon	1.18
Montana wind to Washington	1.19

Moderate value potential

Wind resource
Solar resource
Geothermal resource

[a] An index score less than 1.0 indicates a resource with a delivered cost that is still below the relevant state benchmark even if current transmission costs are doubled. The formula for calculating the score is:

$$\text{index score} = \frac{\text{resource busbar cost} + 2 \times \sum \text{current transmission charges}}{\text{state delivered cost benchmark}}$$

Table ES-1 ranks the 15 resource-to-market combinations that scored highest in the evaluation methodology used in this study:

- Wyoming wind power delivered to Utah, California, Nevada, Oregon, Washington, and Arizona
- Solar power from Nevada and Arizona delivered to California
- New Mexico wind power delivered to California, Arizona, and Utah
- Wind power from Montana delivered to Oregon, Washington, and Utah
- Geothermal power from Idaho to California.

These resource paths have the highest likelihood of being reasonably competitive with natural gas generation in 2025 even if current transmission costs were to double.

Cost Sensitivities

Long-term trends in capital costs are difficult to predict, so this study included a sensitivity analysis to test how a 10% change in a technology's assumed 2025 cost would affect its relative competitiveness as estimated in this study.

The most pronounced cost sensitivity was for utility-scale solar power from Nevada and Arizona delivered to California. If costs were to fall 10% below the base-case assumptions used in this analysis, solar power from Nevada and Arizona would be close to parity with CCGT in California. The two resource paths would rank third and fourth among the potential paths with the greatest likelihood for value in a post-2025 West. A cost decrease would also favor California's own solar resources, however, so the net impact on imports would probably be related to siting constraints.

Results for wind power did not change significantly under different cost assumptions. Wyoming wind delivered to Utah and California remained below or close to parity with natural gas. Other wind resource paths were slightly less competitive.

Paths for geothermal power were sensitive to cost changes. The reduced-cost scenario brought Idaho geothermal to within 10% of competitiveness with natural gas in California. Higher costs, on the other hand, could put geothermal power 30% to 85% above the forecasted cost of a new CCGT in 2025.

Future Competitiveness

Results from this study suggest that geothermal power will likely remain more costly on an all-in, per-MWh basis than equivalent CCGT or other renewable power options in the West out to 2025, barring a significant breakthrough in current technology cost or performance. For wind and solar built in ideal locations, the gap could become small.

Table ES-3. Competitiveness Indicators for Regionally Developed Renewables in 2025

	Difference From Projected Cost of CCGT	
	(%)	($/MWh)
Geothermal ***Idaho to California, Northwest; Nevada to California; Imperial Valley to Arizona***	12%–35% higher	$15–$42 higher
Solar ***Nevada and Arizona to California***	1%–19% higher	$1–$31 higher
Wind ***Wyoming and New Mexico to California and Arizona; Montana and Wyoming to Oregon, Washington, and California***	Parity to 13% higher	Parity to $16 higher

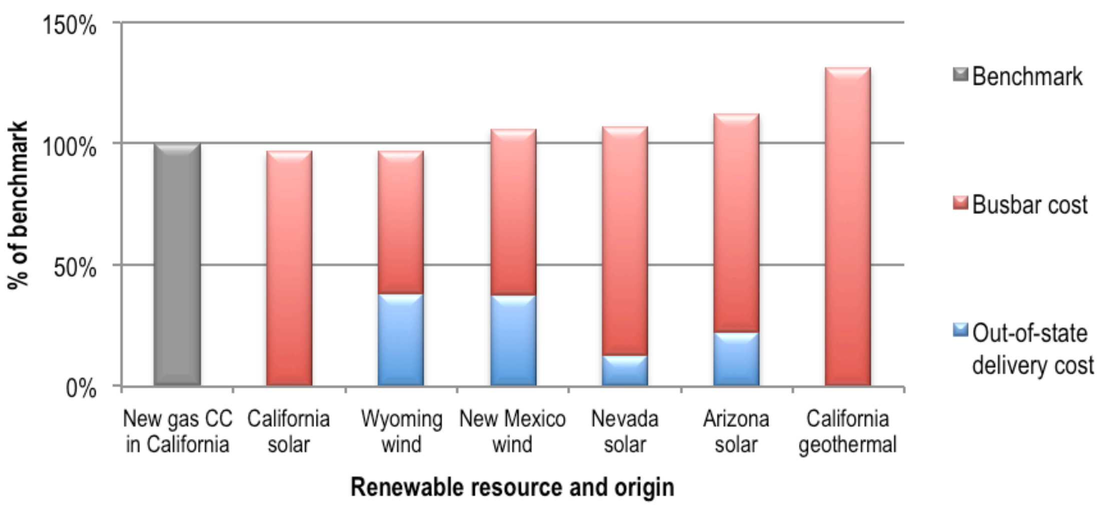
Note: Competitiveness is measured as the difference between the levelized delivered cost of an unsubsidized renewable resource and the levelized cost of a locally sited CCGT, with both values projected to 2025. Values shown here are averages derived from the resource paths indicated. Upper bounds of the ranges shown are calculated after increasing assumed busbar costs by 10%; lower bounds assume busbar costs that are 10% lower. Delivered costs use double current transmission tariff charges to proxy transmission and integration costs in 2025.

Table ES-2 frames the results of the sensitivity analysis in the context of a renewable resource's competitiveness, which is defined and measured here as the difference between the resource's levelized delivered cost without subsidy and the levelized cost of a CCGT built in 2025 in the destination market.

Competitiveness was calculated for the following resource paths:

- Geothermal power: Idaho to California, Oregon, and Washington; Nevada to California; California (Salton Sea) to Arizona
- Solar power: Nevada and Arizona to California
- Wind power: Wyoming and New Mexico to California and Arizona; Montana and Wyoming to Oregon and Washington; Montana to California.

Figure ES-3 compares the relative economic competitiveness in California of six renewable resource options, as estimated in this analysis. For each option shown on the chart, empirical evidence exists suggesting that large surpluses will be available in 2025. Most are likely to be close to the cost of a new CCGT, even if their busbar costs turn out to be 10% higher than the baseline estimates used in this analysis. The results suggest that, once the state achieves its current RPS goal in 2020, looking regionally for additional renewable energy supplies could provide California with reasonable diversity at reasonable cost.



Benchmark is the projected all-in cost of a new CCGT plant built in 2025, as calculated by the California Public Utilities Commission (PUC) for its 2011 market price referent. Busbar costs for wind and solar are adjusted to account for coincidence with California load. Out-of-state delivery costs are approximated using the "two times tariff" methodology mentioned in this summary and detailed in Section 3. Transmission costs within California are assumed to be the same for all resources and are not represented.

Figure ES-3. Cost of resources projected to be available in bulk to California after 2025