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SunShot Solar Power Reduces Costs and Uncertainty in Future Low-Carbon Electricity Systems

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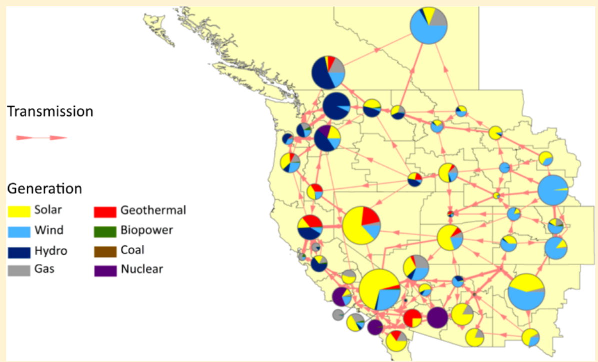
Supporting Information

ABSTRACT: The United States Department of Energy's SunShot Initiative has set cost-reduction targets of \$1/watt for central-station solar technologies. We use SWITCH, a high-resolution electricity system planning model, to study the implications of achieving these targets for technology deployment and electricity costs in western North America, focusing on scenarios limiting carbon emissions to 80% below 1990 levels by 2050. We find that achieving the SunShot target for solar photovoltaics would allow this technology to provide more than a third of electric power in the region, displacing natural gas in the medium term and reducing the need for nuclear and carbon capture and sequestration (CCS) technologies, which face technological and cost uncertainties, by 2050. We demonstrate that a diverse portfolio of technological options can help integrate high levels of solar generation successfully and cost-effectively. The deployment of GW-scale storage plays a central role in facilitating solar deployment and the availability of flexible loads could increase the solar penetration level further. In the scenarios investigated, achieving the SunShot target can substantially mitigate the cost of implementing a carbon cap, decreasing power costs by up to 14% and saving up to \$20 billion (\$2010) annually by 2050 relative to scenarios with Reference solar costs.



■ INTRODUCTION

The high cost of solar electricity technologies relative to conventional fossil fuel generation has been a barrier to their deployment at large scale. In 2011, solar generation provided less than 1% of electricity in the United States[1] and 3% in Germany.[2] The solar photovoltaic (PV) industry has experienced fast-paced expansion in recent years, with annual growth rates in PV production of at least 40% since 2000.[3] Installed costs for PV declined by 43% between 1998 and 2010,[4] but future cost and performance projections vary widely. In 2011, the United States Department of Energy (DOE) launched the SunShot Initiative, a comprehensive lab-to-market program that seeks to drive innovation and lower the cost of solar technologies, including PV and concentrating solar power (CSP). The cost target for PV is \$1/W for central-station systems and \$1.5/W for residential installations by 2020 (\$2010).[5]

The SunShot Vision Study[6] provides an extensive analysis of the pathway to reaching the SunShot targets and implications for solar deployment in the United States. Similarly, we explore power system dynamics with SunShot solar costs, but, building on the SunShot Vision Study, we focus on scenarios with a carbon cap requiring the electricity sector to reduce its emissions to 80% below 1990 levels by 2050. This target is consistent with the Intergovernmental Panel on Climate Change's (IPCC) 450 ppm (ppm) stabilization target for atmospheric concentration of carbon dioxide equivalent (CO_2-e), which would limit planetary warming to 2 °C above preindustrial levels.[7] Several countries and states already have equivalent policy goals in place. The State of California has put into law a requirement to reduce greenhouse gas emissions (GHG) to 1990 levels by 2020 with Assembly Bill 32 (AB32).[8] In addition, Executive Order S-3-05 calls for a further decline in the state's emissions to 80% below 1990 levels by 2050. At the federal level, President Obama's administration supports the implementation of a cap-and-trade program to reduce GHG emissions to 83% below 2005 levels by 2050.[9] In this work, we explore how the Western Electricity Coordinating Council (WECC) can achieve deep GHG emission reductions in the 2050 time frame. WECC encompasses fourteen Western states, the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja California, Mexico.

We use SWITCH, a capacity-planning model whose goal is to determine the most cost-effective investments in electric power grid infrastructure.[10,11] SWITCH is a linear program (LP) whose objective is to minimize the cost of delivering power to load on an hourly basis subject to operational and policy constraints. The model uses time-synchronized hourly load and intermittent renewable generation data to determine

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optimal investment in and hourly dispatch of generation, transmission, and storage. We use a version of SWITCH developed for the electricity system of the entire WECC.[12,13] We choose to study the WECC power system because of its high-quality renewable resources that would likely make it a prime region for deployment of solar power. The WECC grid would also experience relatively high operational impacts associated with intermittent generation. This work investigates how the cost of solar technologies might affect both the ability of the WECC electricity sector to decarbonize and the costs associated with reducing carbon emissions to the 2050 target.

Scenarios. All scenarios assume a WECC-wide carbon cap requiring the electricity sector to gradually decrease emissions each year to 80% below 1990 levels by 2050 (no banking or borrowing of emissions is allowed). In the *Base Technology Scenario*, we make nuclear and carbon capture and sequestration (CCS) technologies available to the SWITCH optimization. In the *Limited Technology Scenario*, we exclude nuclear and CCS from the potential generator fleet as technological availability in the 2050 time frame is uncertain.

Within each of these scenarios, we explore two solar cost trajectories (Table 1) and compare the resulting power systems.

Table 1. SunShot and Reference Case Costs by Solar Technology

solar technology	year	reference *2010$/W*	SunShot *2010$/W*
central PV	*2020*	2.51	1.00
	2030	2.40	1.00
	2040	2.20	1.00
	2050	2.10	1.00
commercial PV	*2020*	3.36	1.25
	2030	3.21	1.25
	2040	2.95	1.25
	2050	2.81	1.25
residential PV	*2020*	3.78	1.50
	2030	3.61	1.50
	2040	3.31	1.50
	2050	3.16	1.50
CSP 6 h of storage[14]	*2020*	6.64	3.07
	2030	5.23	3.07
	2040	4.61	3.07
	2050	4.61	3.07
CSP no storage	*2020*	4.60	2.50
	2030	4.20	2.50
	2040	3.90	2.50
	2050	3.50	2.50

In the *SunShot* cases, solar technologies achieve the targeted cost reductions by 2020 and then remain at these cost levels through 2050. In the *Reference* cases, solar generation remains more expensive, with costs decreasing gradually between present day and 2050. Finally, we investigate the role of flexible loads in the future WECC grid in the *Flexible Load Scenario*, which is based on the *Limited Technology SunShot Scenario*, but also allows a fraction of load in each hour to be shiftable, starting with 1% of load in the 2020 time frame and reaching 10% of load by 2050.

Costs for other technologies are based on Black and Veatch estimates and projections[15] and can be found in the Supporting Information. Natural gas and coal prices are based on the U.S. Energy Information Administration's Annual Energy Outlook (US EIA AEO) 2011 Reference Case projections.[16]

Model Description. The version of SWITCH used here minimizes the cost of producing and delivering electricity using a combination of existing grid assets and new generation, transmission, and storage. New capacity can be built at the start of each of four "investment periods," representing 2015−2025, 2025−2035, 2035−2045, and 2045−2055. Throughout this manuscript, we also refer to the four investment periods as 2020, 2030, 2040, and 2050, respectively. The investment decisions determine the availability of power infrastructure to be dispatched in each "study hour," sampled from a year of hourly data for each period. Investment and dispatch decisions are optimized simultaneously.

Study hours are initially subsampled from the peak and median load day of every month. Every fourth hour is selected, and dispatch decisions are initially made for (4 periods) × (12 months/period) × (2 days/month) × (6 h/day) = 576 study hours for the entire study. As the main SWITCH optimization uses a limited number of sampled hours over which to dispatch the electric power system, dispatch verification is performed at the end of each optimization to ensure that the model has designed a power system that can meet load reliably. In this verification, investment decisions are held fixed, and new hourly data for two full years are tested in batches of one day at a time. For the scenarios investigated here, several optimization iterations were performed until capacity shortfalls were eliminated from the dispatch verification, each iteration including the hour with the largest capacity shortfall from the previous iteration as well as five more hours for that day, spaced evenly four hours apart. Like the main SWITCH optimization, the dispatch verification enforces transmission constraints as a transportation network only rather than power flow and does not include generator ramping constraints and security constraints.

We use time-synchronized hourly profiles for load and renewable output to account for correlation between demand and renewable generation.[17] Building on our prior work,[12] for this study we have implemented a series of enhancements to SWITCH's treatment of generator types in order to simulate system operations as realistically as possible, at an unprecedented resolution for a capacity-expansion model of a large geographic area. Six categories of generators are operated: baseload, flexible baseload, intermediate, peaker, intermittent, and storage. For this work, we have implemented 1) flexible baseload operation for coal plants, which run around the clock but are allowed to ramp up and down on a daily basis, incurring a heat rate penalty when operating below full load, 2) intermediate operation for combined cycle gas generator turbines (CCGTs), which can vary output hourly, but incur costs and emission penalties when new capacity is started up and heat rate penalties when operating below full load, and 3) startup costs for peaker plants, which have flexible output restricted only by installed capacity. Additional model capabilities implemented as part of this study include the following: operating reserve requirements (spinning and quickstart), flexible loads, a carbon cap constraint, state distributed generation policy goals, and natural gas price elasticity.

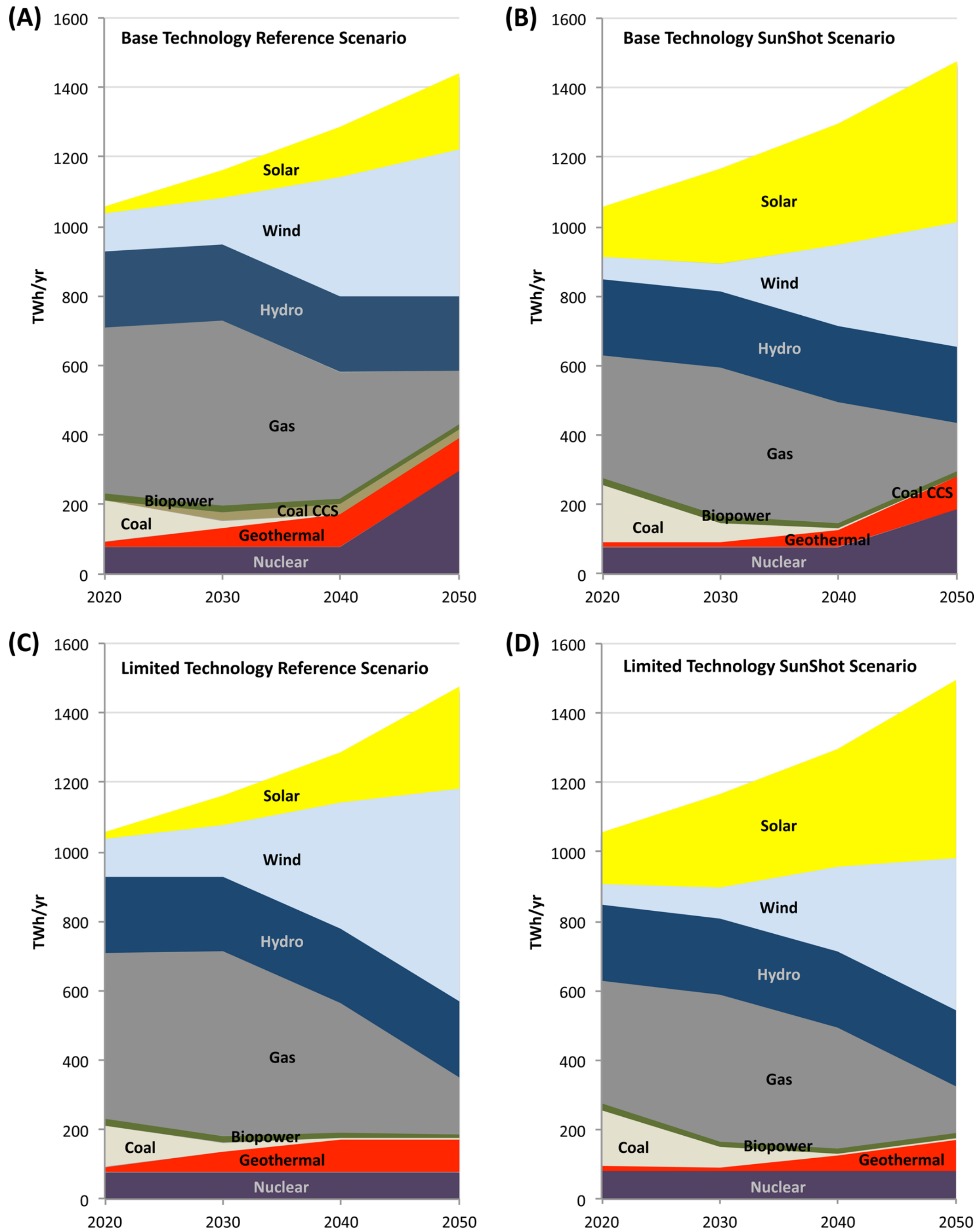

Figure 1. Energy mix by fuel and investment period.

A complete formulation of the version of SWITCH used in this study is available in the Supporting Information and at http://rael.berkeley.edu/switch/.

RESULTS

Base Technology Scenario. In the *Base Technology Scenario*, we allow SWITCH to build new nuclear capacity as well as coal- and gas-fired plants equipped with CCS.

With *Reference* solar costs (Figure 1A), natural gas generation constitutes most capacity additions in the near term and begins to displace coal as the carbon cap becomes more stringent over time. If natural gas prices were to remain as currently projected and carbon policies were implemented, this fuel would likely play a dominant role in the WECC power system in the next two decades. By 2030, natural gas plants generate 46% of the total WECC energy, while wind and PV produce 12% and 7% of generation, respectively. Geothermal (5%) and a small amount of biogas (1%) help meet the renewable portfolio standards (RPS) in WECC states with such policies in place.

In the *SunShot* case (Figure 1B), the availability of low-cost solar delays the deployment of low-carbon baseload capacity. In the *Reference* case, new geothermal installations provide 5% of energy in the 2030 time frame to help meet the RPS and carbon cap requirements. By contrast, the *SunShot* case sees geothermal energy use at levels less than 1% before 2040. Similarly, CCS deployment is deferred: with *Reference* solar costs, coal CCS first appears in the power mix as early as 2030, providing 2% of energy in that time frame; in the *SunShot* case, CCS installations are negligible through 2050. Delaying the need to deploy these technologies would allow for additional

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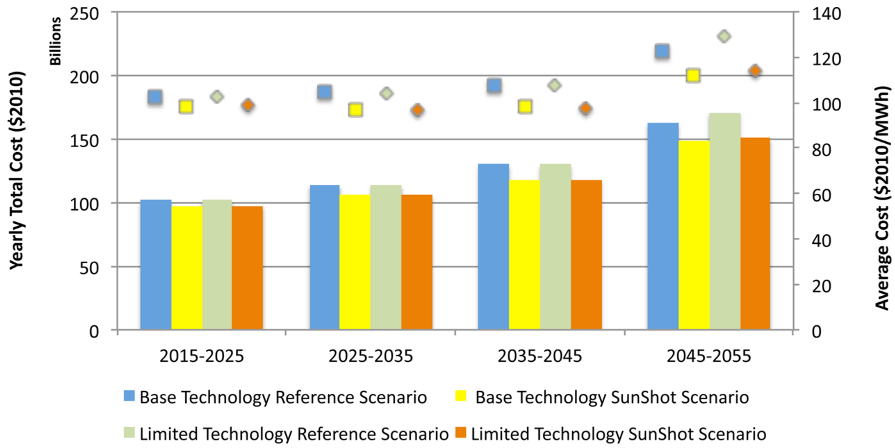

Figure 2. Yearly total cost of power (columns, left axis) and average cost of power (points, right axis) in the WECC in each of the four investment periods in the Base Technology Scenario and Limited Technology Scenario with and without SunShot solar costs. All costs are specified in real terms indexed to the reference year 2010. During the optimization, a real discount rate of 7% is used, so that costs incurred earlier in the study are weighed more heavily.

time to gauge their feasibility and costs and to improve their performance.

By displacing natural gas and the associated emissions, large-scale solar deployment could allow the system to remain within the cap even without other low-carbon resources. Relative to the *Base Technology Reference Scenario*, the share of solar energy increases from 7% to 24% in the 2030 time frame. Instead of intermediate and peaker gas generation, PV, whose output exhibits a positive correlation with the WECC demand profile, helps meet the daily peak load.

By 2050, the carbon cap induces transformative changes in the power mix. The need to reduce emissions limits the amount of natural gas in the system, lowering its energy share to 11% in the *Base Technology Reference Scenario*. Instead, a combination of low-carbon resources helps to meet load. Solar and wind provide 15% and 29% of energy, respectively. Nuclear, geothermal, biopower, and coal CCS make up the balance of generation at 21%, 7%, 1%, and 2%, providing low-carbon baseload power. Hydro generates 15% of energy, and storage also plays a role with 5 gigawatts (GW) of new capacity in the WECC.

In the *Base Technology SunShot Scenario*, the penetration of intermittent renewable energy is even higher. Solar generates 31% of energy and wind's share is 24% in the 2050 time frame. Natural gas provides 9% of energy and is an important source of flexibility. Hydro also helps balance renewables and generates 15% of energy. In addition, 27 GW of storage are installed throughout the WECC, about 5% of total system capacity and more than five times the new storage capacity in the *Reference* case. Geothermal provides 6% of electricity, and the share of nuclear is 13%. Relative to the 2030 dynamics, the trade-off between solar and natural gas is less prominent in the 2050 time frame because the amount of natural gas is limited by the carbon cap rather than by fuel costs. Instead, the solar resource in the *SunShot* case displaces mostly nuclear energy relative to the case with *Reference* solar costs.

Limited Technology Scenario. In addition to technical issues around waste disposal and reactor safety, nuclear power today faces cost and public acceptance challenges. To date, CCS has not been deployed at scale, and many CCS system components are still in the research, development, and demonstration phase. To explore a future in which low-carbon baseload power like nuclear and CCS is not readily available in a carbon-constrained system, we remove these technologies from the set of investment options in the *Limited Technology Scenario* and rerun the optimization with both *Reference* (Figure 1C) and *SunShot* (Figure 1D) solar costs.

In this scenario, the power mix remains similar to that in the *Base Technology Scenario* until the last investment period. However, as the carbon cap becomes more stringent over time leading up to the 2050 goal, the system changes substantially between the two. Without nuclear power and CCS technology – and with solar costs remaining high in the *Limited Technology Reference Scenario* – the power system relies on large-scale deployment of wind energy in order to meet the cap. Wind deployment expands in the last investment period: more than 200 GW of wind power are in operation by 2050, providing 42% of energy in the 2050 time frame. The share of solar energy is 20%. About 11 GW of storage are also installed.

When SunShot targets are reached, both solar and wind generation increase relative to the *Base Technology SunShot Scenario* to make up for the lack of nuclear and CCS, reaching 34% and 30% respectively by 2050. The balance of generation remains similar across scenarios: geothermal provides low-carbon baseload energy, while hydropower and gas generation contribute to both the energy and flexibility needs of the power system.

Cost of Power. The cost of power increases over time across scenarios (Figure 2). However, SunShot solar availability contributes to a decline in cost relative to the *Reference* solar cost cases. In the last investment period in the *Base Technology Scenario*, the cost of power is \$123/MWh with *Reference* solar costs and \$112/MWh with *SunShot* solar costs. The difference is even more pronounced when nuclear and CCS technologies are unavailable to help meet stringent carbon targets in the 2050 time frame. In the *Limited Technology Scenario*, the average cost of power rises to \$129/MWh by 2050 with *Reference* solar costs. If the SunShot target is reached, the cost of power is \$114/MWh.

Achieving SunShot targets mitigates the cost of carbon reductions in the WECC. While meeting the 2050 carbon cap appears possible with or without SunShot technology, when solar costs remain as in the *Reference* case, the cost premium for reaching the carbon target is 10% in the *Base Technology*

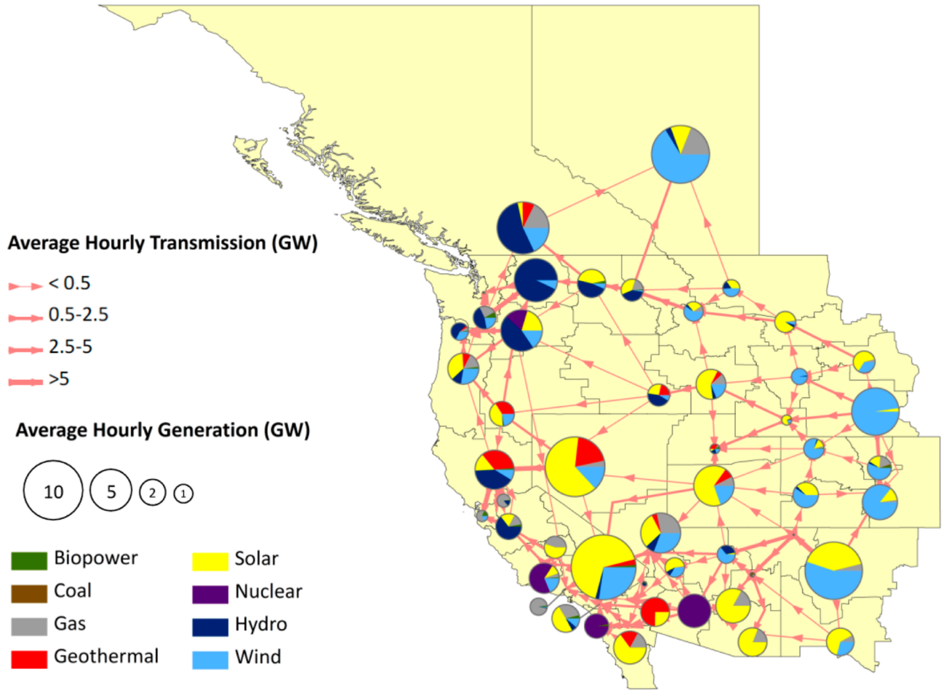

Figure 3. Map of generation and transmission in the Limited Technology SunShot Scenario.

Scenario and 14% in the *Limited Technology Scenario* in the 2050 time frame. In the *Base Technology Scenario*, SunShot solar costs contribute to a decline in power costs in the medium-term time frame. Only in the final decade of the simulation does the cost of power begin to rise relative to costs in the first investment period.

If SunShot solar is unavailable in the 2050 time frame, the lack of nuclear and CCS in the *Limited Technology Scenario* increases the power cost by an additional 5% above the cost in the *Base Technology Scenario*. In contrast, when the SunShot targets are achieved, removing low-carbon baseload from the set of investment options increases power cost by only 1%, thus mitigating the risk associated with nuclear and CCS.

Infrastructure Deployment. Realizing the benefits of SunShot would require large build-out of solar capacity and new transmission in western North America (Figure 3). In the *Limited Technology SunShot Scenario*, PV is installed throughout the WECC, with large capacities built in the Desert Southwest but also in places with lower solar insolation including Alberta, Montana, Oregon, and Wyoming, among others. Transmission expansion is also necessary to bring the solar resources to the load centers. In the *Limited Technology SunShot Scenario*, 28,000 GW-km of new high-voltage, long-distance transmission are installed by 2050. However, the most new transmission − more than 50,000 GW-km − is built in the *Limited Technology Reference Scenario*, largely due to higher levels of wind power deployment in Montana, Wyoming, and Colorado, requiring long transmission lines to bring the wind energy to the load centers. For comparison, the existing transmission capacity input into SWITCH is approximately 71,000 GW-km.

PV capacity increases gradually over time, reaching 96 GW of central-station installations in 2030 and 185 GW in 2050 in the *Limited Technology SunShot Scenario*. Assuming PV array power density of 48 W_{DC}/m^2 for 1-axis tracking systems,[18] this would require close to 400,000 ha (ha) or roughly 0.08% of the land area of the WECC. Central-station solar and wind power plants face permitting, environmental, and transmission-access challenges, which may be a barrier to GW-scale deployment of these technologies. Renewable generation sites should be selected to minimize impacts on environmentally or culturally sensitive areas. The availability of multiple low-cost and low-carbon technologies could mitigate the siting risk associated with any one of them.

In the 2050 time frame, 5 GW of CSP with 6 h of storage are also installed, largely in California. As SWITCH does not yet model CSP with longer storage duration nor does it have decision variables for CSP storage dispatch,[19] these results likely underestimate the economic potential of CSP were it to reach the SunShot cost targets. CSP with 12 to 14 h of storage could provide dispatchable power around the clock, increasing system flexibility and providing important value not captured here.[20] However, the water requirements of CSP plants using evaporative cooling may be a limiting factor in its deployment as water is scarce in the WECC region.

More than 6 GW of distributed PV capacity are also deployed in the WECC in the *Limited Technology Scenario*. This deployment is driven by local incentives already in place such as the California Solar Initiative, which SWITCH enforces. Beyond existing subsidies, distributed PV is outcompeted by less expensive central-station PV in the model's cost-optimization framework. Distributed PV may have net benefits for the distribution network not captured by SWITCH.[21] As a large-scale capacity-planning model, SWITCH also does not capture the set of decisions and market dynamics that may drive distributed PV adoption regardless of cost, including a complicated and geographically varied range of policies, incentives, retail rate structures, and individual preferences.[22]

The scenarios presented above assume annual load growth of 1% as projected by the Energy Information Administration.[23] Implementing additional energy efficiency measures and reducing the amount of load that needs to be served could greatly decrease the capacity build-out required to serve load reliably. For example, if technology assumptions were as in the *Limited Technology SunShot Scenario* but load were to remain at

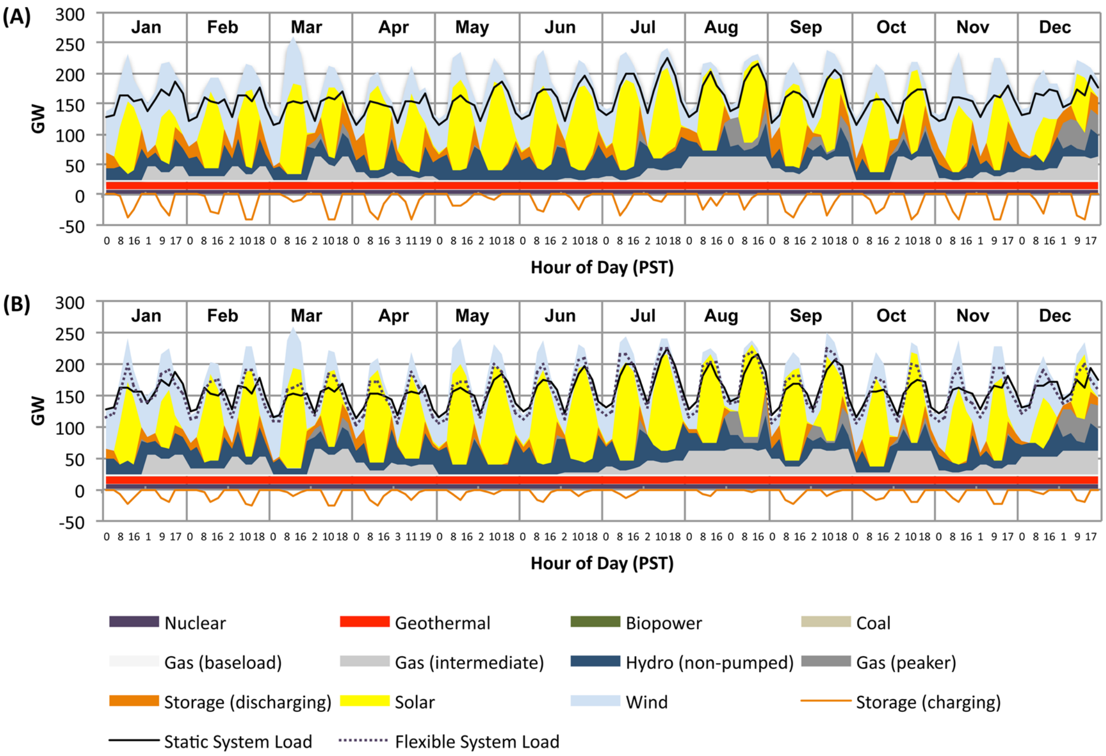

Figure 4. *System dispatch in 2050 in the (A)* Limited Technology SunShot Scenario *and (B)* Flexible Load Scenario. *Total generation exceeds system load because of transmission, distribution, and storage losses as well as curtailment of generation on resources.*

current levels (0% annual load growth), wind and solar capacity requirements would be cut in half and annual power system costs would be reduced by close to $60 billion annually or more than 40% by 2050. The value of energy efficiency will vary depending on the cost of generation available to meet load. Estimating the energy efficiency potential and costs is an important area of research because investing in efficiency may be a cost-effective alternative to deploying generation capacity.

System Dispatch. With intermittent renewable penetration reaching 64% in the *Limited Technology SunShot Scenario*, the power system faces operational challenges, which are evident from the aggregate dispatch of the WECC power system in 2050 as optimized by SWITCH (Figure 4A). Significant system flexibility is required in the early evenings when solar generation ramps down earlier than load, resulting in a need for a steep up-ramp to follow the net load (load minus intermittent generation). In SWITCH's simulations, these net-load ramps are handled by a combination of hydro, storage, and intermediate and peaker gas generation. Combined-cycle gas plants are frequently operated at part load, gas combustion turbines are started up and cycled down as needed, and the existing flexibility from hydropower as well as pumped hydro storage is used extensively. In addition, multi-GW-scale deployment of new storage occurs by the last investment period, comprising 6% of system capacity in the 2050 time frame.

As the least expensive storage option in SWITCH, almost all of the new storage is compressed air energy storage (CAES), with more than 29 GW installed throughout the WECC.[24] About 3 GW of battery capacity are also deployed. Storage deployment occurs in wind regions such as Colorado and Wyoming (~1 GW deployed in each), but most is built in the Desert Southwest to help handle the evening solar down-ramp. This is apparent from the dispatch pattern of storage (Figure 4A), which tends to charge during the peak load hours in the middle of the day — when solar generation is also peaking and net load is low — and discharge in the evening when the sun goes down but load does not decline as rapidly and net load is high. Storage dispatch is different from present-day patterns of charging during the night when demand and prices are low and discharging at peak when prices increase. Notably, storage is less active during the times when the most energy is spilled (the median load day in March in this simulation) as prices stay low throughout the day and little opportunity for arbitrage exists (SWITCH does not currently model seasonal storage). Energy is spilled in the spring and early summer when both the solar and wind resource are abundant while load is low throughout the day.

Like storage, load flexibility could contribute to system reliability and lower system costs. We investigate system dynamics in one additional scenario — the *Flexible Load Scenario* — that has the same technological availability assumptions as the *Limited Technology SunShot Scenario* but includes the ability to shift loads within each day of the optimization. Specifically, we assume that 1% of load in each hour will be shiftable in 2020, 4% in 2030, 7% in 2040, and 10% in 2050. We give SWITCH the option to shift load to any hour within the day without cost or efficiency penalty.

Flexible loads are shifted toward the solar peak when an abundant low-cost and low-emission resource is available and away from the evening net-load peak (Figure 4B). The share of solar in the energy mix rises to 37%, while storage deployment is reduced to 18 GW (from 34% and 29 GW, respectively). The average cost of power in 2050 is $108/MWh, 5% lower than in the *Limited Technology SunShot Scenario*. This benefit would have to be compared against the cost of load flexibility programs.

SWITCH does not yet model a number of power system services such as automatic generation control (AGC), subhourly load following, inertial response, or primary contingency reserve (frequency response), currently incorporating only secondary contingency reserves (spinning and quickstart). In the results presented here, very little thermal generation is dispatched during certain times of the year, e.g. almost no gas generation is operated in May and June. The ability of the power system to maintain frequency after a contingency without traditional synchronous generators is a current research topic. While wind,[25] solar,[26] high-power storage technologies,[27] and flexible load[28] may be able to provide similar response, additional constraints may have to be incorporated into capacity-planning models such as SWITCH to ensure that the simulated system can operate reliably.

■ DISCUSSION

Achieving the SunShot target could make it cost-effective for solar power to provide more than a third of electricity in the WECC by 2050, aiding the ability of the WECC power system to reduce emissions while meeting load. Flexible load availability could increase this penetration level by moving additional load to the solar peak. While not included here, changes in the load profile such as from energy efficiency measures, inflexible nighttime charging of electric vehicles, or heating electrification could have the opposite effect.[13]

Without low-cost solar energy, the WECC power system relies on low-carbon baseload technologies to achieve the 2050 emission goals: in the *Reference Base Technology Scenario*, 27 GW of new nuclear and 4 GW of coal CCS capacity are built. If low-carbon baseload technologies are available, the cost to meet the 2050 carbon cap increases by 10% if the SunShot targets are not reached, a cost premium of $14 billion annually in the 2050 time frame. If nuclear and CCS are not available, SunShot solar can substantially mitigate the cost increase from implementing a strict carbon cap, saving 14% or more than $20 billion annually by 2050. By comparison, the proposed budget for the SunShot program is $310 million for FY2013.[29] Achieving the SunShot target could decrease electricity prices in the medium term and provide key benefits by containing power costs even as stringent decarbonization of the power sector is implemented, potentially facilitating the passage of climate policy. While not included here, possible further cost declines beyond the SunShot target would imply even larger savings.

When SunShot solar is available, removing nuclear and CCS from the investment portfolio does not result in a sharp increase in costs. Achieving the SunShot target might therefore have the additional benefit of serving as insurance against the risk associated with relying on nuclear power and CCS for emission reductions. Delaying the need to deploy those technologies would also allow time for the R&D, innovation, and technological progress to make them a viable, cost-effective alternative for climate change mitigation.

We find that the 2050 emissions target can be achieved in the WECC electricity sector with or without SunShot solar power. Even if SunShot-level technological improvement is not achieved, however, it may still be cost-effective for solar as well as wind generation to make a significant contribution to energy supply in future low-carbon systems. Of the scenarios presented here, the lowest combined energy penetration level for these two intermittent technologies in 2050 is 44% (29% for wind and 15% for solar in the *Base Technology Reference Scenario*), a deployment level that will likely require changes to system operations and additional system flexibility resources.

SWITCH incorporates many elements of system dispatch in a capacity-expansion modeling framework and offers some of the most detailed treatment to date of day-to-day operations in an investment model. The SWITCH results presented here indicate that a range of system flexibility resources, including flexible gas-fired generation, hydroelectric generation, storage, and load response, can help to integrate large amounts of intermittent energy resources into the WECC power system. While technology availability may not be a limiting factor in achieving deep emission reductions with wind and solar, well-designed market mechanisms and policy structures may need to be put in place — in addition to long-term policy support for climate goals — to ensure coordinated investment in R&D and infrastructure, and efficient deployment of enabling technologies such as storage, demand response, flexible transmission, and active controls. It is important to continue investigating how to design a comprehensive strategy to create a least-cost, low-carbon electricity supply system.

Technological breakthroughs such as SunShot could potentially transform the WECC power system and mitigate the cost of emission reductions and the risk of failing to meet the 2050 climate goals. Achieving SunShot costs for solar technologies would require significant technological progress and a supporting policy framework: an increase in the solar industry's manufacturing capacity, streamlined permitting and siting for new plants and transmission lines as well as appropriate markets, policy, and operational practices. Provided strategic long-term planning is put in place, SunShot solar power appears poised to play a crucial role in containing electricity costs even as aggressive carbon emission reduction goals are achieved.

■ ASSOCIATED CONTENT

Supporting Information

A complete description of the version of the SWITCH model and data used here. This material is available free of charge via the Internet at http://pubs.acs.org.

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Notes

The authors declare no competing financial interest.

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