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Power system balancing for deep decarbonization of the electricity sector

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HIGHLIGHTS

- System balancing needs for deep decarbonization are dependent on technology mix.
- Solar PV deployment is the main driver of battery storage deployment.
- Concentrating solar power with thermal storage is valuable for its dispatchability.
- Wind exhibits seasonal variation, requiring storage with large energy subcomponent.
- Low-cost solar PV and batteries can mitigate the cost of climate change mitigation.

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ABSTRACT

We explore the operations, balancing requirements, and costs of the Western Electricity Coordinating Council power system under a stringent greenhouse gas emission reduction target. We include sensitivities for technology costs and availability, fuel prices and emissions, and demand profile. Meeting an emissions target of 85% below 1990 levels is feasible across a range of assumptions, but the cost of achieving the goal and the technology mix are uncertain. Deployment of solar photovoltaics is the main driver of storage deployment: the diurnal periodicity of solar energy availability results in opportunities for daily arbitrage that storage technologies with several hours of duration are well suited to provide. Wind output exhibits seasonal variations and requires storage with a large energy subcomponent to avoid curtailment. The combination of low-cost solar technology and advanced battery technology can provide substantial savings through 2050, greatly mitigating the cost of climate change mitigation. Policy goals for storage deployment should be based on the function storage will play on the grid and therefore incorporate both the power rating and duration of the storage system. These goals should be set as part of overall portfolio development, as system flexibility needs will vary with the grid mix.

1. Introduction

Deep decarbonization of the electric power sector, combined with electrification of most end-uses of natural gas and oil, is indispensable to achieving climate change mitigation [1]. Renewable energy technologies such as wind and solar can contribute to electricity decarbonization. However, these resources have variable and uncertain power output. The need to balance them poses operational challenges and increases grid integration costs. A large number of integration studies have been conducted for regions in the United States and Europe, exploring the operational impacts and integration costs of intermittent energy sources [2,3]. These studies assume pre-specified deployment levels and locations of wind and solar power plants and take the rest of the grid as fixed, investigating only a limited number of fleet configurations for generation, transmission, and storage. Here we use a capacity-planning model for the economic evaluation of intermittent renewables and a range of balancing solutions. We include operational detail in an investment-modeling framework to make it possible to evaluate the economics of a range of system flexibility resources. We focus in particular on the need for and role of electricity storage in deeply decarbonized power systems.

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Electricity storage is one way to balance electricity demand and supply in electricity systems with deep penetration levels of wind and solar. Modeling the costs and benefits of storage technologies has generally taken one of two approaches: (1) use of market price data to determine the revenue that would be available to a storage project [4–7] or (2) use of production cost simulation models of the system with and without storage to determine how the availability of storage affects system operational costs [8,9].

A weakness of the first approach is that storage participation in the energy market will affect market prices by increasing demand during times when the storage is charging, thus raising the market price, and increasing supply during times when the storage is discharging, thus lowering the price. Pre-determined market prices therefore provide a reasonable approximation for the revenue stream available to the marginal storage unit, but become increasingly inaccurate as additional storage is added to the fleet or other components of the system are changed.

The second approach explores the difference in operational costs between systems with and without storage. A weakness of this approach is that it does not directly consider capital costs and potential savings from avoided investment in non-storage infrastructure. After the production cost model is run, the operational cost savings provided by storage may be compared to its capital cost to determine whether the benefit to the system would justify investment in storage. However, the rest of the system is held as fixed, so this approach does not provide information on how other generation and transmission infrastructure should be deployed and how the grid should be developed to minimize system cost as demand, technologies, and policies change. Most storage analyses to date do not allow for transmission or other sources of flexibility to be built as an alternative to storage to meet integration requirements, thus not considering the possible trade-offs or synergies among these flexibility options. These interdependencies become increasingly important as more variable renewable energy is deployed.

Capacity-planning models like SWITCH [10,11] and the Renewable Energy Deployment System (ReEDS) [12,13] offer an additional approach to examining the role of storage in grids with low levels of greenhouse gas (GHG) emissions. Their purpose is to explore how total system cost (capital, fixed, and variable costs) can be minimized, and to co-optimize storage deployment and investment in other system infrastructure. As intermittent renewable generation achieves higher penetration levels, integration alternatives such as transmission expansion, fast-ramping generation, storage, and demand response ought to be considered and compared in a single framework. We have incorporated operational detail into the SWITCH long-term capacity-planning model to allow for more accurate economic evaluation of intermittent renewables, storage technologies, and other integration alternatives [14,15]. Wind and solar generation technologies have low variable costs but require investment in capital-intensive infrastructure capacity, so employing capacity-expansion models can aid understanding of and planning for the most cost-effective resource combinations as the power system evolves

2. Methods

2.1. Model

We use the SWITCH model to study the synchronous region of the Western Electricity Coordinating Council (WECC). WECC covers eleven western U.S. states, two Canadian provinces, and northern Baja California, Mexico. The model is run as a linear program whose objective function is to minimize the cost of meeting projected electricity demand with existing and new generation, storage, and transmission between present day and a future year of interest. The optimization is subject to planning reserve margin, operating reserves, resource availability, operational, and policy constraints. The WECC is divided into fifty "load zones" between which new transmission can be built. We include geographic detail on the locations of potential future power plants and transmission lines. The optimization decides whether to operate or retire existing grid assets, can install new conventional generation in each load zone, chooses among thousands of possible wind and solar sites, and can build transmission lines between load zones. In order to account for correlations between demand and renewable generation, the model uses time-synchronized hourly load data and site-specific intermittent renewable generation data to determine least-cost investment in and hourly dispatch of generation, transmission, and storage. The results presented here are based on an investment optimization that includes 600 h and on a subsequent dispatch verification that includes 8760 h.

The version of the SWITCH model used here offers detailed treatment of system operations in a long-term capacity-planning model of a large geographic region. For this study, we have implemented a novel two-variable treatment of storage: investment decisions are made endogenously for both the capacity of the power subcomponent of storage (the maximum rate at which energy can be released) and its energy subcomponent (the total amount of energy that can be stored) [16]. The model can therefore determine the optimal size of storage devices for a given cost structure, as many types of energy storage technologies exist with different power ratings and discharge times [17–19]. This treatment of storage is an enhancement over our prior work as well as over other capacity-expansion and production cost simulation models, in which the sizing of electricity storage is a model input rather than an endogenous variable. We have also implemented the ability to determine how to optimally release energy from concentrating solar power (CSP) with thermal energy storage (TES) as an endogenous variable in the SWITCH investment optimization. The complete model formulation is available in the Supplementary Material.

2.2. Data and scenarios

We use SWITCH to explore the effect of various sources of uncertainty on storage deployment and overall system development between present day and 2050 in the WECC under strict decarbonization constraints. No scenario is intended as a forecast of future system development: conclusions are based on comparisons across scenarios that point to drivers of system dynamics and the relative importance of different sources of uncertainty.

In all scenarios, the power system achieves GHG emissions levels of 85% below 1990 emissions by 2050. We assume a single GHG target for the whole WECC region. Our goal is to understand the flexibility requirements – and in particular the role of storage – in such systems. In the *Reference* scenario, we assume that neither nuclear plants nor fossil fuel plants with carbon capture and sequestration (CCS) will be built through 2050. The focus is on systems in which low-GHG baseload technologies are not available and intermittent renewable technologies are the main source of GHG-free electricity. Biomass fuel is assumed not to be available to the electricity sector but is instead used for transportation purposes [20,21] further limiting the availability of carbon-free baseload. The potential for bio energy carbon capture and sequestration (BECCS) and negative emissions from such plants [22] is not explored here. Very little technological progress is assumed and costs for most technologies are modeled as constant between present day and 2050. Exceptions include decreases in the capital cost of solar PV, concentrated solar power (CSP), and batteries, but these reductions are modest.

We also investigate a range of sensitivities (Table 1) including (1) the cost of solar technologies, (2) the cost and efficiency of batteries, (3) the price of and emissions from natural gas, (4) the availability of nuclear power and carbon capture and sequestration (CCS), (5) the cost and availability of system flexibility options such as transmission, hydropower, and demand response, and (6) the implementation of efficiency measures.

Hourly load profiles are based on historical data from FERC Form 714 and are modified in future years to introduce bottom–up estimates of the effect of energy efficiency measures, vehicle electrification, and heating electrification as described in [14]. The implementation of efficiency measure and the addition of demand from electric vehicles and heating drive large changes to the demand profile, notably a shift in the timing of the peak in load from the summer afternoons today to the early winter mornings by 2050. The hourly wind output is derived from the 3TIER wind power output dataset developed for the Western Wind and Solar Integration Study [23]. Hourly solar capacity factors are simulated with the NREL System Advisor Model [24]; weather input data were obtained from NREL's Solar Prospector dataset [25].

Reference scenario technology costs are based on estimates and projections from Black and Veatch [26]. The Reference price of natural gas is based on the Reference Case of the U.S. Energy Information Administration's Annual Energy Outlook (US EIA AEO) 2012 [27]. The high natural gas price is based on the Low Estimated Ultimate Recovery Case of the US EIA AEO 2012. The Department of Energy's (DOE) sunshot target for solar technologies is to reach \$1.1/W (\$2014) for utility-scale solar photovoltaics (PV) by 2020.

Table 1
Summary of scenarios. All costs are in \$2014.

Input parameter	*Reference* scenario	Sensitivity
Generation	New nuclear excluded (existing nuclear given option to run) Carbon capture and sequestration (CCS) excluded	*Nuclear*: construction of CCS and new nuclear allowed
	Hydropower at 2004–2011 average generation levels	*Limited Hydro*: limit hydro energy availability to 50% of historical levels by 2050
	Solar costs as projected by Black & Veatch (central PV: ~\$2.7/W by 2020 and ~\$2.2/W by 2050; CSP with 6 h storage: ~\$6.5/W by 2020 and ~\$4.9/W by 2050)	*SunShot*: SunShot solar costs (central PV: ~\$1.1/W by 2020; CSP with 6 h storage: ~\$3.3/W by 2020)
Storage	Battery costs as projected by Black & Veatch (~550/kW h in 2020, \$440/kW h in 2050 for total system cost)	*Low-Cost Battery*: battery costs at ARPA-E targets in 2020 (~110/kW h for total system cost)
	Battery round-trip efficiency at 75%	*High-Efficiency Battery*: battery round-trip efficiency at 90%
Natural gas	Price from EIA NEMS Annual Energy Outlook Base Case 2012 (~\$4.4/MMBtu in 2020, ~\$8.8/MMBtu in 2050)	*High-Price Natural Gas*: double *Reference* price
	No methane leakage	*Methane Leakage*: methane leakage at 4%
Demand profile	Electrification of heating and vehicles Technical potential energy efficiency	*Limited efficiency*: efficiency measures not implemented
Demand response	Disabled	*Load-Shifting*: enable load-shifting for thermal loads *Flexible EV Charging*: enable flexible charging of EVs
Transmission	Base cost of ~\$1200/MW-km (before terrain multipliers)	*High-Cost Transmission*: triple Reference price

Four storage technologies are included in the scenarios presented here: existing pumped hydro can continue operation and new compressed air energy storage (CAES), a hybrid storage and gas turbine technologies, batteries, and TES at CSP plants can be built. Two distinct cost trajectories for batteries are modeled. *Reference* scenario costs are based on cost projections by Black and Veatch [26] and decline slowly between present day and 2050 (from \$1070/kW and \$370/kW h in 2015 to \$870/kW and \$310/kW h in 2050). To explore the effect of strong technological innovation and deep cost-reductions in battery technology, we also run scenarios in which battery costs decline to ~\$500/kW for the power subsystem component and ~50/kW h for the energy subsystem component by 2020. This is equivalent to the DOE battery total system cost target of \$110/kW h (\$2014). For comparison, modeled CAES costs are ~860/kW for the power subsystem component and ~\$20/kW h for the energy subsystem component [28].

3. Results

3.1. Electricity production

Across scenarios, the optimal development of the WECC power system varies little through 2030 but diverges widely in later investment periods depending on scenario assumptions (Fig. 1). Coal, gas, and hydro generation dominate these systems in the near term. Wind provides around 10% of all electricity production in most scenarios, and solar deployment displaces most wind if SunShot costs are achieved. By 2030, natural gas replaces most coal in the fuel mix across scenarios and coal capacity is largely retired. The substitution of coal with gas is a main carbon-reduction strategy through 2030 except in the *Methane Leakage* scenario. Addressing issues such as methane leakage and water contamination should be a priority to determine whether natural gas can play such a large role as a "bridge" fuel. If the price of natural gas is doubled, a build-out of wind and geothermal takes place, reducing the share of natural gas to 30%. Wind deployment reaches 40 GW in the scenarios where solar costs remain at default levels. If SunShot targets are reached, an expansion in solar PV capacity takes place instead and the share of natural gas is also reduced.

Unlike in 2030, doubling the price of natural gas price has only a small impact on the composition of the system in the long term (although costs do increase). While natural gas is valuable to the system as it provides hourly and seasonal generation flexibility, the cap on carbon emissions limits the amount of natural gas that the system can utilize, reducing the share of natural gas to less than 6% of total generation in 2050.

Wind has the largest generation share in that timeframe in the *Reference* scenario: 45%. CSP-TES, which first appears in the generation mix in 2040, is deployed widely by 2050 across scenarios as a result of increased system balancing needs. Although more expensive on a levelized cost basis, it outcompetes PV in the *Reference* scenario due to its dispatchability. If low-cost batteries are available to provide balancing, as in the *Low-Cost Batteries* scenario, PV becomes the dominant solar technology. Its share increases from 10% in the *Reference* scenario to 24% in the *SunShot and Low Cost Batteries* scenario. Similarly, low-cost flexibility in the form of demand response and flexible charging of electric vehicles incentivizes solar PV deployment at the expense of CSP-TES, as it makes it possible to shift the lower-cost PV energy from the middle of the day and avoid curtailment.

If new nuclear is allowed at the relative costs assumed here, the 2050 system is dominated by nuclear generation. A total of 85 GW of nuclear power are deployed by 2050, providing 43% of all electricity produced. Little technological progress is assumed for renewable technologies in this scenario: wind costs stay at

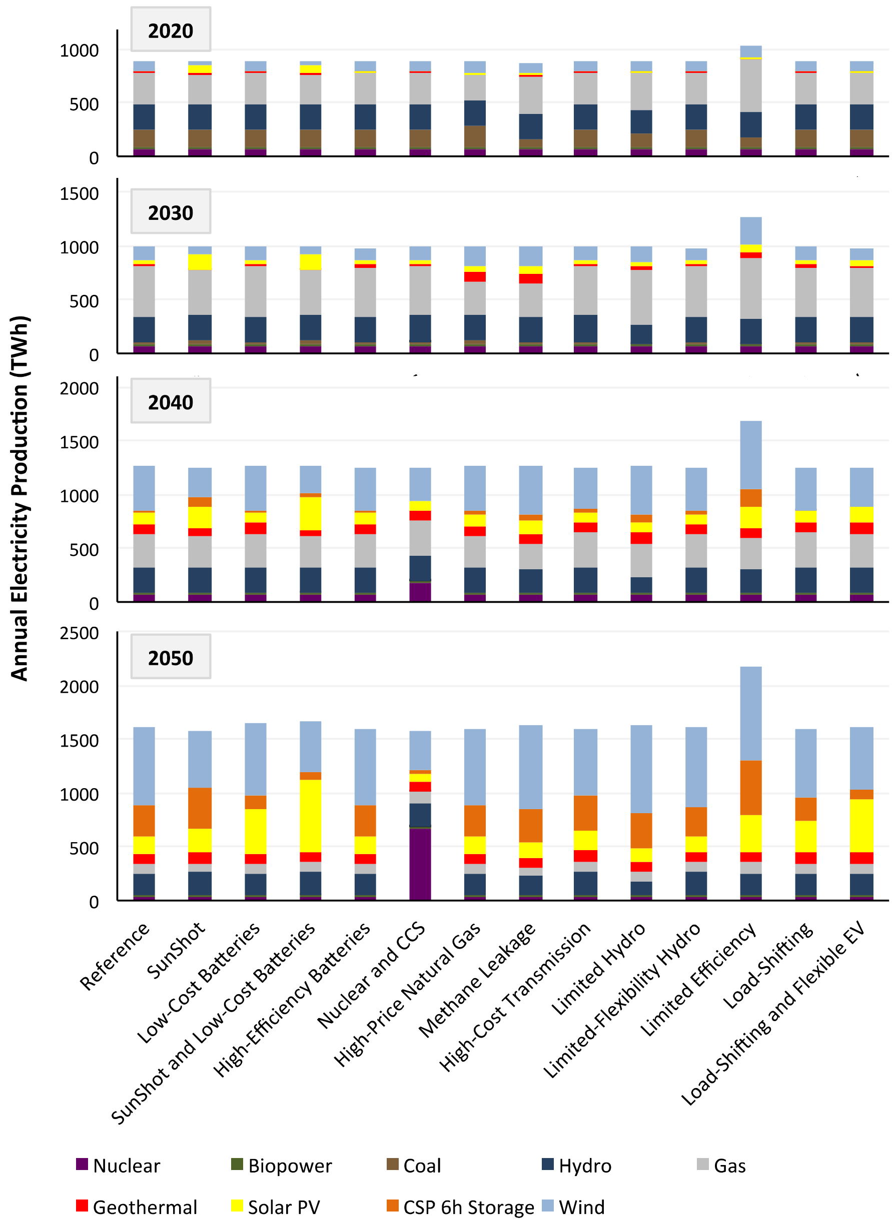

Fig. 1. Electricity production mix in all scenarios in 2030 and 2050.

present-day levels and solar costs decline only slowly through 2050.

The geographic distribution of power generation in the optimized system changes drastically through 2050 (Fig. 2). In 2020, the *Reference* scenario system is similar to the present day power system: generation in the Southwest is dominated by natural gas and complemented by wind and solar deployment; hydropower is dominant in the Pacific Northwest and exported to California; and the eastern part of the WECC relies on coal power complemented by deployment of wind power in the Rockies. By 2030, almost all coal is replaced by natural gas plants and expansion in renewables takes place: solar PV in the Southwest, wind in the Pacific Northwest and eastern WECC. In the 2040 and 2050 timeframes, wind is deployed at scale in the east as well as Alberta and California. Solar PV and CSP-TES are installed in the Desert Southwest, with CSP-TES becoming dominant across the Southwest by 2050. Geothermal potential is tapped out. Transmission flows change considerably from present-day patterns: the largest flows are from east to west, with wind energy in the east being sent to the coastal load centers. Hydropower imports to California via the Pacific DC intertie are minimal.

3.2. Storage deployment

By 2030, cost-effective deployment of new storage begins to take place in most of the scenarios investigated, almost doubling current storage power capacity in some cases. The largest deployment of storage in 2030 occurs in the *SunShot* scenario: 5 GW of CAES with 8-h duration are deployed in the Southwest. Under *Reference* assumptions, CAES costs are lower than batteries' for both the power and energy components. The availability of low-cost batteries results in the substitution of batteries for CAES. The storage is used to provide arbitrage and shift excess solar energy available in the middle of the day to the evening and nighttime hours.

Storage deployment reaches power capacities in the multi-GW scale in most scenarios by 2040 and by 2050 plays a central role in

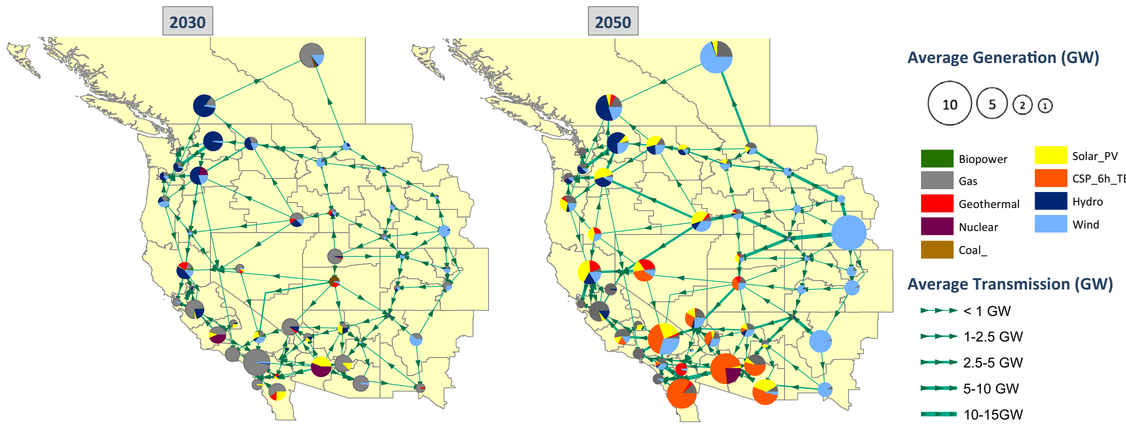

Fig. 2. Maps of average transmission and generation in the *Reference* scenario in 2030 and 2050.

the WECC power system across the scenarios explored here (Fig. 3). However, assumptions about technological costs and availability greatly affect which storage technology is deployed and at what scale in the long-term. Having first appeared in the storage mix in 2040 in the *Reference* scenario, TES deployed at CSP plants is the dominant storage technology in 2050 at the assumed relative costs. Note that TES is different from other storage technologies modeled in that it does not store electricity from the grid but solar thermal energy collected by the CSP plant for later conversion into electricity. In the *Reference* scenario, 120 GW of CSP-TES are installed. In addition, 14 GW of CAES with an average of 10 h of duration and 6 GW of batteries with an average of 2 h duration are deployed to provide arbitrage and reserves. Increasing battery round-trip efficiency from 75% to 90% in the *High-Efficiency Batteries* scenario case does not result in additional deployment of batteries if their costs remain the same as in the *Reference* scenario, suggesting that efficiency alone is not the main driver of battery utilization and cost-effectiveness.

Solar PV with batteries appears to be a main substitute for CSP-TES, with their relative deployment levels dependent on relative costs. The availability of low-cost batteries in 2050 results in their installation at a large scale. In the *Low-Cost Batteries* scenario, 70 GW of batteries are deployed, with an average duration of 6 h. The largest battery deployment occurs in the *SunShot and Low-Cost Batteries* scenario, in which 110 GW of batteries with 6-h duration are installed, mostly in the Desert Southwest where they support large-scale solar PV development.

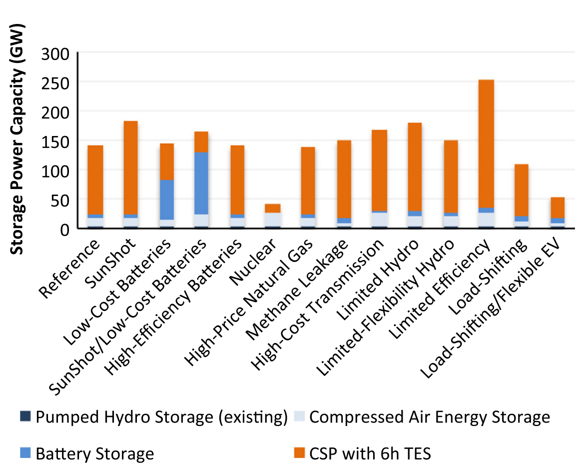

Fig. 3. Storage deployment in 2050 across scenarios.

Limiting the amount of flexibility available to the system as in the *High-Cost Transmission*, *Limited Hydro*, and *Limited-Flexibility Hydro* scenarios results in higher deployment of storage, with CSP-TES remaining dominant at *Reference* costs.

3.3. System operations

The main change in system operations through 2030 is the replacement of baseload coal generation with more flexible natural gas plants that help balance the initial deployment of renewables. Between 2030 and 2050, the dispatch pattern of the *Reference* scenario system experiences drastic changes as a result of growth in total load, changes to the load profile due to efficiency implementation and electrification of heating and vehicles, and a stringent carbon cap that pushes carbon emissions from the system to 85% below 1990 levels. By 2050, the amount of gas in the system is reduced to 6% of total electricity produced because emissions allowances are limited. Expansion in renewables capacity takes place accompanied by a build-out of 20 GW of CAES and battery storage by 2050. Wind dominates in the *Reference* scenario, generating 45% of electricity in 2050, and CSP-TES and solar PV contribute 17% and 10% of energy production respectively. Geothermal generates an additional 6%, providing GHG-free, baseload electricity.

Large seasonal variations in how units are dispatched and load is met become a prominent feature of the 2050 *Reference* system, with wind dominating electricity production in the winter and spring months while CSP-TES and gas help to meet load in the summer (Fig. 4, upper panel). More than 250 GW of wind capacity are installed by 2050 in the *Reference* scenario, and a large amount of wind energy is consistently available in the winter and spring. For example, net load is low and curtailment conditions occur throughout the day for multiple consecutive days in January, so storage is idle: no opportunities to provide arbitrage (i.e. sufficient price differences) exist within the day for extended periods of time, as gas is rarely used. Storage with duration of several days or more, which we do not model here, would be better suited to absorb the excess energy available in January and shift it to other times of the year when prices increase. In the summer months in the *Reference* scenario, wind output is low and the *Reference* system is stressed. In the second half of July, net load reaches its peak summer levels as load is high and wind generation is at its lowest annual capacity factor. In the lowest-cost system designed by SWITCH, peaker gas generation is run throughout the day in the summer in order to meet demand. During this period, the storage deployed in the 2050 *Reference* system is largely idle because combustion turbine (CT) gas plants are on the margin throughout the day and

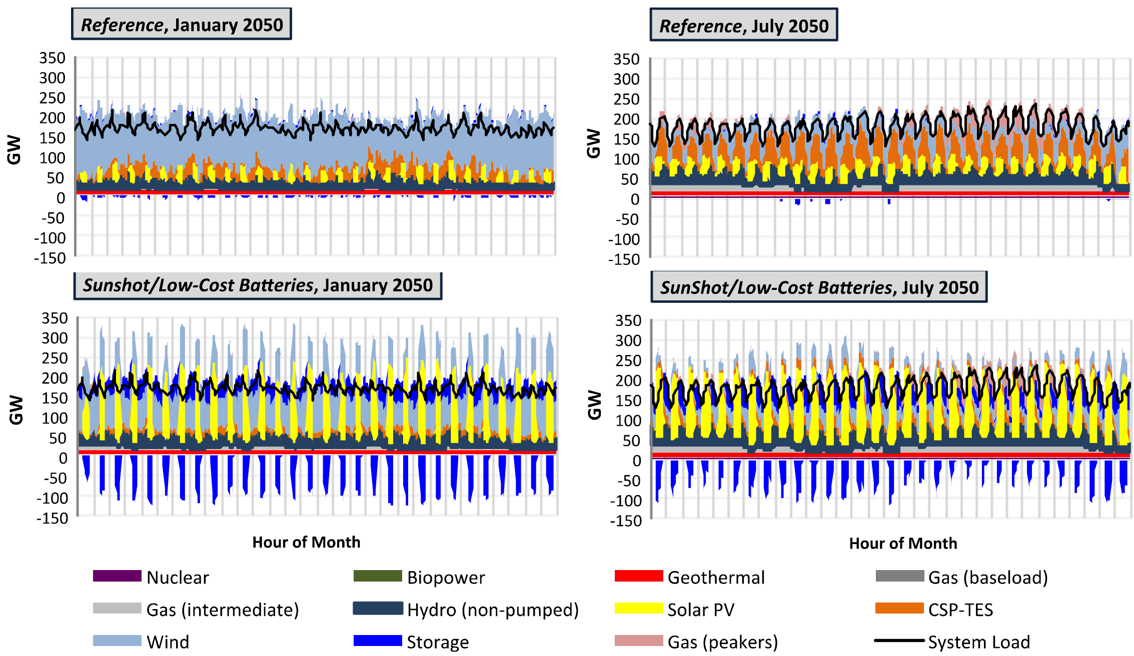

Fig. 4. WECC system hourly dispatch in January and July 2050 in the Reference and SunShot/Low-Cost Batteries scenarios. Vertical lines designate separate days of the month. Total generation is higher than load due to transmission and distribution losses as well as curtailment. When shown as negative, storage is charging.

opportunities for price arbitrage are not available. This result is partly due to the assumption of a uniform CT fleet, but any differences among the heat rates of gas plants would need to be large enough to ensure sufficient revenue from price arbitrage to justify investment in expensive diurnal storage. Longer-duration storage could potentially shift energy from other times of the year to this period of high stress for the grid and replace the gas generation used to meet load in the summer.

The *SunShot and Low-Cost Batteries* scenario has the highest amount of new storage installed in 2050 of all scenarios investigated here. In this case, 110 GW of batteries with an average of 6 h of duration and 20 GW of CAES with an average of 12 h of duration are installed. Both technologies are deployed predominantly in the Desert Southwest – in California, Arizona, and Nevada – to support large-scale solar PV installations.

Relative to the large seasonal variations in the *Reference* case, the dispatch schedule of the *SunShot and Low-Cost Batteries* system is much more similar across seasons and storage is used extensively throughout the year (Fig. 4, lower panel). The typical pattern for storage use is charging in the daytime – when PV is producing electricity, net load is negative, and prices are low – and shifting that energy to other times of the day, including the morning, evening, and night when more expensive generation would otherwise have to be run. This pattern of storage use holds throughout the year. Even during the time of highest system stress when load is at its peak levels and wind output is low in July, excess energy above load is available when PV is producing at full output, net load is negative, and the deployed storage can be used to avoid curtailment and shift the PV energy to other times of the day where it is aided by hydro and gas peaker generation in meeting load. Unlike in the wind-dominated *Reference* scenario, in which the system must address seasonal variations in energy availability from wind and build large amounts of additional thermal generation to ensure that load is met when wind output is low, the *SunShot and Low-Cost Batteries* system relies on solar PV output that is similar across seasons. With the storage technologies modeled here, PV generation can be readily balanced on the daily timescale. Similarly, the sources of demand response modeled in the *Load-Shifting* and *Load-Shifting and Flexible EV Charging* scenarios are inherently a resource that operates within the daily timescale as most commercial and residential thermal end-uses such as heating and cooling as well as charging of EVs can only be shifted a few hours. In that sense, demand response is a resource comparable to storage with duration of several hours. The demand response resource can therefore be matched well to the diurnal cycle of solar PV.

4. Discussion

4.1. The balancing requirements of wind and solar

To further explore the balancing requirements of wind and solar, we run an additional scenario excluding CSP from the optimization and limiting PV deployment to 100 GW (the optimization did not solve at PV levels below 100 GW). In this scenario, a very large amount of wind capacity is installed across the WECC, reaching more than 450 GW by 2050. Even at this very high deployment level of wind capacity, wind energy availability is low in the summer months, requiring the commitment of gas generation – both combined cycle and combustion turbines – to meet high summer load. About 13% of total electricity production is curtailed in the 2050 timeframe in this scenario, largely in the winter when wind output is high. In contrast, only 2% is curtailed in the *SunShot and Low-Cost Batteries* scenario.

The scenarios explored draw from a single year of time-synchronized hourly demand and renewable output data: the historical load profile from 2006 is used to create load projections through 2050, and the wind and solar hourly resource availability data are also based on the 2006 potential in order to account for any temporal correlations between load and renewable output. The hourly wind output is derived from the 3TIER wind power output dataset developed for the Western Wind and Solar Integration Study [23]. Data for two more years – 2004 and 2005 – is available from 3TIER. While there are variations across the three years in the amount of wind energy available during particular times of the year, the seasonal pattern of higher levels of wind generation in the winter months relative to the summer months is in place in all years (Fig. 5). The wind resource in the winter months tends to reach high levels more frequently and fall to low levels less frequently than it does in the summer.

This seasonal pattern in wind output can put stress on the system to meet demand, particularly if the periods of low availability of wind energy coincide with times of high load in the summer. If these conditions last for multiple consecutive days (or an even more extended period of time), other capacity may have to be built and run to compensate, increasing costs and emissions. A large amount of wind energy may need to be stored during other times of the year and shifted to the times of low wind and high load in the summer. Solar PV exhibits less pronounced seasonality than wind. Its output follows the sun's known, cyclical diurnal pattern. Because both load and PV exhibit inherent periodicity and follow a daily pattern that is qualitatively similar across seasons, the net demand that must be met by other energy sources is also periodical. This recurring and predictable diurnal variability of the net load means that the availability of inexpensive storage with several hours of duration can help manage the variability of PV and thus provides a strong incentive for solar PV deployment. By building excess PV capacity above the daily peak load together with storage, the system can predictably shift the excess daytime energy to times when PV output is not available.

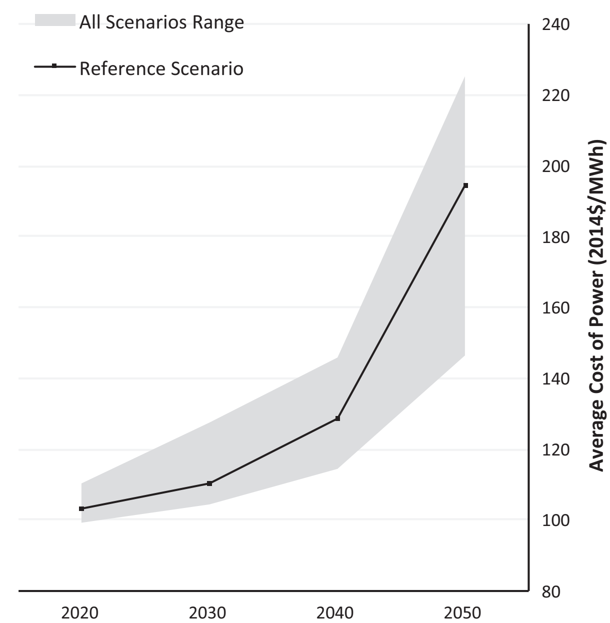

Fig. 6. Average cost of power through 2050 across scenarios.

4.2. The cost of deep electricity decarbonization

Across scenarios, costs rise gradually through 2040 and then increase sharply by 2050 when the system has to meet a stringent carbon cap of 85% below 1990 emissions levels (Fig. 6). Without major technological breakthroughs, the 2050 least-cost power system in the *Reference* scenario has costs much higher than present day, with average cost per MW h produced nearly doubling between 2020 and 2050, even if aggressive levels of energy efficiency are implemented. The average cost of power in 2050 in the *Reference* scenario is \$194/MW h, equivalent to about \$250 billion in annual system costs. Doubling the price of natural gas in the High-Price Natural Gas scenario has a negligible effect on the cost of power in 2050 because the total amount of natural gas that can be used by the system is constrained by the carbon cap. Increasing emissions from natural gas in the Methane Leakage scenario, however, increases costs by 5% in 2050 relative to the *Reference* scenario. The *Limited Hydro* scenario has the most expensive average cost of power in 2050 at \$225/MW h, reflecting the cost of additional deployment of wind and CSP-TES to compensate for the energy deficit resulting from lower hydro output. The *Limited Efficiency* scenario has similar average costs as the *Reference* scenario at \$197/MW h, but a considerably higher total system cost – \$330 billion annually – reflecting the more than 30% increase in total demand if no efficiency measures are implemented.

System flexibility resources – including transmission, CAES, battery storage, and CSP-TES – become a large component of power system cost in 2050. Low-cost flexibility is crucial to cost-containment as the power system is decarbonized. If the price of transmission is tripled, the SWITCH investment optimization responds by increasing deployment of CSP-TES at the expense of wind capacity, which requires long transmission lines that bring the wind resource to load. The availability of low-cost batteries or demand response push the cost of the power system down relative to the *Reference* case to \$185/MW h, \$180/MW h, and \$168/MW h respectively in the *Low-Cost Batteries*, *Load-Shifting*, and *Flexible EV Charging* scenarios, a decrease of 5–14% relative to the *Reference* system. The *SunShot* scenario has even lower costs – \$168/

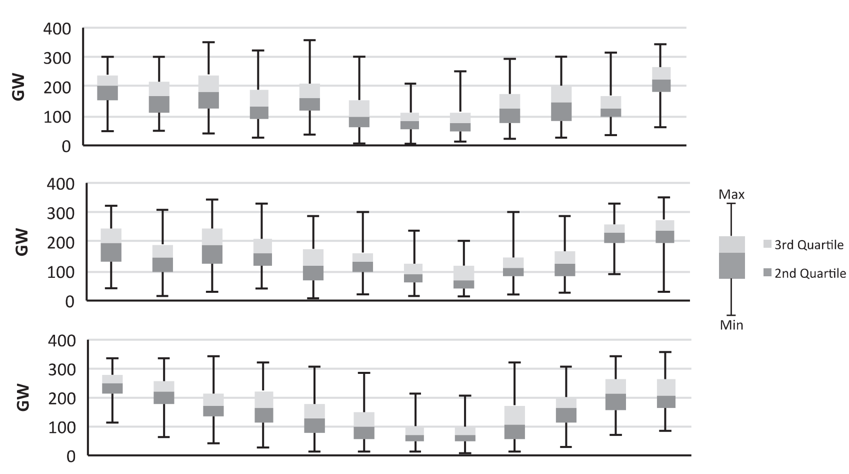

Fig. 5. Box plot of hourly wind output quartiles by month for 2004, 2005, and 2006 based on the 450 GW of wind projects deployed in the No CSP and 100 GW PV Limit scenario.

MW h or about 14% lower than the *Reference* case – largely because reaching the SunShot target makes possible the cost-effective deployment of CSP-TES and reduces the reliance on wind whose seasonality requires supporting gas infrastructure to help meet summer loads. With the assumptions in the *Nuclear* scenario, the cost of power in 2050 is $149/MW h, 23% lower than in the *Reference* case. Cost estimates for nuclear power vary widely and may be lower or higher than modeled here [29]. Nuclear power also faces public acceptance challenges and concerns about safety, nuclear waste disposal, and nuclear proliferation.

The *SunShot and Low-Cost Batteries* scenario has the lowest costs of all scenarios investigated, including the *Nuclear* case. The average cost in this scenario is less than $147/MW h in 2050. The combination of low-cost solar PV and low-cost battery technology, which have a synergetic relationship on the daily timescale, allows SWITCH to design power system that meets aggressive carbon emission reduction targets while greatly containing the cost of decarbonization. Relative to the *Reference* scenario, costs in the *SunShot and Low-Cost Batteries* scenario are 25% lower in 2050 and also provide substantial savings in the near- and mid-term. Cost-effective long-term storage to allow for shifting wind energy across seasons may provide additional avenues for reducing the cost of climate change mitigation in the electricity sector.

5. Conclusion

The results presented here that the main driver of storage build-out in the mid-term is solar PV deployment, which in turn can be driven by a rapid decline in solar costs. Wind and solar PV in the WECC have different balancing requirements for their reliable and cost-effective integration into the power system. A key feature of the WECC wind resource is the large seasonal variation of wind output. At very stringent carbon caps, consistently low wind output in the summer can put high stress on the grid, especially if the wind energy scarcity lasts for multiple days – or even weeks – and coincides with periods of high demand. Storage with a large energy subcomponent would be required to address these energy shortages. Very-long-duration storage such as power to gas is not modeled here, but could be key to reducing electricity sector decarbonization costs. Conversely, solar PV exhibits periodicity over the diurnal timescale and exhibits synergies with storage technologies designed for daily arbitrage. The size of the storage energy subcomponent required to integrate solar PV at a low cost is smaller than that for wind in the WECC.

Considering both the power subcomponent and the energy subcomponent of energy storage – i.e. the timescales over which the storage operates – is important for determining the nature of storage requirements and should be incorporated into policy goals. Storage requirements should be set as part of overall system development goals as different decarbonization pathways have different balancing needs. In planning for low-carbon electricity systems, it is crucial to take a system-wide approach and look for cost-reduction opportunities beyond any single technology or geographic entity as higher levels of intermittent renewable sources are added to the system. Considering technologies in isolation may miss critical synergies and tradeoffs among them. A key next step is to explore the policy, regulatory, and market mechanisms that will provide the appropriate incentives for investment in the most cost-effective portfolio of grid assets.

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Appendix A. Supplementary material

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.apenergy.2015.10.180.

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