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Greenhouse Gas Emission Reductions, System Flexibility Requirements, and Drivers of Storage Deployment in the North American Power System through 2050

by

Ana Mileva

A dissertation submitted in partial satisfaction of the

requirements for the degree of

Doctor of Philosophy

in

Energy and Resources

in the

Graduate Division

of the

University of California, Berkeley

Committee in charge:

Professor Daniel M. Kammen, Chair
Professor Duncan Callaway
Professor Lee Friedman

Spring 2014

Abstract

Greenhouse Gas Emission Reductions, System Flexibility Requirements, and Drivers of Storage Deployment in the North American Power System through 2050

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Doctor of Philosophy in Energy and Resources

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Professor Daniel M. Kammen, Chair

Deep de-carbonization of the electric power sector is indispensable to achieving climate change mitigation. This work explores how aggressive reductions in electricity sector emission levels can be achieved, what the associated costs would be, and how these costs may be minimized. Integrating increased levels of intermittent renewable energy sources into the electricity grid poses new challenges to system planning, operation, and reliability, increasing the need for models that can merge the capabilities of capacity-expansion and production cost simulation models.

I describe the operational detail I have incorporated into the long-term investment framework of the SWITCH model to allow for more accurate evaluation of both the potential contribution of intermittent renewable technologies to electricity decarbonization and the associated system flexibility requirements. I have implemented a series of enhancements to the model's treatment of system operations and generator types – the SWITCH "system flexibility module" – in order to simulate unit commitment as realistically as possible, at an unprecedented resolution for a capacity-expansion model of a large geographic area, offering some of the most detailed treatment to date of day-to-day system operations in an investment model.

I run a range of scenarios to explore the effect of various sources of uncertainty for system development between present day and 2050 in the Western Electricity Coordinating Council (WECC). I include sensitivities for technology costs, fuel prices, technology availability, demand profile, and availability and cost of system flexibility options. I find that meeting a carbon emissions reduction target of 85 percent below 2050 levels is feasible across a range of assumptions. The cost of achieving the goal is highly uncertain, but a number of opportunities to contain costs exist. In the 2030 timeframe, lowering the cost of solar technologies to the SunShot target is the main cost-reduction strategy. Achieving the ARPA-E battery cost target has a small impact on system costs through 2030, as other sources of flexibility are available to the system, including gas generation, hydro, and CAES. The price of natural gas is key to its

utilization in the 2030 timeframe, but is not an important driver in 2050 when natural gas flexibility is of high value yet fuel use is limited by the carbon cap.

Solar PV deployment is the main driver of CAES and battery storage deployment: its diurnal periodicity results in opportunities for daily arbitrage that these technologies are well suited to provide. Storage operation is very different from present day patterns – storage tends to charge during the day when solar PV is available and discharge in the evening and at night. Similarly, the ability to shift loads to the daytime solar peak could have cost-reduction benefits for the system. Wind output exhibits large seasonal variations; because it can remain at very low (or very high) levels for extended periods of time, it does not benefit from CAES and battery storage (operating as providers of daily arbitrage) as much as solar PV does, and instead requires storage with a large energy subcomponent.

CSP with thermal storage is an important component of the 2050 power system, but it directly competes with the combination of solar PV and batteries. If low solar PV costs and low battery costs are achieved, the two technologies may be deployed at large-scale, displacing CSP with thermal storage. The combination of SunShot solar technology and advanced battery technology has the largest impact on total storage capacity deployment in 2050. This combination can provide substantial savings through 2050, greatly mitigating the cost of climate change mitigation and outperforming the nuclear-dominated scenario given the costs assumed here.

Policy goals for storage deployment should incorporate both the power subsystem component and the energy subsystem component of energy storage. In addition, storage deployment requirements should be set as part of overall system development goals as system flexibility needs will vary depending on the rest of the grid mix. Policy ought to be technology-neutral and support a comprehensive portfolio of system flexibility options, allowing flexible generation, demand response, and flexible electric vehicle charging, which can provide comparable services, to compete with storage on a level playing field. The increase in system flexibility requirements can be managed through a system-wide approach including regional cooperation to strategically plan for transmission interconnection and geographic diversity of renewable resource deployment to mitigate the variability of overall output. System-level planning is critical to ensure that appropriate incentives are put in place for all grid assets to fully recover their costs and justify investment while providing the most value to the system and ensuring cost-effective system development over time.

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I would like to thank Matthias Fripp for his groundbreaking work to envision and create the original SWITCH model.

I am deeply grateful to Josiah Johnston and Jimmy Nelson, my colleagues and dear friends, for their extensive contributions to SWITCH and for many conversations that have broadened and deepened my understanding of power systems as well as of the strengths and limitations of modeling. My work has greatly benefited from their constructive feedback, guidance, and insight. I am fortunate to have had their company, friendship, and support during graduate school, making my PhD research a collaborative, fun, and rewarding experience rather than a lonely and isolating endeavor.

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I. Background and Motivation

1. The Role of the Electricity Sector in Climate Change Mitigation

Deep de-carbonization of the electric power sector is indispensable to achieving climate change mitigation. In the United States, the electricity sector accounts for more than 40 percent of greenhouse gas (GHG) emissions ("Emissions of Greenhouse Gases Report" 2008). Recent studies have suggested that in order to meet emission reduction targets of 80 percent below 1990 levels by 2050,[1] many of the end-uses of natural gas and oil would have to be electrified, adding sizable load from electric vehicles and heating ("California's Energy Future: The View to 2050" 2011; Williams et al. 2012). Williams et al. (2012) dub this a transformation from the 'oil economy' to the 'electricity economy,' a revolutionary transition – with the associated changes to the way energy is produced and consumed – that may require substantial modifications to electricity grid planning and operations, technological advancement and cost reductions, transmission expansion, and evolving energy markets.

A key goal of the work presented here is to explore how aggressive reductions in electricity sector emission levels can be achieved, what the associated costs would be, and how these costs may be minimized. A number of low-carbon power generation technologies are available today, including nuclear power, renewable energy sources, and carbon capture and sequestration (CCS). Each option faces challenges, whether it is cost, technical feasibility, or public acceptance. A key question explored here is how low-carbon resources should be optimally combined to leverage synergies among them and achieve emission targets at the lowest possible cost.

Recent trends suggest that renewable energy technologies may make a contribution to power grid de-carbonization. While renewable wind and solar resources are abundant, a main challenge for these technologies is that they are intermittent: their energy output is variable and uncertain, and, as such, less flexible than conventional generation. Integrating increased levels of these renewable energy sources into the electricity grid poses new challenges to system planning, operation, and reliability.

At higher penetration levels, the intermittency of wind and solar presents operational challenges for the grid in making scheduling and dispatch decisions. To date, grid reliability has been maintained, even in areas with the highest renewable generation levels, although various operational issues have been reported, and diverse approaches to effective integration have been put forward (Porter, Yen-Nakafuji, and Morgenstern 2007). Minimizing the cost and reliability impacts of relying on intermittent renewables to expand and de-carbonize the

[1] This target is consistent with the Intergovernmental Panel on Climate Change's (IPCC) 450 parts per million (ppm)

electricity system requires detailed investigation of the evolution of the power system over the time and long-term strategic planning to ensure that the correct operational practices, policies, and market structures and incentives are put in place.

2. Planning Generation and Transmission Capacity for Low-Carbon Grids

The organization of the electricity sector in the United States varies widely from region to region. In general, multiple entities are responsible for the planning of the electricity sector and ensuring the reliable operation of the large and complex grid, and they often coordinate their actions. At a high level, state policies such as renewable portfolio standards and GHG emission targets provide direction for the development of the power system. Regional transmission operators (RTOs) and independent system operators (ISOs) are responsible for planning and approving necessary additions and upgrades to the transmission infrastructure as well for assessing the operational impacts of changes in the generation mix. In the Western Interconnection, the Transmission Expansion Planning Policy Committee (TEPCC) identifies regional transmission system needs for a range of scenarios and coordinates transmission planning and policy. In some states, e.g. California, state-level agencies conduct planning studies forecasting load growth, evaluating the need for new generation and transmission capacity, estimating efficiency savings and demand response potential, and making appropriate policy recommendations and setting procurement goals for utilities.

Under traditional cost-of-service regulation, utilities are responsible for planning and procuring generation resources (which can be utility-owned or acquired through forward contracts or spot market purchases) subject to approval from regulatory agencies. These planning processes usually involve creation of "candidate generation portfolios" based on forecasts for future demand, generation options, fuel prices, and regulatory requirements (Mills and Wiser 2012). The candidate portfolios are compared based on their present values of the revenue requirement (PVRR), comprised of the capital and variable cost of each portfolio. The variable costs are often evaluated using proprietary production cost simulation models[2] and the risk associated with uncertain parameters such as fuel prices or demand forecast is evaluated for each portfolio via scenarios or Monte Carlo analysis. The utilities choose a portfolio that balances costs and risk, and solicit bids for resources consistent with that portfolio during the procurement process.

While production cost simulation models used to evaluate the candidate portfolios are adept at optimizing the day-to-day operations of a given electric power system, they only deal with a *fixed* system and provide little information on how the grid should be developed in the future to minimize cost as demand, technologies, and policies change. Mills and Wiser (2012) note that "[a] number of [load-serving entities] use detailed methods to *evaluate and select* the

[2] Production cost simulation models are security-constraint unit-commitment (SCUC) and security-constrained economic dispatch (SCED) models. Examples include PLEXOS, GridView, and GE Maps.

preferred portfolio from the various candidates, but they [do] not always use such sophisticated methods to *create* candidate portfolios in the first place" (authors' emphasis). The candidate portfolios are created manually or using internal and proprietary capacity-expansion models with limited operational and geographic resolution. These tools typically fail to consider transmission alongside generation and lack the ability to dynamically treat renewable resource integration challenges, e.g. by assuming a fixed contribution that intermittent renewables make to planning reserve regardless of location or overall penetration level (Mai et al. 2013). Furthermore, a limited set of potential portfolios is usually examined.

Traditional capacity-expansion models may have been adequate for planning thermal, fossil-fuel generation, but as long-term grid planning increasingly looks to intermittent generation sources such as solar and wind, the need increases for models that can merge the capabilities of capacity-expansion and production cost simulation models. So far, research has focused on evaluating the costs and operational impacts associated with integrating low to medium levels of intermittent energy sources into the current power system. A large number of integration studies have been conducted for many different regions in the United States and Europe.[3] Notably, the Western Wind and Solar Integration Study (GE Energy 2010) found that it is technically feasible for the existing western U.S. grid to accommodate 30 percent wind and 5 percent solar energy penetration, provided substantial changes to current operating practices. However, these studies investigate a limited range of candidate portfolios: they assume pre-specified deployment levels and locations of intermittent renewables and take the rest of the grid including generation, transmission, and storage as fixed.

Considerable cost-reduction and intermittency-mitigation potential may exist through the optimization of the full generating fleet mix to get to high penetration levels of intermittent renewable generation. Instead of treating the legacy power system as static, the next step should be to plan power systems that are better suited for the flexibility needs of intermittent renewables in order to minimize the cost of integration. It is also crucial to assess how the regional transmission system can be optimized alongside generation by considering balancing possibilities over large regions and the potential ability of neighboring systems to participate in the increased balancing in an economically beneficial way. Models that can incorporate data of high temporal and spatial resolution over large geographic areas need to be developed to plan for coordinated investments and optimize the power system of the future.

[3] See Meibom et al.; GE Energy 2008; "Arizona Public Service Wind Integration Study" 2007; EnerNex Corp 2007; Shiu et al. 2006; EnerNex Corp 2011; "European Wind Integration Study: Final Report"; EnerNex Corp 2006b; "Impact of Wind Power Generation in Ireland on the Operation of Conventional Plant and the Economic Implications" 2004; "Impacts of Large Amounts of Wind Power on Design and Operation of Power Systems, Results of IEA Collaboration" 2009; "Integration of Renewable Resouces: Operational Requirements and Generation Fleet Capability at 20% RPS"; "Integration of Renewable Resouces: Operational Requirements and Generation Fleet Capability at 20% RPS"; GE Energy 2007; GE Energy 2006; "Operational Costs Induced by Fluctuating Wind Power Production in Germany and Scandinavia"; "Operational Impacts of Integrating Wind Generation into Idaho Power's Existing Resource Portfolio" 2007; "Planning of the grid integration of wind energy in Germany onshore and offshore up to the year 2020 (DENA Grid Study)" 2005; Rodriguez-Bobada 2006; GE Energy 2005; Holttinen 2004; GE Energy 2010; EnerNex Corp 2006a.

3. Long-Term Capacity-Expansion Models

A number of models have already been developed to evaluate the effect of technological and policy change in the energy sector. Power system operations must be planned on many different timescales, a range encompassing fifteen orders of magnitude (von Meier 2011). Grid models have traditionally addressed only a limited range of the relevant timescales, exploring the deployment of conventional coal and natural gas plants as well as nuclear power, all of which have predictable and controllable output levels (except for forced outages), thus requiring less operational resolution to plan for. The Energy and Information Administration's *National Energy Modeling System* (NEMS) is an economy-wide model that examines U.S. energy markets with a relatively low geographic resolution (15 regions for electricity markets) and temporal (9 time slices per year) on a long time horizon. MARKAL is another model of the energy system investment that recognizes three seasons (winter, summer, and intermediate) and two diurnal divisions (night and day), resulting in six time slices per investment period (Loulou, Goldstein, and Noble 2004). This level of time resolution, however, is insufficient to study the grid impacts of intermittent renewables.

The *Regional Energy Deployment System* (ReEDS) is a public sector model developed at the National Renewable Energy Laboratory (NREL) specifically to study the electric power sector with high levels of intermittent renewable energy. ReEDS offers a detailed geographic treatment of the U.S. electric grid. It uses a statistical approach to intermittent resource availability, examining 17 weather conditions in each of its 2-year optimizations. DeCarolis and Keith (2006) present a model with detailed temporal resolution – 5 years of hourly wind and load data – but look at only a limited number of wind projects serving load at a single location.

As the temporal relationship between intermittent renewable output and load is key to the value of the resources and geographic dispersion has been shown to considerably smooth load and renewable output variability (Milligan and Kirby 2008), combining spatial diversity *and* temporal detail into a single long-term investment framework is necessary to improve the accuracy of results. This is the goal of my work: I seek to incorporate operational detail into the long-term investment framework of the SWITCH model, which I describe extensively below, to allow for more accurate evaluation of both the potential contribution of intermittent renewable technologies to electricity decarbonization and the associated system flexibility requirements.

4. The SWITCH Model

SWITCH is free and open-access software that can be redistributed and modified under the terms of the GNU General Public License version 3. It was created by Dr. Matthias Fripp for his PhD dissertation and Berkeley's Energy and Resources Group to study the cost of achieving high renewable energy targets in California (Fripp 2008; Fripp 2012), using both existing infrastructure and new generation and transmission. Several researchers, including Josiah Johnston, Dr. James H. Nelson, and myself, have since extended the model to the entire Western Electricity Coordinating Council (WECC), incorporated a number of additional technologies, and enhanced capabilities with the goal of capturing both the impacts of intermittency and the range of system flexibility options that may help mitigate those impacts (Nelson et al. 2012; Wei et al. 2013; Mileva et al. 2013).

Documentation for the original version of the model created by Matthias Fripp can be found at http://switch-model.org. Documentation for the WECC version of the model that has been developed and maintained at the Renewable and Appropriate Energy Laboratory at U.C. Berkeley is available at http://rael.berkeley.edu/switch.

SWITCH attempts to capture the temporal relationship between load and renewable power generation levels – both of which can be driven by weather conditions – by using hourly profiles for each intermittent technology. The goal of the model is to inform power system investment decisions by ensuring that the temporal and spatial relationships between load and generation options are taken into account. My work improves on other capacity-planning tools by incorporating elements of the day-to-day operations of a large, interconnected electric power grid in its investment framework.

The version of the model maintained at the Energy and Resources Group at U.C. Berkeley, referred to here as SWITCH-WECC, encompasses the synchronous region of the Western Electricity Coordinating Council (WECC). WECC includes 11 western U.S. states, Northern Baja Mexico, and the Canadian provinces of British Columbia and Alberta. WECC provides an ideal case to examine system dynamics in a complex, interconnected region with significant greenhouse gas (GHG) emissions and many low-carbon generation resources. In addition, versions of SWITCH for the entire North America as well as China, India, Chile, and Nicaragua are currently in development.

SWITCH-WECC is 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. In SWITCH-WECC, existing transmission and plant-level generators are included and can be either used through the end of their operational lifetimes or retired (existing hydro plants are allowed to run indefinitely into the future). The WECC is divided into fifty "load zones" between which new transmission can be built. The optimization is allowed to install conventional generation in each load zone, and it chooses from thousands of possible wind and solar sites in determining renewable generation deployment. 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.

New capacity can be built at the start of each of several "investment periods." The investment decisions determine the availability of power infrastructure to be dispatched in each "study hour," sampled from a year of hourly load and renewable output data for each period. Investment and dispatch decisions over the entire period of the study are optimized simultaneously. Study hours are initially sub-sampled from the peak and median load day of every month. Every fourth hour is selected, and dispatch decisions are initially made for (4 periods) x (12 months/period) x (2 days/month) x (6 hours/day) = 576 study hours. Increasing temporal resolution is a key modeling goal that can be achieved with enhanced computational resources and/or implementing a decomposition technique.

As the SWITCH-WECC investment optimization uses a limited number of sampled hours over which to dispatch the electric power system, unit-commitment 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. The SWITCH-WECC research team is working on performing the dispatch check with an established security-constrained unit-commitment and economic dispatch model such as PLEXOS.

5. The SWITCH System Flexibility Module

Throughout this manuscript I will use the term "system flexibility" to refer to the ability of the power system to match electricity supply and demand in time and space. The grid can derive flexibility from a wide range of sources, including but not limited to fast-ramping generation, various storage technologies, demand response, and transmission interconnections. On the other hand, incorporating high levels of intermittent renewable energy such as wind and solar into the grid imposes additional flexibility requirements because of the uncertainty and variability in the renewable resource.

In planning electric power systems, taking a system-wide approach can identify key cost-reduction opportunities as geographic diversity reduces the overall variability of both load and intermittent renewable output while larger balancing area size provides more balancing resources (Milligan and Kirby 2008). Balancing area cooperation and interconnection are crucial to realizing those benefits. Transmission extensions and optimizing the use of the transmission, however, are only one possible solution for the challenges posed by intermittency. As variable renewable generation achieves even higher penetration levels, other flexibility alternatives including generation, storage, and demand response must also be considered and compared. As most of the intermittent generation and supporting infrastructure has not been deployed yet, employing an *investment* framework is critical to finding the most cost-effective combinations of low-carbon resources. This is particularly important because many renewable energy technologies have very low variable costs but require investment in capital-intensive infrastructure.

The goal of my work has been to incorporate into a single investment framework the ability to account for both the additional flexibility requirements imposed by intermittency, such as the need for additional reserves and frequent cycling and startups of generation, and the flexibility that can be provided by existing and yet-to-be-deployed technologies. Integrating intermittent renewable energy for deep de-carbonization of the electric power grid requires long-term strategic planning and optimization of the system as a whole in order to contain costs as GHG emissions are reduced. Capacity-expansion modeling can help assess the feasibility of high wind and solar penetration levels as well as the costs associated with integration. However, an enhanced treatment of both the impacts of intermittency and possible mitigating policies and enabling technologies is necessary to accurately reflect the conditions the system is likely to face. My work on the SWITCH model aims to simulate system unit-commitment as realistically as possible, at an unprecedented resolution for a long-term investment model of a large geographic area. Such detailed treatment of system flexibility and dispatch in an investment framework could provide valuable insight into cost-effective system development to meet environmental and policy goals.

6. Model Calibration and Uses

Capacity-expansion models have been used for decades. One way to calibrate the performance of models like SWITCH might be the use the inputs that were available decades ago (e.g. forecasts for load, infrastructure capital costs, and fuel prices) and determine how the systems designed by the model compare to how the system developed in reality. This approach is problematic. First, it is not possible to know whether the system developed optimally: the differences observed between model results and real-world systems could be due to factors other than model accuracy. Furthermore, new information can be gathered about the system that was not available when the modeling exercise was performed and decisions adjusted accordingly. In fact, modeling exercises could the source of information that affects decision-making – the goal of modeling is to inform policy. Most importantly, model calibration along the lines described above is not appropriate as the modeling work presented here does not aim to predict future system development.

SWITCH is not a forecasting tool. I have developed and improved the model with the hope that it could provide guidance to policymakers and system planners. The goal is not to predict how the system will develop over time but to help build intuition about the critical issues facing the power system as it transitions to very low greenhouse gas levels. SWITCH can be used to improve the process of generating candidate portfolios and thus conduct enhanced scenario analysis. My work aims to inform the long-term policymaking and planning process by identifying cost-effective resource portfolios and providing estimates for the cost and technical feasibility of scenarios for deeply decarbonizing the electricity system.

Deriving insight from models like SWITCH requires careful examination of the results. Changing certain input parameters can effect changes to outputs that are expected – for example, lowering the cost of a technology would likely result in higher deployment levels of that technology. Quantification of the magnitude of the effect can provide value, but the main approach I use here is to examine and *explain* what other changes take place as a result. In other words, the model should be used not to provide specific answers but to point to system dynamics and dependencies. In some cases, the effect of varying input parameters may also be counterintuitive. The model may therefore provide novel insight, but fully testing and understanding the drivers of such results to ensure that the model is calibrated correctly is critical.

Results can vary widely across scenarios depending on input assumptions and no scenario is a definitive answer for optimal system development over time. Rather, it is only by comparing scenarios and understanding why they differ that conclusions can be made about the critical drivers of system costs and technological mix. At a high level, my research could help identify ways to lower the costs of emission reductions by pointing to interactions, synergies, and trade-offs among technologies, evaluating alternatives, and identifying the relative importance of different sources of uncertainty. I also explore scenarios with input assumptions that may be considered unrealistic in order to understand the key drivers of system costs and technological deployment decisions. By fully mapping out the parameter space, it may be possible to understand important system dynamics better. Models like SWITCH can point to fruitful directions and critical considerations for system development.

SWITCH, however, is only one available tool. Comparison with other capacity-expansion models – what conclusions are shared across models and where they diverge – may provide further insight into what assumptions drive results. In addition, SWITCH should be used in conjunction with production cost simulation models that test whether the candidate portfolios created can in fact operate reliably. The unit-commitment verification step employed here is meant to increase confidence in the validity of the results. However, neither the main SWITCH optimization nor the verification phase enforces power flow constraints; instead, transmission is treated as a transportation network.[4] N-1 security constraints are also not included. SWITCH can point to important system dynamics but can benefit from comparison and cross-checking with other models. Each model has strengths and its weaknesses. Where not possible to incorporate all timescales and features into a single modeling framework, creating interfaces among the different models can provide valuable insight and help calibrate each model for more accurate results through continuous feedback.

[4] Implementation of Kirchoff's laws in an investment framework introduces computationally intensive nonlinearities. However, a "zonal" (as opposed to the more detailed "nodal") treatment of transmission with DC power flow in most security-constrained unit-commitment and dispatch models likely does not provide a significant improvement in accuracy over a transportation network model.

II. Model Development: SWITCH System Flexibility Module

1. Sets and Indices

The following sets and indices will be using extensively to describe the capabilities of the SWITCH model throughout this document.

Set	***Index***	***Description***
I	*i*	investment periods
M	*m*	months
D	*d*	dates
T	*t*	timepoints (hours)
$T_i \subset T$	-	set of timepoints in investment period *i*
$T_d \subset T$	-	set of timepoints on day *d*
Z	*z*	load zones
TX	(z,z') $z \in Z, z' \in Z$	transmission paths that connect load areas *a* and *a'*
LSE	*lse*	load-serving entities
BA	*ba*	balancing areas
F	*f*	fuels
R⊂F	*r*	RPS-eligible fuels
DC	*dc*	demand category
P	*p*	all generation and storage projects
GP⊂P	*gp*	all generation projects
$GP_a \subset GP$	-	all generation projects in load zone *a*
DP⊂P	*dp*	dispatchable generation projects
IP⊂P	*ip*	intermediate generation projects
FBP⊂P	*fbp*	flexible baseload generation projects
BP⊂P	*bp*	baseload generation projects
CBP⊂BP	*cbp*	cogeneration projects (baseload)
VP⊂P	*vp*	variable renewable generation projects
SP⊂P	*sp*	storage projects (pumped hydro, compressed air energy storage and battery storage)
$SP_z \subset SP$	-	storage projects in load zone *z*
HP⊂P	*hp*	hydroelectric projects
PHP⊂S, HP	*php*	pumped hydroelectric projects
BP⊂S	*bp*	battery storage projects
CP⊂S, DP	*cp*	compressed air energy storage projects
CSP⊂P	*csp*	concentrated solar power projects with six hours of storage
EP⊂P	*ep*	existing plants

Table 1. Sets and Indices Used.

The installation of power systems infrastructure over time is determined by the capacity investment decision variables in SWITCH, including:

- Amount of new generation or storage capacity to install each load zone in each investment period. For compressed air energy storage and battery storage, the model decides both the power capacity of the project and the energy capacity of the project
- Amount of transmission capacity to add between load zones in each investment period
- Amount of existing thermal power plant capacity to keep operational in each investment period
- Amount of distribution network capacity to install in each load zone in each investment period

Investment Variables	**Description**
$G_{p,i}$	Generation or storage power capacity to install at project *p* in investment period *i*
$SE_{sp,i}$	Storage energy capacity to install at storage project *sp* in investment period *i*. Dividing storage power capacity by storage energy capacity gives the duration of the storage project.
$IG_{p,i}$	Derived variable equal to the sum of generation or storage power capacity installed at project *p* through investment period *i* and not yet retired
$ISE_{sp,i}$	Derived variable equal to the sum of storage energy capacity installed at project *p* through investment period *i* and not yet retired
$E_{ep,i}$	Capacity at which to operate existing plant *ep* in investment period *i*
	Transmission capacity to install between two load zones (*z,z'*) in investment period *i*
$D_{z,i}$	Distribution network capacity to install in load zone *z* in investment period *i*

Table 2. Investment Variables.

Generation and storage projects can only be built if there is sufficient time to build the project between present-day and the start of each investment period. This is important for projects with long construction times such as nuclear plants and compressed air energy storage projects, which could not be finished by 2016, even if construction began today. Carbon capture and sequestration (CCS) generation cannot be built in the first investment period of 2016-2025, as this technology is not likely to be mature enough to able to be deployed at large scale before 2020. The installed capacity of resource-constrained generation and storage projects cannot exceed the maximum available resource for each project.

During each investment period, the model decides whether to operate or retire each of ~730 existing thermal power plants in WECC. Once retired, existing plants cannot be re-started. All existing plants are forced to retire at the end of their operational lifetime except for hydroelectric facilities. Hydroelectric facilities are required to operate throughout the whole study as, in addition to their value as electric generators, they also have other important functions such as controlling stream flow. Existing wind plants are required to operate until the end of their operational lifetime. Existing solar plants are not modeled.

New high-voltage transmission capacity is built along existing transmission corridors between the largest capacity substations of each load zone. Transmission can be built between adjacent load zones, non-adjacent load zones with primary substations less than 300 km from one another, and non-adjacent load zones that are already connected by existing transmission. Transmission capacity cannot be retired in the current version of SWITCH.

Investment in new distribution capacity within a load zone is included as a sunk cost equal to the cost of building the distribution system to meet projected peak demand. By default new distribution capacity does not therefore have associated decision variables. However, if demand response is enabled, investment in new distribution capacity may take place to enable load shifting to peak demand hours – peak demand hours may coincide with hours of low net demand, e.g. when a large amount of solar power is installed that exhibits a positive correlation with demand. In those cases, demand response may shift load from hours just following sunset that have peak net demand to hours early in the day.

The way in which physical power systems infrastructure is utilized to meet demand and other reliability, operational, and policy constraints is determined by unit-commitment decision variables:

- Amount of energy output from each dispatchable and intermediate generation project (hydroelectric and non-cogen natural gas plants) in each hour
- Amount of capacity to commit from each intermediate generation project (non-cogen combined cycle and steam turbine natural gas plants) in each hour
- Amount of capacity to commit to providing operating reserves (spinning and quickstart capacity) from dispatchable and intermediate generation, as well as storage facilities, in each hour
- Amount of energy to generate from each flexible baseload generation project (coal plants) each day
- Amount of energy to transfer along each transmission corridor in each hour
- Amount of energy to store and release at each storage facility (pumped hydroelectric, compressed air energy storage, and sodium-sulfur battery plants) in each hour
- If demand response is enabled, the amount of demand to shift from and to each hour

Unit-commitment decisions are not made for baseload generation projects (nuclear, geothermal, biomass, biogas, bioliquid) because these generators, if active in an investment period, are assumed to produce the same amount of power in each hour of that period. Unit-commitment decisions are also not made for variable renewable generators such as wind and solar. If the model chooses to install them, wind, solar photovoltaic (PV), and concentrating solar power (CSP) (without storage) facilities produce an amount of power that is exogenously calculated: a capacity factor is specified for each hour based on the weather conditions in the corresponding historical hour at the location of each renewable plant. Excess generation can be produced at any time and is curtailed.

Unit-Commitment Variables	**Description**
$O_{p,t}$	Energy output of project *p* in hour *t*
$C_{ip,t}$	Capacity committed from intermediate generation project *ip* in hour *t*
$ST_{ip,t}$	Capacity of intermediate generation project *ip* started up in hour *t* since the previous hour
$C_{fbp,d}$	Capacity committed from flexible baseload project *fbp* on day *d*
$TR_{(z,z'),t}$	Energy transferred in hour *t* along the transmission path between two load zones (*z,z'*)
$S_{sp,t}$	Energy stored in hour *t* at storage project *sp*
$R_{sp,t}$	Energy released in hour *t* from storage project *sp*
$ES_{sp,t}$	Energy available in hour *t* at storage project *sp*
$SR_{p,t}$	Spinning reserve provided by dispatchable or intermediate project *p* in hour *t* (*p*∈DP*U*IP)
$Q_{p,t}$	Quickstart reserve provided by project *p* in hour *t* (*p*∈DP*U*IP)
$OP_{p,t}$	Operating reserve (spinning and quickstart) provided by hydroelectric or storage plant *p* in hour *t* (*p*∈HP*U*SP)
$OCSP_{z,t}$	Direct energy output from CSP plants with storage in load zone *z* in hour *t* (energy has not been stored)
$SCSP_{z,t}$	Energy stored in hour *t* by CSP plants with storage in load zone *z*
$RCSP_{z,t}$	Energy released from storage in hour *t* by CSP plants with storage in load zone *z*
$TES_{z,t}$	Energy available in hour *t* in CSP thermal energy storage in load zone *z*
$DR_{z,t}$	Shift load away from hour *t* in load zone *z*
$MDR_{z,t}$	Meet shifted load in hour *t* in load zone *z*
$REC_{lse,t}$	Renewable energy certificates consumed in load serving entity *lse* in hour *t*
$NP_{z,t}$	Non-distributed energy consumed in load-satisfying dispatch in load zone *z* in hour *t*
$NPR_{z,t}$	Non-distributed energy consumed in reserve margin scheduling in load zone *z* in hour *t*

Table 3. Unit-Commitment Variables.

2. System Flexibility Requirements and the Impacts of Intermittency

In general, intermittent renewable energy sources cause challenges to the grid that can be classified into the following categories:

1) *Power adequacy and capacity credit*: what is the contribution of variable and uncertain renewable generation to ensuring that sufficient generation is available during peak load times or other high-risk system events?
2) *System balancing*: how does the additional variability introduced by wind and solar generation affect the system reserve and ramping requirements on various time-scales?
3) *Grid stability*: how does the introduction of large amounts of renewable generation affect grid stability attributes such as system frequency, voltage, reactive power flow, and so on?

I have implemented a series of enhancements to the model's treatment of generator types in order to simulate system operations and unit commitment as realistically as possible, at an unprecedented resolution for a capacity-expansion model of a large geographic area. This work incorporates into SWITCH-WECC many elements of unit-commitment 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.

Eight categories of generators are operated in SWITCH-WECC:

1) baseload generators, which run at full output at all times and include nuclear, geothermal, and cogeneration plants;
2) flexible baseload 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 (see Section 2.3.2);
3) intermediate generators such as 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 (see Section 2.3.3);
4) peaker gas combustion turbines, which incur startup costs but have flexible output restricted only by installed capacity (see Section 2.3.4);
5) storage plants, including battery storage and compressed air energy storage (CAES), which operate subject to daily energy balance constraints (see Section 3.1);
6) hydropower plants, which are dispatched within water availability and minimum flow limits (see Section 3.4);
7) intermittent plants, which have a pre-specified output based on historical data;
8) hybrid intermittent-storage plants, including concentrating solar power (CSP) plants with storage, which have a pre-specified schedule for energy input from the solar field and can either directly release that energy or store it for later use, subject to energy balance constraints (see Section 3.2).

In addition to a linearized representation of the relative maneuverability of generation and storage assets, I have developed the capability to model shiftable loads in SWITCH-WECC, allowing the model to assess the value of system flexibility derived from loads (see Section 3.3). Many of the novel enhancements to SWITCH-WECC have also been incorporated into version for the model for other regions currently under development, including SWITCH-China, SWITCH-Chile, and SWITCH-India, among others.

The ability to model both the impacts of intermittency (such as the need for additional capacity and operating reserves, more frequent cycling and startups of generation, and heat rate penalties) and the various system flexibility resources that could mitigate those impacts allows SWITCH to more accurately evaluate the costs of electricity de-carbonization with intermittent renewable resources and to point to ways to contain those costs.

2.1. Power Adequacy and Capacity Credit

Electrical systems have traditionally been designed to balance two main sources of uncertainty: customer demand and the availability of generators, which experience differing probabilities of mechanical and electrical failures, i.e. forced outages (Milligan and Porter 2008). A planning reserve must therefore be maintained in excess of load requirements to maintain reliability. One approach is to have a fixed level of planning reserves, e.g. installed generation fleet capacity 15 percent above the expected load, but this approach does not take into account generator forced outage rates, which may differ significantly from system to system, nor does it quantify the frequency of system outages. Another method is to consider loads, generation capacity, and forced outage rates to arrive at a loss of load probability (LOLP) for each day and at the corresponding annual measure: the loss of load expectation (LOLE). A commonly used reliability target is 1 day per 10 years outage rate, which is equivalent to a probability of 0.9997 that generation will be sufficient to meet load on a given day (LOLP = 0.0003) without the need for imports. In the United States, capacity requirements currently vary from region to region, although the North American Electric Reliability Corporation (NERC) is developing consistent requirements for adequacy assessment (Milligan and Porter 2008; “2008 Long-Term Reliability Assessment, 2008-2017” 2008).

Because renewable power output is intermittent – both variable and uncertain – at high renewable penetration levels it is important to consider the amount of power in the system that is likely to be available during peak load periods. A commonly used measure of a power plant’s contribution toward system reliability is its capacity value or effective load-carrying capability (ELCC). Other approaches such as exceedance methodologies have also been implemented. The 70 Percent Exceedance methodology currently used by the CPUC to determine resource adequacy is an example of this method (CPUC 2009). Plants that can consistently deliver power during periods of high demand have a high ELCC. For a conventional power plant that has a relatively low probability of failure (low forced outage rate), the ELCC value will usually be a large percentage of the power plant’s rated capacity and can often be approximated simply by *(1-r)*C* where *C* is the rated capacity and *r* is the forced outage rate. Similarly, with renewable energy generation, the goal is to determine the capacity value for wind and solar power relative to a perfectly reliable generating unit, or preferably, because such a unit does not exist, to a benchmark unit such as a gas plant with an outage rate of five percent (Milligan and Porter 2008).

In SWITCH, it is not possible to run a stochastic simulation to evaluate the LOLP of the system or the ELCC of generators. To account for outages, the capacity of all generator, storage, and transmission projects is de-rated by their outage rates for the purposes of satisfying load. A simple approach is used of holding a planning reserve margin of 15 percent above load in every load zone in every timepoint. Intermittent renewable generators can contribute to the planning reserve margin an amount equal to their capacity factor in that hour times their capacity. This approach has a number of limitations. Among them is that the sampling method used to create a training set of timepoints over which to commit the power systems created by the SWITCH investment optimization may miss the times of highest grid stress. As a result, the system created by SWITCH may experience outages when tested on a larger test set of timepoints.

Increasing the temporal resolution of the investment optimization is one way to address this problem, as it would make it more likely that the critical periods for the grid are included and accounted for. However, this approach is currently not feasible due to computational constraints. Instead, I address this problem through an iterative method of 1) running the SWITCH investment optimization, 2) testing the system designed by the model on a larger set of timepoints, and 3) including the timepoints with the highest capacity shortfalls from step 2 into the main optimization, then returning to step 1. I repeat the process until all capacity shortfalls are eliminated. This approach of finding the times of highest grid stress – the peak net load hours – was first implemented in Mileva et al. 2013 and ensures that those time are accounted for by the SWITCH investment optimization in designing the power system.

2.2. Operating Reserves

2.2.1. Reserve Requirements

Operating reserves in the WECC are currently determined by the "Regional Reliability Standard to Address the Operating Reserve Requirement of the Western Interconnection" ("WECC Standard BAL-STD-0020 - Operating Reserves" 2007). This standard dictates that operating reserves (spinning and quickstart) must be at least: "the sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation." At least half of those reserves must be spinning, i.e. online and synchronized to the grid but backed off from full output. In practice, this NERC standard has usually meant a spinning reserve requirement of 3 percent of load and a quickstart reserve requirement of 3 percent of load.

Similarly, the WECC version of SWITCH holds a base operating reserve requirement of 6 percent of load in each study hour, half of which is spinning. In addition, “variability” reserves: spinning and quickstart reserves each equal to 5 percent of the wind and solar output in each hour are held to cover the additional uncertainty imposed by generation variability at the subhourly timescale. These default requirement levels can be readily varied.

The default operating reserve requirement is based on the “3+5 rule” developed in the Western Wind and Solar Integration Study as one possible heuristic for determining reserve requirements that is “usable” to system operators (GE Energy 2010). The 3+5 rule means that spinning reserves equal to 3 percent of load and 5 percent of wind generation are held. When keeping this amount of reserves, the report found, at the study footprint level there were no conditions under which insufficient reserves were carried to meet the implied $3\Delta\sigma$ requirement for net load variability.[5] For most conditions, a considerably higher amount of reserves were carried than necessary to meet the $3\Delta\sigma$ requirement. Performance did vary at the individual area level, so in the future customized reserve rules may be implemented for different areas.

SWITCH’s operating reserve requirement is more stringent, as quickstart reserves of 3 percent of load and 5 percent of variable renewable generation are also held in addition to spinning reserves. We assume that solar generation, with the exception of CSP with 6 hours of storage, which exhibits little 10-min variability, impose reserve requirements similar to wind's (i.e. 5 percent of generation). Solar CSP without storage contributes only to the quickstart requirement.

2.2.2. Balancing Area Size

The size of the entity responsible for providing balancing services is important both in terms of ability to meet the reserve requirement and the cost of doing so. The sharing of generation resources, load, and reserves through interconnection and market mechanisms is one of the least-cost methods for dealing with load variability. Multiple renewable integration studies have now also demonstrated the benefits of increased balancing area size (through consolidation or cooperation) in managing the variability of variable renewable output. At present, WECC operates as 39 balancing areas (GE Energy 2010), but in light of the large benefits of increased balancing area size, their functions will likely be consolidated in the future. The Western Wind and Solar Integration Study assumes five regional balancing area in WECC for operating reserves – Arizona-New Mexico, Rocky Mountain, Pacific Northwest, Canada, and California – as their “statistical analysis showed, incorporating large amounts of variable renewable generation without consolidation of the smaller balancing areas in either a real or virtual sense could be difficult.” Similarly, the WECC version of SWITCH assumes the

[5] The statistical technique of combining the variability of VERs with load variations to arrive at the net load variability on various timescales – and corresponding balancing needs – is often referred to as the “$3\Delta\sigma$ method.” Three times the standard deviation (σ) of the distribution of the deltas (Δ), i.e. the differences in net load from one point in time to the next (e.g. every 10 minutes), is taken as the confidence level for how much of the variations should be covered by reserves. Three standard deviations covers about 99.7 percent of the observed variations (Milligan 2003).

primary NERC subregion as the balancing area in its optimization by default. Six balancing areas are modeled: Arizona-New Mexico, Rocky Mountain, California, Pacific Northwest, Canada, and Baja California. The balancing area size can be varied.

2.2.3. Provision of Spinning Reserves

The current implementation of operating reserves in SWITCH-WECC allows natural gas generators (including gas combustion turbines, combined-cycle natural gas plants, and steam turbine natural gas plants), hydro projects, and storage projects (including compressed air energy storage, batteries, and pumped hydro) to provide operating reserves. Coal plants and concentrated solar power plants with thermal storage do not provide operating reserves in the model.

It is assumed that natural gas generators back off from full load and operate with their valves partially closed when providing spinning reserves, so they incur a heat rate penalty. The spinning reserve heat rate penalty is calculated from the generator's part-load efficiency curve shown in Table 4 (London Economics and Global Energy Decisions 2007).

	25%	***50%***	***75%***	***100%***
Combined Cycle Gas Turbine (CCGT)	1.788	1.195	1.102	1
Gas Steam Turbine	1.276	1.061	1.01	1
Gas Combustion Turbine	1.504	1.095	1.029	1

Table 4. Heat rate degradation below full load relative to the full load heat rate by gas turbine technology

The method for calculating the spinning reserve heat rate penalty factor (*spin_heat_rate_penalty*) is further described below. Variables used are capitalized and parameter names are in lower case.

The fuel use of a plant is equal to the output of the plant times the heat rate at that loading level. When backed off from full load and providing spinning reserves is equal to the output of the plant times the degraded below-full-load heat rate:

$$Fuel\_Use(Power\_Output) = Power\_Output \times heat\_rate(Power\_Output)$$

Loading is defined as the ratio of plant output and plant capacity (*Loading=Power_Output/capacity*), so this is equivalent to:

$$Fuel\_Use(Power\_Output) = Power\_Output \times heat\_rate(Loading)$$

In SWITCH, the heat rate degradation is represented by applying a penalty term when the plant is providing spinning reserves:

$$
\begin{aligned}
&Fuel\_Use(Power\_Output) \\
&\qquad = Power\_Output \times heat\_rate(full\_load) \\
&\qquad + Spinning\_Reserve \times spin\_heat\_rate\_penalty(Loading) \\
&\qquad \times heat\_rate(full\_load)
\end{aligned}
$$

Combining the two equations above, we get:

$$
\begin{aligned}
&Power\_Output \times heat\_rate(full\_load) \\
&\qquad + Spinning\_Reserve \times spin\_heat\_rate\_penalty(Loading) \\
&\qquad \times heat\_rate(full\_load) = Power\_Output \times heat\_rate(Loading)
\end{aligned}
$$

Assuming that the sum of the energy output and spinning reserves is equal to the installed capacity and dividing by installed capacity, this gives:

$$
\begin{aligned}
&[(Power\_Output \times heat\_rate(full\_load) + (capacity \\
&\qquad - Power\_Output) \times spin\_heat\_rate\_penalty(Loading) \\
&\qquad \times heat\_rate(full\_load))]/capacity \\
&\qquad = (Power\_Output \times heat\_rate(Loading))/capacity
\end{aligned}
$$

Finally, we express the spinning reserve heat rate penalty as a function of loading:

$$
\begin{aligned}
&spin\_heat\_rate\_penalty(Loading) \\
&\qquad = \frac{Loading \times (heat\_rate(Loading) - heat\_rate(full\_load))}{(1 - Loading) \times heat\_rate(full\_load)}
\end{aligned}
$$

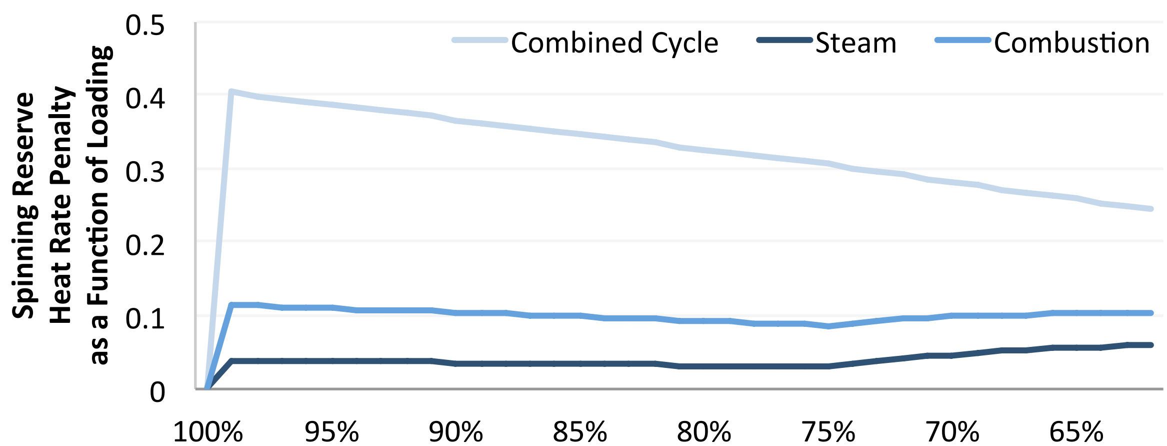


Figure 1. Spinning reserve heat rate penalty as a function of loading by turbine technology.

The *spin_heat_rate_penalty* parameter input into SWITCH-WECC is calculated as the average penalty between full loading and the loading level of full load minus each gas turbine technology's 10-minute ramp rate. Ramp rates are from the Western Wind and Solar Integration Study and are shown in Table 5 (GE Energy 2010). We assume that a combustion turbine will never run at part load lower than 50 percent, so the 10-min ramp rate used to calculate the spinning reserve heat rate penalty is 0.5 rather than 1.

Gas Turbine Technology	1-min Ramp Rate
Combined Cycle	0.038
Steam	0.031
Combustion	0.135

Table 5. Ramp rates by gas turbine technology as a percentage of capacity.

The values for *spin_heat_rate_penalty* input into SWITCH-WECC are shown in Table 6. When plants provide spinning reserves, the additional fuel and carbon costs and additional emissions from heat rate degradation are added to the objective function and carbon cap constraints respectively.

Gas Turbine Technology	*spin_heat_rate_penalty*
Combined Cycle	0.33
Steam	0.04
Combustion	0.1

Table 6. Spinning reserve heat rate penalty values input to SWITCH-WECC.

As spinning reserves must be able to respond within 10 minutes, natural gas generators cannot provide more than their 10-min ramp rates in spinning reserves and must also be delivering useful energy when providing spinning reserves (see *SPINNING_RESERVE_AS_FRACTION_OF_COMMITTED_CAPACITY* constraints below) as backing off too far from full load is uneconomical. Hydro projects are limited to providing no more than 20 percent of their turbine capacity as operating reserves, in recognition of water availability limitations and possible environmental constraints on their ramp rates.

SPINNING_RESERVE_AS_FRACTION_OF_COMMITTED_CAPACITY$_{dp,t}$

$$SP_{dp,t} \geq (10\text{min}\ \_ramp\_rate_{dp} / (1 - 10\text{min}\ \_ramp\_rate_{dp}) \times O_{dp,t}$$

SPINNING_RESERVE_AS_FRACTION_OF_COMMITTED_CAPACITY$_{ip,t}$

$$SP_{ip,t} \leq 10\text{min}\ \_ramp\_rate_{ip} \times C_{ip,}$$

2.2.4. Provision of Quickstart Reserves

Quickstart reserves in SWITCH-WECC can be provided by gas combustion turbines, gas steam turbines, and gas combined cycles turbines as well as storage and hydro projects. The provision of quickstart reserves is limited by the installed capacity of projects as well as the energy output and spinning reserves provided by a project in a given study timepoint.

2.2.5. LP Formulation

In each balancing area *ba* in each hour *t*, the spinning reserve ($SR_{p,t}$) provided by dispatchable (DP_{ba}) and intermediate plants (IP_{ba}), plus the operating reserve ($OP_{p,t}$) provided by storage plants (SP_{ba}) and hydroelectric plants (H_{ba}) must equal or exceed the spinning reserve requirement ($Spinning\_Reserve\_Reqt_{ba,t}$) in that balancing area in that hour. The spinning reserve requirement is a derived variable calculated as a percentage of demand plus a percentage of variable renewable generation in each balancing area in each hour.

$SATISFY\_SPINNING\_RESERVE_{ba,t}$

$$\sum_{p \in DP_{ba} \cup IP_{ba}} SR_{p,t} + \sum_{p \in SP_{ba} \cup HP_{ba}} OP_{p,t} \geq Spinning\_Reserve\_Reqt_{ba,t}$$

In each balancing area *ba* in each hour *t*, the sum of the spinning reserve ($SR_{p,t}$) and quickstart reserve, ($Q_{p,t}$) provided by dispatchable (DP_{ba}) and intermediate plants (IP_{ba}) and the operating reserve ($OP_{p,t}$) provided by storage plants (SP_{ba}) and hydroelectric plants (H_{ba}) must equal or exceed the total operating (spinning plus quickstart) reserve requirement ($Spinning\_Reserve\_Reqt_{ba,t} + Quickstart\_Reserve\_Reqt_{ba,t}$) in that balancing area in that hour.

$SATISFY\_QUICKSTART\_RESERVE_{ba,t}$

$$\sum_{p \in DP_{ba} \cup IP_{ba}} (SR_{p,t} + Q_{p,t}) + \sum_{p \in SP_{ba} \cup HP_{ba}} OP_{p,t} - Spinning\_Reserve\_Reqt_{ba,t} \geq Quickstart\_Reserve\_Reqt_{ba,t}$$

2.3. Cycling of Thermal Generation

2.3.1. Deep-Cycling Heat Rate Penalty Calculation

When operating below full load (deep-cycling), a heat rate penalty is applied for flexible baseload plants (coal steam turbines and coal integrated gasification combined cycle turbines (IGCC)) and intermediate combined cycle gas turbine (CCGT) plants. At times when these generator types are deep-cycled, the additional fuel and carbon cost from heat-rate degradation is added to the objective function. If a carbon cap is enforced, the additional emissions are added to the carbon cap constraint.

The calculation for the deep-cycling penalty is described below and is similar to that for plants providing spinning reserves by backing off from full load. Variables used are capitalized and parameter names are in lower case.

The fuel use of a plant is equal to the output of the plant times the heat rate at that loading level. When backed off from full load, fuel use is equal to the output of the plant times the degraded below-full-load heat rate:

$$Fuel\_Use(Power\_Output) = Power\_Output \times heat\_rate(Power\_Output)$$

Loading is defined as the ratio of plant output and plant capacity (*Loading=Power_Output/capacity*), so this is equivalent to:

$$Fuel\_Use(Power\_Output) = Power\_Output \times heat\_rate(Loading)$$

In SWITCH, the heat rate degradation is represented by applying a penalty term when the plant is deep-cycled:

$$\begin{aligned} Fuel\_Use(Power\_Output) \\ &= Power\_Output \times heat\_rate(full\_load) \\ &+ Deep\_Cycle\_Amount \times deep\_cycle\_heat\_rate\_penalty(Loading) \\ &\times heat\_rate(full\_load) \end{aligned}$$

Combining the two equations above and setting *Deep_Cycle_Amount* = *capacity* – *Power_Output*, we get:

$$\begin{aligned} Power\_Output \times heat\_rate(full\_load) + (capacity \\ &- Power\_Output) \times deep\_cycle\_heat\_rate\_penalty(Loading) \\ &\times heat\_rate(full\_load) = Power\_Output \times heat\_rate(Loading) \end{aligned}$$

Dividing by installed capacity and expressing the deep-cycling heat rate penalty as a function of loading, we get:

$$\begin{aligned} deep\_cycling\_heat\_rate\_penalty(Loading) \\ &= \frac{Loading \times (heat\_rate(Loading) - heat\_rate(full\_load))}{(1 - Loading) \times heat\_rate(full\_load)} \end{aligned}$$

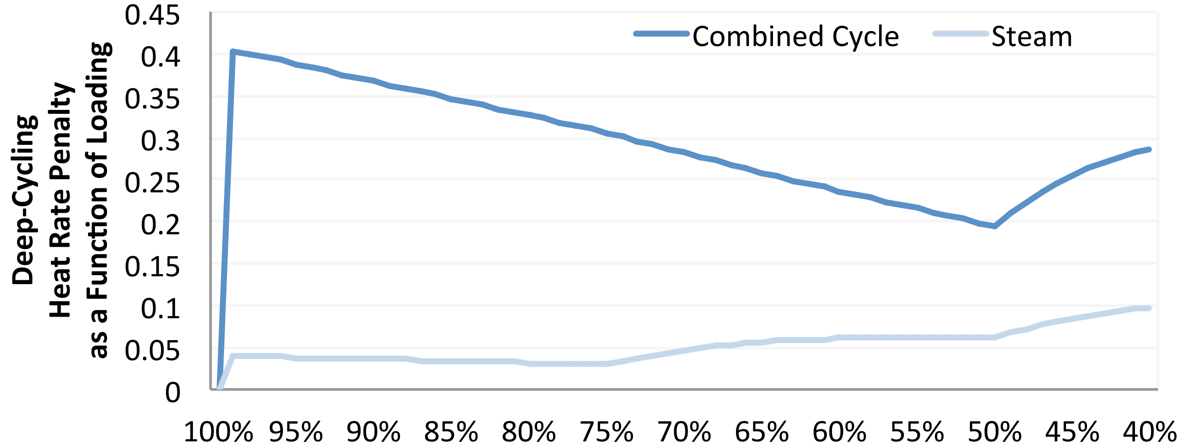


Figure 2. Deep-cycling penalty as a function of load by turbine technology.

The *deep_cycling_heat_rate_penalty* parameter input into SWITCH-WECC is calculated as the average penalty between full loading and the minimum loading level by technology and generator vintage (Table 7. Deep-cycling heat rate penalties input to SWITCH-WECC.).

Gas Turbine Technology	***Minimum Loading***	***Deep Cycling Heat Rate Penalty***
CCGT	0.4	0.33
Coal Steam Turbine (existing)	0.7	0.05
Coal Steam Turbine (new)	0.4	0.04
Coal IGCC	0.4	0.29

Table 7. Deep-cycling heat rate penalties input to SWITCH-WECC.

2.3.2. Part-Load Operation for Flexible-Baseload Coal Plants

Non-cogeneration coal generators in SWITCH-WECC are operated as flexible baseload generators. These generators (the set *FBP*) are assumed to be online throughout their operational lifetime, but can vary output level between a minimum loading level and their nameplate capacity, de-rated by their forced and scheduled outage rates. A minimum loading level is enforced as operating below a certain output level is expensive or technically infeasible, for flexible baseload generators. The operational constraints for flexible baseload generation in SWITCH-WECC are included below.

For each flexible baseload generation project *fbp* on every day *d*, the power output on that day ($O_{fbp,t}$) must be more than the minimum loading fraction for that project ($min\_loading\_frac_{fpp}$) multiplied by the total installed capacity at project *fbp* in period *i* ($IG_{fbp,i}$). The minimum loading fraction is 0.7 for existing flexible baseload coal plants and 0.4 for new flexible baseload coal projects. The forced and scheduled outage rates are designated by for_{fbp} and sor_{fbp} respectively. D_i is the set of days in investment period *i*.

MIN_LOADING$_{fbp,d}$

$$O_{fbp,d\in D_i} \geq min\_loading\_frac_{fbp} \times IG_{fbp,i}$$

MAX_POWER$_{fbp,d}$

$$O_{fbp,\square\in D_i} \leq IG_{fbp,i} \times (1 - for_{fbp}) \times (1 - sor_{fbp})$$

The committed level of output is held constant throughout the day. For each flexible baseload generation project *fbp* in each hour *t* on day d, the power output in that hour ($O_{fbp,t}$) is equal to the power output ($O_{fbp,d}$) committed for that day. T_d is the set of hours on day *d.*

MAX_POWER_HOURLY$_{fbp,t}$

$$O_{fbp,t\in T_d} = O_{fbp,d}$$

2.3.3. Part-Load Operation and Startups for Intermediate Natural Gas Plants

Natural gas combined cycle plants (CCGTs) and natural gas steam turbines in SWITCH-WECC are operated as intermediate generators. They can commit no more capacity to be online in each hour than their nameplate capacity, de-rated by their forced outage rate. Intermediate generation can provide no more power, spinning reserves, and quickstart reserves in each hour than the amount of capacity that was committed to be online in that hour. Spinning reserves cannot exceed a pre-specified fraction of online capacity equal to the generator's 10-minute ramp rate. Combined heat and power natural gas generators (cogenerators) are operated in baseload mode and are not included here.

The formulation of the operational constraints for intermediate generation in SWITCH-WECC is included below.

For each intermediate generation project *ip* in every hour *t*, the capacity committed in that hour ($C_{ip,t}$) cannot exceed the installed capacity at generator *ip* in investment period *i* ($G_{ip,i}$), de-rated by the generator's forced outage rate (o_{ip}). T_i is the set of days in investment period *i*.

MAX_COMMIT$_{ip,t}$

$$C_{ip,t\in T_i} \leq (1 - o_{ip}) \times IG_{ip,i}$$

For each intermediate generation project *ip* in every hour *t*, the power output in that hour ($O_{ip,t}$) must be more than the minimum loading fraction for that project (*min_loading_frac$_{ip}$*) multiplied by total online capacity in that hour ($C_{ip,t}$).

$MIN\_POWER_{ip,t}$

$$O_{ip,t} \geq min\_loading\_frac_{ip} \times C_{ip,t}$$

For each intermediate generation project ip in every hour t, the expected amount of power ($O_{ip,t}$), spinning reserve ($SR_{ip,t}$), and quickstart capacity ($Q_{ip,t}$) supplied by the intermediate generator in that hour cannot exceed the generator capacity committed in that hour ($C_{ip,t}$).

$MAX\_POWER_{ip,t}$

$$O_{ip,t} + SR_{ip,t} + Q_{ip,t} \leq C_{ip,t}$$

For each intermediate generation project ip in every hour t, the spinning reserve supplied by the project in that hour ($SR_{ip,t}$) cannot exceed a pre-specified fraction of online capacity ($spin\_frac_{ip}$). This constraint ensures that spinning reserve is only provided in hours when the plant is online and producing useful generation. The parameter $spin\_frac_{ip}$ is calculated using the generator's 10-minute ramp rate.

$MAX\_SPIN_{ip,t}$

$$SR_{ip,t} \leq spin\_frac_{ip} \times C_{ip,t}$$

For each intermediate project ip in every hour t, the amount of capacity started up ($ST_{ip,t}$) equals the online capacity in timepoint t ($C_{ip,t}$) minus the online capacity in the previous simulated timepoint ($C_{ip,t-1}$). $ST_{ip,t}$ also has to be non-negative by definition, so this constraint is not binding when shutting down generation (i.e. when the difference between online capacity in the current timepoint and the previous timepoint is negative). The implementation is cyclical over the course of a day: the last timepoint of a day is assumed to be the previous timepoint for the first timepoint of that day.

$STARTUP_{ip,t}$

$$ST_{ip,t} \geq C_{ip,t} - C_{ip,t-1}$$

2.3.4. Startups for 'Peaker' Gas Plants

Natural gas combustion turbines are operated as dispatchable generators in SWITCH-WECC. They can provide no more power, spinning reserve, and quickstart capacity in each hour than their nameplate capacity, de-rated by their forced outage rate. Spinning reserve can only be provided in hours when the plant is also producing useful generation and cannot exceed a pre-specified fraction of capacity.

The formulation of the operational constraints for intermediate generation in SWITCH-WECC is included below.

For each dispatchable generation project *dp* in every hour *t*, the amount of power ($O_{dp,t}$), spinning reserve ($SR_{dp,t}$), and quickstart capacity ($Q_{dp,t}$) supplied by the project in that hour cannot exceed the sum of capacity installed at the project *dp* in the current and preceding periods *i* ($G_{dp,i}$), de-rated by the generator's forced outage rate (o_{dp}). T_i is the set of days in investment period *i*.

MAX_POWER$_{dp,t}$

$$O_{dp,t\in T_i} + SR_{dp,t\in T_i} + Q_{dp,t\in T_i} \leq (1 - o_{dp})\times IG_{dp,i}$$

For each dispatchable project *dp* in every hour *t*, the spinning reserve supplied by the dispatchable generator in that hour ($SR_{dp,t}$) cannot exceed a pre-specified fraction ($spin\_frac_{dp}$) of total online capacity ($O_{dp,t} + SR_{dp,t}$). This constraint ties the dispatch of spinning reserve to the amount of power ouput $O_{dp,t}$ to ensure that spinning reserve is only provided in hours when the plant is also producing power.

MAX_SPIN$_{dp,t}$

$$SR_{dp,t} \leq \frac{spin\_frac_{dp}}{(1 - spin\_frac_{dp})}\times O_{dp,t}$$

For each dispatchable project *dp* in every hour *t*, the amount of capacity started up ($ST_{dp,t}$) equals the online capacity in hour t ($O_{dp,t}$ + $SR_{dp,t}$) minus the online capacity in the previous simulated hour ($O_{dp,t-1}$ + $SR_{dp,t-1}$). Hours within each study day are defined circularly (the first hour of the day is preceded by the last hour of the same day) for the purpose of generator startup. $ST_{dp,t}$ also has to be non-negative by definition, so this constraint is not binding when shutting down generation (i.e. when the difference between online capacity in the current timepoint and the previous timepoint is negative). The implementation is cyclical over the course of a day: the last timepoint of a day is assumed to be the previous timepoint for the first timepoint of that day.

STARTUP$_{dp,t}$

$$ST_{dp,t} \geq (O_{dp,t} + SR_{dp,t}) - (O_{dp,t-1} + SR_{dp,t-1})$$

2.4. Ramping of Thermal Generation

The electric power system must maintain the balance between generation and load at any point in time. The amount of load varies continuously and the system must be able to adapt to those changes in order to serve the load reliably. Incorporating intermittent renewable energy sources into the grid adds variability to the net load. Other generation (or storage) must be adjusted constantly to maintain the system frequency as net load varies. Many generators, however, are limited in how fast they can ramp up and down. For example, large baseload plants (particularly nuclear, but also coal) are limited in the rate at which they can vary output and in how much they can vary output. For many plants, reducing production below a minimum load may require a complete shutdown and a lengthy and expensive restart process, and can negatively affect the operating lifetime of a generation asset.

As discussed above, I have included a number of these considerations in SWITCH-WECC as part of the system flexibility module. Baseload generators in SWITCH such as nuclear and geothermal are not allowed to ramp up and down and maintain the same output throughout their operational lifetime. Coal generators can reduce output to a minimum loading level, incurring a heat rate penalty when below full load, but are also required to stay online throughout their operational lifetime in recognition of the time, cost, and emissions associated with starting them up. For generators that can vary output on a timepoint basis, ramp rate constraints have been implemented but are not currently enforced. This is because computational constraints limit the current temporal resolution of the SWITCH-WECC investment optimization. Timepoints to represent an investment period are sampled from two non-contiguous days for every month *every four hours*. With a ramp rate of 3.8 percent of capacity per minute, combined cycle gas generators can fully ramp in less than 30 minutes. Even considering startup time, four hours is likely sufficient time for a CCGT plant to ramp from zero to full load. Combustion turbines can be started up and ramped even faster. As a result, it is not necessary to enforce ramping constraints in the SWITCH-WECC investment optimization as they are always non-binding at the current level of temporal resolution.

2.5. Other System Flexibility Requirements

2.5.1. Frequency Regulation and Load-Following

Frequency regulation is an ancillary service that involves automatically varying the output of certain generators via automatic generation control (AGC) in response to fast changes in load, typically every few seconds to a minute. Load-following performs a similar function but on a longer time scale – usually every 5 or 10 minutes. It involves adjustments to generator output for active power balance and is usually procured through the energy market (e.g. the 5-minute economic dispatch in the CAISO market).

Neither frequency regulation nor load-following is directly included in SWITCH-WECC, although the “variability” reserves required as part of the operating reserve requirement in the model partly address this gap (GE Energy 2010), especially because they are usually provided by fast-ramping, low-carbon storage technologies in the long-term timeframe in the scenarios explored here. As frequency regulation and load-following requirements are over shorter timescales, the energy – and therefore capital investment – needed to meet these variations is likely small relative to the rest of the system, even as total requirements increase when wind and solar are added to the generation mix. Including frequency regulation into the SWITCH modeling framework is possible, but would involve additional complexity and computational requirements.

Frequency regulation is an important source of value for some storage technologies that can provide fast response ("Cost-Effectiveness of Energy Storage: Application of the EPRI Energy Storage Valuation Tool to Inform the California Public Utilities Commission Proceeding R. 10-12-007" 2013). This value is not captured in the results presented here. However, because of the small scale of the regulation requirement relative to the large energy needs of the system, I believe incorporation frequency regulation requirements into SWITCH-WECC would not result in substantial changes to the large-scale investment decisions of interest to this research. Both wind and PV technologies can likely contribute to frequency regulation as well as to inertial response and other grid support functions (Tielens and Van Hertem 2012). I do not include these requirements here in order to preserve computational feasibility.

2.5.2. System Inertia and Grid Stability

It remains an open question how the introduction of large amounts of renewable generation might affect grid stability attributes such as system frequency, voltage, reactive power flow, and so on. The inertial response of thermal generators is important to preventing large drops in frequency before the generator governors and AGC have been able to respond. That inertial response is decreased when wind and solar generation displaces conventional thermal generators (Eto et al. 2010; Sharma, Huang, and Sarma 2011). Little is known about the exact effect, so I do not currently include this impact in SWITCH-WECC. Both wind plants (Miller, Clark, and Shao 2011)and PV inverters (Tielens and Van Hertem 2012; Xue et al. 2011)can be equipped with control systems to provide inertial response at a relatively low additional cost. Like with frequency regulation, the total investment in infrastructure required to address system inertia issues is likely to be small relative to the total system cost.

2.5.3. Forecast Error

SWITCH currently can perform a linearized unit-commitment only and does not have the ability to assess costs resulting from suboptimal scheduling due to forecast error. To assess these impacts, it is necessary to use a simulation program of the unit commitment and economic dispatch process that simulates DC power flow to arrive at generator output and production cost estimates, as well as energy prices, emissions, transmission congestion, etc. The simulation requires the data inputs for load forecast and actual load, wind and solar forecast and realized production. Two optimizations are performed: one of the unit-commitment schedule based on the load and renewable forecasts and another of the economic dispatch closer to real time. As forecasts get more accurate, the gap between the two decreases and the cost of suboptimal commitment is reduced.

The effect of forecast error is currently not considered in SWITCH-WECC. Both the investment optimization and the verification step (see *Secton III.2* Temporal Resolution), perform a linearized unit-commitment of the system but not economic dispatch. The additional cost resulting from suboptimal scheduling therefore cannot be assessed here, but it is likely small relative to the total capital and operational cost of the system. In one study of the Irish grid, for example, a system based on of the portfolios from the All Island Grid Study (Meibom et al.) with 6 GW of wind was tested, providing 34.3 percent of total energy demand. The total capacity of the system was 8.3 GW, with the non-wind capacity consisting largely of baseload gas generation and some intermediate and peaking gas-fired as well as hydro plants. The study tested the performance of the system under stochastic, deterministic, and perfect forecasts. It found that perfect forecasting saves 0.8% over stochastic and 1.85% over deterministic methods (Tuohy et al. 2009).

3. System Flexibility Sources

3.1. *Electricity Storage Technologies*

3.1.1. Background

A number of energy storage technologies are available with varying characteristics ("Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits" 2010). To this day, however, only a few storage technologies have been deployed at a large scale, i.e. a total world capacity of more than 100 MW. Those include sodium-sulfur batteries, pumped hydro, compressed-air energy storage (CAES), and thermal storage. In the United States, there are 25 GW of utility-scale electric storage, most of which is pumped hydro storage (PHS) ("Grid Energy Storage" 2013). Multiple other technologies are currently being developed that can be deployed to provide grid services at various timescales.

Storage technologies are characterized by the total amount of energy they can store and the rate at which they can release it. A storage device therefore has two components: a storage unit with a $/kWh cost and a power conversion unit with a $/kW cost (Schoenung 2011; see Figure 3). Here, I will refer to the former as the storage project's *energy subsystem* and the latter as its *power subsystem*. For example, pumped hydro storage has a power subsystem consisting of hydro turbines and water pumps while its energy subsystem comprises of the lower and upper water reservoirs. Compressed air energy storage includes a combustion turbine and compressor as its power subsystem and an underground cavern for compressed air where energy is stored. Electrochemical cells are the energy subsystem component of most batteries while converter and control electronics determine the rate at which energy is released (the power output). I will use the term storage *duration* as the amount of time it would take for a fully charged storage project to fully discharge if releasing energy at its maximum possible rate. The overall cost of the system will be equal to the sum of total cost of its power subsystem (kW x $/kW) and the total cost of its energy subsystem (kWh x $/kWh).

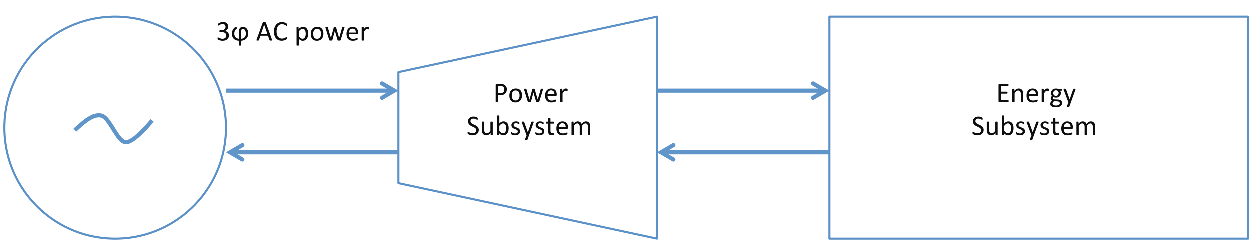


Figure 3. Energy storage subsystems. Based on Schoenung 2011.

The costs of the energy and power subsystems vary greatly across technologies and determine the suitable applications for each technology. Energy storage applications for the grid can be divided into several categories depending on the required power and duration, and are described below (Denholm et al. 2010; Schoenung 2011). Short-duration applications include frequency regulation, which requires the ability to continuously cycle and respond within less than a second in case of disturbances, as well as power quality applications, which require less frequent discharge. Technologies for short-duration applications include flywheels, supercapacitors, and a variety of battery chemistries. Longer duration applications include provision of operating reserves, which generally requires the ability to maintain the committed level of output for an hour, and of load following to compensate for unit-commitment errors. A small amount of cycling is generally required, as reserves are called upon infrequently, and a wide range of technologies is suitable for these applications.

On the super-hourly scale, energy management refers to the ability of storage to shift energy demand and supply over several hours. To provide energy management services, storage technologies must be able to discharge continuously over longer periods of time. Long-duration storage technologies include high-energy batteries, pumped hydro storage (PHS), compressed air energy storage (CAES), and thermal storage. Technologies suitable for energy management applications have lower $/kWh cost for the energy subsystem.

New storage in SWITCH-WECC includes two technologies, which are modeled after compressed air energy storage (CAES) and a generic battery technology respectively. Investment decision variables for storage projects determine both the power capacity of the project (the maximum rate at which energy can be released) and its energy capacity (the total amount of energy that can be stored by the project). For example, the model may decide to install a 1 MW project with 10 MWh of energy storage (a project that can release energy at a maximum rate of 1 MW for 10 hours) or a 10 MW project with 1 MWh of energy storage (a project that can release energy at a maximum rate of 10 MW for 6 minutes).

Per unit costs are input separately for storage power capacity and energy capacity. Default costs for CAES and batteries are based on sources by the Electric Power Research Institute and Black and Veatch respectively ("Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits" 2010; "Cost and Performance Data for Power Generation Technologies" 2012) and are shown in Table 8 below.

	Batteries		CAES	
Year	Power subsystem cost 2014$/KW	Energy subsystem cost 2014$/KWh	Power subsystem cost 2014$/KW	Energy subsystem cost 2014$/KWh
2010	1093	383	863	22
2015	1066	373	863	22
2020	1039	363	863	22
2025	1011	354	863	22
2030	984	344	863	22
2035	956	335	863	22
2040	929	325	863	22
2045	902	316	863	22
2050	874	306	863	22

Table 8. Storage power capacity and energy capacity costs by year.

3.1.2. Compressed Air Energy Storage

Compressed air energy storage (CAES) is a hybrid storage and gas turbine technology. Conventional gas turbines expend some of their gross energy to compress the air/fuel mixture for the turbine intake. CAES uses energy from the grid to compress air in an underground reservoir and uses that compressed air, adding it to the natural gas fuel for the turbine, for the turbine intake. Storage round-trip efficiency for CAES is assumed to be of 81.7 percent and plant round-trip efficiency is assumed to be 1.4 (Succar and Williams 2008). The plant round-trip efficiency is higher than 1 as CAES plants use both natural gas and electricity from the grid energy stored in the form of compressed air to produce power. A compressor to expander ratio of 1.2 (Greenblatt et al. 2007) is assumed.

CAES sites are assumed to be in aquifer geology. Geospatial aquifer layers are obtained from the United States Geological Survey ("Principal Aquifers of the 48 Conterminous United States, Hawaii, Puerto Rico, and the U.S. Virgin Islands" 2003) and all sandstone, carbonate, igneous, metamorphic, and unconsolidated sand and gravel aquifers are included (Succar and Williams 2008; "Handbook of Energy Storage for Transmission and Distribution Applications" 2003). A density of 83 MW/km^2 is assumed (Succar and Williams 2008), following, resulting in large CAES potential in almost all SWITCH-WECC load zones.[6]

[6] Geospatial work and CAES potential calculations were done by Dr. James H. Nelson.

3.1.3. Battery Storage

Batteries are available for installation in all load zones and investment periods in SWITCH-WECC. An AC-DC-AC round-trip storage efficiency of 75 percent is assumed. Battery lifetime is based on Lu et al. 2009. SWITCH-WECC allows 100% depth of discharge, so we take a battery life of 3142 cycles. Assuming frequent utilization, we calculate a battery lifetime of 10 years (3142 cycles / (10 yrs * 365 days/yr) = 0.86 cycles/day on average). In SWITCH, batteries are explicitly replaced at the end of their lifetime, so we assume that the variable O&M cost is zero (Walawalker 2008; Lu et al. 2009; "Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits" 2010). Battery capital and fixed O&M costs are from Black and Veatch ("Cost and Performance Data for Power Generation Technologies" 2012). Note that Black and Veatch includes the cost of battery replacement in the variable O&M cost for batteries and we therefore do not adopt their variable O&M value.

3.1.4. LP Formulation

In SWITCH-WECC, the amount of energy that can be stored in each study hour is limited by a storage facility's maximum store rate. For every storage project *sp* in every hour *t*, the amount of energy stored ($S_{sp,t}$) cannot exceed the product of a pre-specified store rate for that project (r_{sp}) and the total power capacity installed at that project in the current and preceding periods *i* ($IG_{sp,i}$), de-rated by the storage project's forced outage rate (o_{sp}). The store rate is 1 for battery projects and pumped hydro (i.e. the rate of storing energy is the same as the rate of releasing energy), and 1.2 for compressed air energy storage based on a compressor to expander ratio of 1.2 (Greenblatt et al. 2007). For pumped hydro, $IG_{sp,t}$ is equal to the preexisting power capacity as no new capacity can be installed in SWITCH-WECC.

MAX_STORE_RATE$_{sp,t}$

$$S_{sp,t} \leq (1 - o_{sp}) \times r_{sp} \times IG_{sp,i}$$

For every battery storage project *bp* in every hour *t*, the power from the storage project in that hour ($R_{bp,t}$) plus the operating reserve provided in that hour ($OP_{bp,t}$) cannot exceed the battery project's power capacity installed in the current period *i* ($IG_{bp,i}$), de-rated by the project's forced outage rate (o_{bp}).

MAX_BATTERY_POWER$_{bp,t}$

$$R_{bp,t} + OP_{bp,t} \leq (1 - o_{bp}) \times IG_{bp,i}$$

For every CAES storage project *cp* in every hour *t*, the power from storage ($R_{cp,t}$) and operating reserve ($OP_{cp,t}$) provided by the compressed air plus the power ($O_{cp,t}$), spinning reserve ($SR_{cp,t}$) and quickstart reserve ($Q_{cp,t}$) provided from the natural gas turbine cannot exceed the CAES project's total power capacity in period *i* ($IG_{cp,i}$), de-rated by the forced outage rate (o_{cp}).

MAX_CAES_POWER$_{cp,t}$

$$R_{cp,t} + OP_{cp,t} + O_{cp,t} + SR_{cp,t} + Q_{cp,t} \leq (1 - o_{cp}) \times IG_{cp,i}$$

CAES projects must also maintain the assumed ratio between power output from energy stored in the form of compressed air and power from natural gas fuel. For every CAES project *cp* in every hour *t*, the ration of power from storage ($R_{cp,t}$) and power from natural gas ($O_{cp,t}$) must equal a pre-specified ratio (*caes_ratio*). The parameter *caes_ratio* is derived from the storage efficiency and overall round-trip efficiency of CAES and is calculated to be 1.4.

CAES_COMBINED_POWER$_{cp,t}$

$$R_{cp,t} = O_{cp,t} \times caes\_ratio$$

For every CAES project *cp* in every hour *t*, the amount of operating reserve dispatched from the CAES project in that hour ($OR_{cp,t}$) must equal the operating reserve (spinning plus quickstart) dispatched from natural gas ($SR_{cp,t}$ + $Q_{cp,t}$) multiplied by the dispatch ratio between storage and natural gas (*caes_ratio*).

CAES_COMBINED_OR$_{cp,t}$

$$OR_{cp,t} = (SR_{cp,t} + Q_{cp,t}) \times caes\_ratio$$

In SWITCH-WECC, days are modeled as independent units, so the energy released by each storage project on each day must be less than or equal the energy stored by the project on that day, adjusted for the storage project's round-trip efficiency losses. For battery projects and CAES, the energy available in storage is tracked from timepoint to timepoint, and the implementation is circular over the day, i.e. the last hour of a given day is modeled as the previous hour for the first hour of that day. The energy available in storage ($ES_{sp,t}$) can never exceed the installed storage energy capacity in that period ($ISE_{sp,i}$).

MAX_ENERGY_IN_STORAGE$_{sp,t}$

$$ES_{sp,t \in T_i} \leq ISE_{sp,i}$$

No more energy can be released ($R_{sp,t}$) or reserved for operating reserves ($OR_{sp,t}$) in any hour *t* than the energy available in storage in that hour ($ES_{sp,t}$) plus any energy that the storage project stores from the grid in that hour ($S_{sp,t}$). As study timepoints are usually subsampled from the day and represent several consecutive hours of that day, a weight *hours_in_*day is assigned to each timepoint to reflect the total amount of energy that would be stored and released on all hours represented by that timepoint. An output duration requirement for operating reserves is enforced: operating reserves can only be committed when sufficient energy is available in storage to sustain the committed level of output for a pre-specified amount of time. The *duration_reqt* parameter is set to 1 hour by default.

MAX_STORAGE_ENERGY$_{sp,t}$

$$hours\_in\_day_t \times R_{sp,t} + duration\_reqt \times OR_{sp,t} \leq hours\_in\_day_t \times ES_{sp,t} + S_{sp,t} \times e_{sp}$$

For each storage project *sp* in each timepoint *t*, the energy available in storage in timepoint *t* ($ES_{sp,t}$) must equal the energy that was available in storage in the previous timepoint *t-1* plus the net energy that was released from storage in the previous timepoint (the energy $S_{sp,t-1}$ that was stored, de-rated by the storage project's efficiency (e_{sp}), minus the energy that was released $R_{sp,t-1}$). When timepoints are subsampled from the hours of day and represent multiple hours, a weight *hours_in_day* is applied to ensure that the correct amount of energy is calculated.

STORAGE_HOURLY_ENERGY_TRACKING$_{sp,t}$

$$ES_{sp,t} = ES_{sp,t-1} + hours\_in\_day \times (S_{sp,t-1} \times e_{sp} + R_{sp,t-1})$$

3.2. Concentrated Solar Power (CSP) with Thermal Energy Storage (TES)

3.2.1. General Approach

Five different solar technologies, each with different output characteristics, resource availability, and costs, are modeled in SWITCH-WECC, including residential, commercial, and central-station photovoltaic (PV) technologies and concentrated solar power (CSP) technologies with and without thermal energy storage (TES). CSP projects are assumed to be dry-cooled solar thermal trough systems sited on available rural land and a range of land exclusion criteria are applied (Nelson et al. 2012). For each project of a given technology, the hourly capacity factor of that project over the course of the year 2006 is simulated using the System Advisor Model (SAM) (*System Advisor Model* 2014)from the National Renewable Energy Laboratory (Nelson et al. 2013).

CSP systems with 100 MW nameplate capacity and without thermal storage are modeled in SAM using the 'CSP Trough Physical' model for parabolic trough systems. A solar multiple of 1.4 is assumed for systems without thermal storage. For prior work, the power output of CSP thermal storage was embedded in the hourly capacity factor calculated with SAM, using a pre-specified schedule of releasing energy from sunset through the early part of the night. Six hours of storage and a solar multiple of 2 were assumed.

As the power system generation mix and load profile change over time in response to climate change mitigation policy, population growth, efficiency implementation, or other factors, the optimal commitment schedule for CSP thermal storage is also likely to change. For this work, I have implemented the ability to determine how to optimally release energy from CSP with storage as an endogenous variable in SWITCH-WECC in response to power system conditions rather than as an exogenously specified input parameter.

To obtain the hourly energy availability for CSP projects with 6 hours of storage, I first match these projects via a location ID index to projects with no storage at the same location. I use the data on energy availability for CSP projects without storage, which are assumed to have solar multiples of 1.4, and assign hourly energy availability from the solar collection field of systems with 6 hours of storage by assuming they have a solar multiple of 2. The solar multiple is the ratio of the power capacity of the solar collection field to the capacity of the power block. For systems with same power block size, the hourly energy available from the solar collection field of CSP projects with 6 hours of storage is therefore (2/1.4) times the solar collection field energy availability of the projects without storage at the same location. This is the "capacity factor" that is input to SWITCH that determines the availability of energy to be scheduled from CSP projects with TES.

Due to computational constraints, the hourly commitment variables of CSP projects with 6 hours of storage are aggregated to the load zone level. They are then apportioned back to the project level based on relative project capacity. Parasitic losses from CSP plants with storage are ignored in this implementation as allowing them greatly increased runtime. In each timepoint, SWITCH can decide whether to directly release energy or to store it subject to hourly energy availability and capacity constraints. At this stage, CSP plants are not allowed to provide spinning or quickstart reserves.

3.2.2. LP Formulation

The direct output $OCSP_{z,t}$ from the CSP projects with storage (energy that is not stored first) and the amount of energy stored $SCSP_{z,t}$ in each timepoint cannot exceed the energy availability from the solar collection field in that hour. The energy availability is calculated as the project capacity IG_{csp} times the pre-specified hourly capacity factor cf_{csp} and de-rated by the project's forced outage rate o_{csp}.

MAX_CSP_SOLAR_FIELD_ENERGY$_{z,t}$

$$OCSP_{z,t\in T_i} + SCSP_{z,t\in T_i} \leq \sum_{csp\in CSP_z} IG_{csp}\times cf_{csp}\times(1-o_{csp})$$

Total power output from CSP with storage (the sum of direct output $OCSP_{z,t}$ and energy released from storage $RCSP_{z,t}$) is limited by the total installed project capacity (i.e. turbine size), de-rated by the forced outage rate o_{csp}.

MAX_CSP_POWER$_{z,t}$

$$OCSP_{z,t\in T_i} + RCSP_{z,t\in T_i} \leq \sum_{csp\in CSP_z} IG_{csp}\times(1-o_{csp})$$

We assume six hours of thermal energy storage, i.e. CSP with storage can release from storage at full load output for no more than six hours.

MAX_ENERGY_IN_CSP_TES$_{z,t}$

$$TES_{z,t\in T_i} \leq \sum_{csp\in CSP_z} 6\times IG_{csp}$$

The energy in storage in each timepoint is tracked in the same was as it is for batteries and CAES. The energy available in CSP TES in timepoint t in load zone z ($TES_{z,t}$) must equal the energy that was available in storage in the previous timepoint $t-1$ plus the net energy that was released from storage in the previous timepoint (the energy $SCSP_{z,t-1}$ that was stored, de-rated by the storage efficiency (e_{csp}), minus the energy that was released $RCSP_{z,t-1}$). When timepoints are subsampled from the hours of day and represent multiple hours, a weight *hours_in_day* is applied to ensure that the correct amount of energy is calculated.

CSP_TES_HOURLY_ENERGY_TRACKING$_{z,t}$

$$TES_{z,t} = TES_{z,t-1} + hours\_in\_day\times(SCSP_{z,t-1}\times e_{csp} + RCSP_{z,t-1})$$

3.3. Load Flexibility

By default, shiftable load is disabled. When it is enabled, the amount of load that can be moved from or to an hour via demand response for each demand category in each load zone is limited to a pre-specified amount of energy. Over the course of a day, the total demand moved from and to all hours must sum to zero for each demand category in each load zone – the total amount of demand met over the course of a day is the same with or without demand response. The two demand categories that can participate in demand response are electric vehicles and residential and commercial buildings. The amount of demand that can be moved from or to an hour from electric vehicles is calculated based on battery charging rates.

3.3.1. Demand Response from Thermal Loads

To calculate hourly shiftable-load potentials, we use hourly load data from Itron for commercial and residential loads disaggregated by end-use, along with assumptions about the fraction of each of these types of demand that will be shiftable in 2020, 2030, 2040, and 2050 (extrapolated linearly for years in between). The residential demand types we assume can be shifted include space heating and cooling, water heating, and dryers. Shiftable commercial building demand types include space heating and cooling as well as water heating.

Sector	End Use	2020	2030	2040	2050
Residential	Space heating	2%	20%	40%	60%
	Water heating	20%	40%	60%	80%
	Space cooling	2%	20%	40%	60%
	Dryer	2%	20%	60%	80%
Commercial	Space heating	2%	20%	40%	60%
	Water heating	20%	40%	60%	80%
	Space cooling	2%	20%	40%	60%

Table 9. Fraction of demand that is shiftable, by end use and year.

Based on the values in Table 9, we calculate the fraction of total residential and commercial demand respectively (after energy efficiency and heating electrification) in California that can be shifted and apply this fraction to each of SWITCH's California load zones to arrive at a total potential for shiftable demand by hour. We assume this demand can be shifted to any other hour in the same day. Since demand data disaggregated by sector and end-use is not available for the rest of WECC, we used the overall fraction of total non-EV demand calculated to be shiftable in California in each hour and applied that fraction to the hourly non-EV demand in each load zone in the rest of WECC to calculate shiftable demand availability. We assumed that shiftable demand potential in the rest of WECC lags that in California by a decade.

3.3.2. Demand Response from Electric Vehicles

Demand from electric vehicles (EV) is assumed to be shiftable subject to the battery charging rates of the EV fleet shown below.

	Percent of total EV demand				
Hours needed for full charge	**2012**	**2020**	**2030**	**2040**	**2050**
10	98.0%	91%	60%	20%	10%
4	1.8%	8%	38%	68%	70%
0.33	0.2%	1%	2%	12%	20%

Table 10. Assumed battery charging times of the electric vehicle fleet.

3.3.3. Total Potential

Shiftable load potential is shown in Table 4 and reaches an average of 20 percent of total hourly demand by 2050.

Year	Residential and Commercial		Electric Vehicles		Total	
	WECC-wide Average Hourly Shiftable Potential (MW)	Average Shiftable Percentage of Hourly Total Demand	WECC-wide Average Hourly Shiftable Potential (MW)	Average Shiftable Percentage of Hourly Total Demand	WECC-wide Average Hourly Shiftable Potential (MW)	Average Shiftable Percentage of Hourly Total Demand
2020	5	0.2%	2	0.1%	7	0.3%
2030	48	2%	32	1%	80	3%
2040	174	6%	154	5%	328	11%
2050	330	10%	368	10%	698	20%

Table 11. Shiftable load potential by load type and year.

3.3.4. LP Formulation

For every demand category *dc* in every load zone *a* in every hour *t*, the amount of demand moved from an hour via demand response ($DR_{dc,a,t}$) must be less than or equal to a pre-specified energy limit ($dr\_from\_limit_{dc,a,t}$).

$MAX\_DR\_FROM_{dc,a,t}$

$$DR_{dc,a,t} \leq dr\_from\_limit_{dc,a,t}$$

For every demand category *dc* in every load zone *a* in every hour *t*, the amount of demand moved to an hour via demand response ($MDR_{dc,a,t}$) must be less than or equal to a pre-specified energy limit ($dr\_to\_limit_{dc,a,t}$).

$MAX\_DR\_TO_{dc,a,t}$

$$MDR_{dc,a,t} \leq dr\_to\_limit_{dc,a,t}$$

For every demand category *dc* in every load zone *a* in every day *d*, the amount of demand moved from all hours *t* on day *d* (T_d is the set of hours on day *d*) via demand response ($DR_{dc,a,t}$) must be equal to the amount of demand moved to all hours *t* on day *d* via demand response ($MDR_{dc,a,t}$).

$DR\_ENERGY\_BALANCE_{dc,a,d}$

$$\sum_{t \in T_d} DR_{dc,a,t} = \sum_{t \in T_d} MDR_{dc,a,t}$$

3.4. Hydropower

3.4.1. General Approach

Hydroelectric generators must provide output in each hour equal to or exceeding a pre-specified fraction – usually 50% – of the average hydroelectric capacity factor for the month in which the study day resides in order to maintain downstream water flow. The total energy (which, for pumped hydro, includes energy released from storage) and operating reserves provided by each hydro project in each hour cannot exceed the project's total turbine capacity, de-rated by the forced outage rate of hydroelectric generators. Operating reserves from hydro cannot exceed a pre-specified fraction of installed capacity, 20 percent by default. The capacity factor for all hydroelectric facilities in a load area over the course of each study day must equal the historical daily average capacity factor for the month in which that day resides. New hydroelectric facilities are not built, but existing facilities are operated indefinitely. The dispatch of hydroelectric projects is aggregated to the load area level to reduce the number of decision variables. All load area level hydro dispatch decisions are allocated to individual projects on an installed capacity basis.

3.4.2. LP Formulation

For every hydroelectric project *hp* in every hour *t* on day *d* (T_d is the set of hours on day *d*), the amount of energy in dispatched by the project ($O_{hp,t}$) must be greater than or equal to a pre-specified average capacity factor for that project for that day ($cf_{hp,d}$), multiplied by the project's installed capacity (hg_{hp}), multiplied by a pre-specified minimum dispatch fraction (*min_dispatch_frac*), necessary to maintain stream flow.

$HYDRO\_MIN\_DISP_{hp,t}$

$$O_{hp,t\in T_d} \geq cf_{hp,d} \times hg_{hp} \times min\_dispatch\_frac$$

For every hydroelectric project *hp* in every hour *t*, the sum of watershed energy output ($O_{hp,t}$) and operating reserve ($OP_{hp,t}$) as well as, for pumped hydroelectric projects *php*, energy dispatched from storage ($R_{php,t}$), and operating reserve from storage (OP_{php}), cannot exceed the project's installed capacity (hg_{hp}) de-rated by the project's forced outage rate (o_{hp}).

$HYDRO\_MAX\_DISP_{hp,t}$

$$O_{hp,t} + R_{php,t} + OP_{hp,t} + OP_{php,t} \leq (1 - o_{hp}) \times hg_{hp}$$

For every hydroelectric project *hp* in every hour *t*, the amount of operating reserve dispatched ($OP_{hp,t}$) cannot exceed a fraction (*hydro_op_reserve_frac*) of the project's installed capacity (hg_{hp}).

HYDRO_MAX_OP_RESERVE$_{hp,t}$

$$OP_{hp,t} \leq hydro\_op\_reserve\_frac \times hg_{hp}$$

For every hydroelectric project *hp* and every day *d*, the historical average energy output must be met, i.e. the sum over all hours *t* on day *d* of energy dispatched by the hydroelectric project ($O_{hp,t}$) plus the fraction of time operating reserves are deployed (*op_reserve_deploy_frac*) multiplied by the operating reserve provided by the hydroelectric project ($OP_{hp,t}$) must equal the historical average capacity factor of the hydroelectric project ($cf_{hp,d}$) on day *d* multiplied by the project's installed capacity (hg_{hp}) multiplied by the number of hours simulated in day *d* ($num\_hours\_simulated_d$). T_d is the set of hours on day *d*.

HYDRO_AVG_OUTPUT$_{hp,d}$

$$\sum_{t \in T_d} (O_{hp,t} + op\_reserve\_deploy\_frac \times OP_{hp,t}) = cf_{hp,d} \times hg_{hp} \times num\_hours\_simulated_d$$

III. Modeling Approach and Scenario Development

1. Overview

In this study, I use a version of the SWITCH model for the electricity system of the Western Electricity Coordinating Council (WECC) to investigate decarbonization pathways for the WECC electricity system through 2050 in a range of scenarios. The WECC region has high-quality renewable resources and may experience relatively high operational impacts associated with intermittent generation, providing insight about the flexibility needs of a power system with high penetration levels of intermittent renewables. As the total resource potential, temporal profile of renewable output, and the temporal and geographic correlation between renewable output and load may differ in other regions, the specifics of the results may not be readily transferrable. However, the broader approach to investigating system flexibility needs can be applied to any geographic entity.

The results shown here will be structured around the level storage deployment in the WECC through 2050, but they are more generally about system decarbonization pathways and the associated system flexibility requirements. I will focus on the factors that effect the largest changes in technological deployment, system capacity and energy mix, and system unit-commitment across the scenarios studied and across time. I will organize the results by focusing on the near- to mid-term timeframe first (2020 and 2030) and then discuss the long term (2040 and 2050). Variation in parameters that make a large difference for the system composition and behavior in the 2030 timeframe may not be important to system development in 2050, and vice versa. For example, the price of natural gas is one of the most important factors for storage deployment levels in 2030, but its effect is small in the 2050 timeframe. On the other hand, the cost of battery technologies is a crucial driver of their deployment in the long term, but not through 2030.

These results are not meant to be a forecast. Rather, I explore a wide range of scenarios, including ones that may be considered unrealistic, in order to investigate the important drivers of infrastructure deployment choices and specific technological outcomes for the WECC power system, the tradeoffs and synergies among technologies, and the main dynamics that characterize different decarbonization pathways. I use a scenario-based approach to study the effect of sources of uncertainty and their relative importance.

The modeling approach and techniques used here builds on Fripp 2008, Fripp 2012, Nelson et al. 2012, Wei et al. 2013, and Mileva et al. 2013 by increasing the temporal resolution of the main SWITCH optimization to include peak net load hours, including an emissions true-up step similar to the method implemented in Nelson et al. 2013, and presenting results from a unit-commitment verification step that includes all test set timepoints rather than from the sampled timepoints in the main optimization training set.

2. Temporal Resolution

The version of SWITCH used here is a linear program (LP) that minimizes the cost of producing and delivering electricity to load on an hourly basis using a combination of existing and new grid assets. The model uses time-synchronized hourly load and intermittent renewable generation data to determine optimal investment in and hourly unit-commitment of generation, transmission, and storage.

New generation, storage, and transmission capacity can be built at the start of each of four "investment periods," representing 2016−2025, 2026−2035, 2036−2045, and 2046−2055. Throughout this manuscript, I will also refer to the four investment periods as 2020, 2030, 2040, and 2050, respectively. The investment decisions determine the availability of power system infrastructure to be used (i.e. committed) in each "study timepoint," sampled from a year of hourly data for each period. Investment and unit-commitment decisions are optimized simultaneously.

Wind and solar conditions for each investment period are represented by historical data from 2006. The renewable output data is time-synchronized to historical hourly load data from 2006, scaled to projected future demand and shaped by the implementation of energy efficiency, vehicle electrification, and heating electrification (Wei et al. 2013; Nelson et al. 2013). Study timepoints 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. This approach aims to include a wide range of demand and atmospheric conditions. Each subsampled day is assigned a corresponding weight: one day per month for peak load days and the number of days in a month minus one for the median load day. The goal of the weighting method is to ensure that the cost of the power system is driven largely by the 'average' conditions it faces but that sufficient capacity is available during times of high grid stress. For peak days, the peak hour is always included with five more hours sampled from the day spaced four hours apart. For median load days, hourly sampling in the main optimization begins at 2 am Greenwich Mean Time (GMT). This sampling approach for median days was chosen over beginning at hours 0, 1, or 4 because it introduces the smallest difference between the population mean and the sample mean of solar insolation potential in the WECC.

As the SWITCH investment optimization uses a limited number of sampled hours over which to commit the electric power system infrastructure, unit-commitment verification is performed at the end of each investment optimization to ensure that the model has designed a power system that can in fact meet load and other constraints. In this verification, investment decisions are held fixed, and new hourly data for a full year are tested in batches of one day at a time. For the scenarios investigated here, several iterations were performed between the investment optimization and the unit-commitment optimization to determine the times when the largest capacity shortfalls occurred for a range of scenarios, i.e. the times of highest peak net load that were not accounted for by the initial sampling method. These days were then added to the main optimization training set. Data from three additional days (a day in January, a day in July, and a day in December) were added to the 2050 investment period, and one more day was added to the 2040 investment period. Hours from the additional days were subsampled every four hours. The results presented here are therefore based on an investment optimization that includes a total of 600 timepoints and on a unit-commitment optimization that include 8760 hours, optimized one day at a time.

3. Carbon Emissions Cap and Emissions True-Up

In addition to capacity shortfalls, the main SWITCH optimization may design a system that has emissions levels higher than planned for: the carbon cap enforced in the investment optimization may not always result in the same emissions level that is calculated by the unit-commitment optimization. The difference in emissions between the investment and unit-commitment optimizations tends to be relatively small for scenarios that do not include drastic emission reductions, but the gap increases to several percentage points relative to 1990 levels in scenarios that reduce emissions to more than 80 percent below 1990 levels by 2050.

Scenarios presented here meet a WECC-wide carbon cap of 100 percent of 1990 levels in 2020, which is then decreased linearly to 85 percent below 1990 levels in 2050 in the unit-commitment verification step. The 1990 emissions baseline for WECC is 285 $MtCO_2$/yr, so the emissions level in 2050 is (1 - 0.85) * 285 $MtCO_2$/yr = 43 $MtCO_2$/yr.

For this study, I performed multiple iterations of the investment optimization for each scenario, noting the carbon emissions in the unit-commitment verification step and adjusting the carbon cap in the investment optimization downward if the system's emissions in the exceed the carbon goal when unit-commitment was performed on the full test set. This approach was first implemented in Nelson et al. 2013. All scenarios presented here have the same emissions in the unit-commitment verification step in 2050: 85 percent below 1990 emissions levels.

4. Reference Scenario

The *Reference* scenario developed here is just that: a reference point from which to base variations in a range of input parameters. The *Reference* scenario assumptions for technological cost, fuel price, technological capability, technological availability, etc. are not necessarily more likely than the assumptions in other scenarios.

I include a brief description of the main data inputs to the SWITCH-WECC model here. A complete discussion of the SWITCH-WECC data as well as assumptions and model formulation is available at http://rael.berkeley.edu/switch.

4.1. Technology Availability, Technology Costs, and Fuel Prices

In the *Reference* scenario (as well as all but the *Nuclear and CCS* scenario), I will assume that neither nuclear plants nor fossil fuel plants with carbon capture and sequestration (CCS) will be built through 2050. My focus here is on systems in which low-carbon baseload technologies are not available and intermittent renewable technologies are the main source of carbon-free electricity. The goal is to understand the flexibility requirements – and in particular the role of storage – in such systems. I will also assume that biomass fuel is not available to the electricity sector but is instead used for transportation purposes, further limiting the availability of carbon-free baseload. The potential for bio energy carbon capture and sequestration (BECCS) and negative emissions from such plants 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. Table 12 shows the overnight capital cost, fixed operations and maintenance costs, and variable operation and maintenance cost input parameters used in this study. Low-carbon baseload technologies such as nuclear and CCS are excluded from the *Reference* scenario but are shown in Table 12.

The price of natural gas in the *Reference* is based on the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2012 Base Case ("Annual Energy Outlook" 2012) and is shown in Figure 4. The EIA AEO 2012 does not project the price of natural gas beyond 2035, so value between 2035 and 2050 are extrapolated based on the data for 2025-2035. I have developed a treatment of natural gas price elasticity to reflect the relationship between the overall level of natural gas consumption and the price of natural gas. An inverse wellhead price elasticity of 1.2 is assumed (i.e. 1 percent change in quantity results in 1.2 percent change in price) for natural gas based on the median value from Wiser, Bollinger, and St. Clair 2005, with consumption outside of the WECC assumed as projected in the 2012 AEO.

The cost of new transmission capacity is assumed to be \$1,130 per MW of thermal capacity per km (\$2013).

Fuel	Technology	Overnight Capital Cost ($2013/W)	Fixed O&M ($2013/MW/Yr)	Variable O&M ($2013/MWh)
Bio Gas	Bio Gas	1.98	60000	15
Coal	Coal IGCC	4.21	33000	6.9
Coal	Coal Steam Turbine	3.04	24000	3.9
Coal CCS	Coal IGCC CCS	6.94	47000	11.1
Coal CCS	Coal Steam Turbine CCS	5.93	37000	6.3
Gas	CCGT	1.29	7000	3.9
Gas	Gas Combustion Turbine	0.68	6000	31.4
Gas CCS	CCGT CCS	3.94	19000	10.5
Geothermal	Geothermal	6.24	0	32.6
Solar	Central PV (2020)	2.64	47000	0
Solar	Central PV (2030)	2.43	43000	0
Solar	Central PV (2040)	2.27	39000	0
Solar	Central PV (2050)	2.13	35000	0
Solar	Commercial PV (2020)	3.51	47000	0
Solar	Commercial PV (2030)	3.11	43000	0
Solar	Commercial PV (2040)	2.91	39000	0
Solar	Commercial PV (2050)	2.75	35000	0
Solar	CSP Trough 6h Storage (2020)	6.86	53000	0
Solar	CSP Trough 6h Storage (2030)	5.58	53000	0
Solar	CSP Trough 6h Storage (2040)	4.94	53000	0
Solar	CSP Trough 6h Storage (2050)	4.94	53000	0
Solar	CSP Trough No Storage (2020)	4.77	53000	0
Solar	CSP Trough No Storage (2030)	4.38	53000	0
Solar	CSP Trough No Storage (2040)	3.99	53000	0
Solar	CSP Trough No Storage (2050)	3.6	53000	0
Solar	Residential PV (2020)	3.94	47000	0
Solar	Residential PV (2030)	3.46	43000	0
Solar	Residential PV (2040)	3.25	39000	0
Solar	Residential PV (2050)	3.08	35000	0
Uranium	Nuclear	6.41	133000	0
Wind	Offshore Wind (2020)	3.31	105000	0
Wind	Offshore Wind (2030)	3.14	105000	0
Wind	Offshore Wind (2040)	3.14	105000	0
Wind	Offshore Wind (2050)	3.14	105000	0
Wind	Wind	2.08	63000	0

Table 12. Generator and storage costs, in real 2013 dollars.

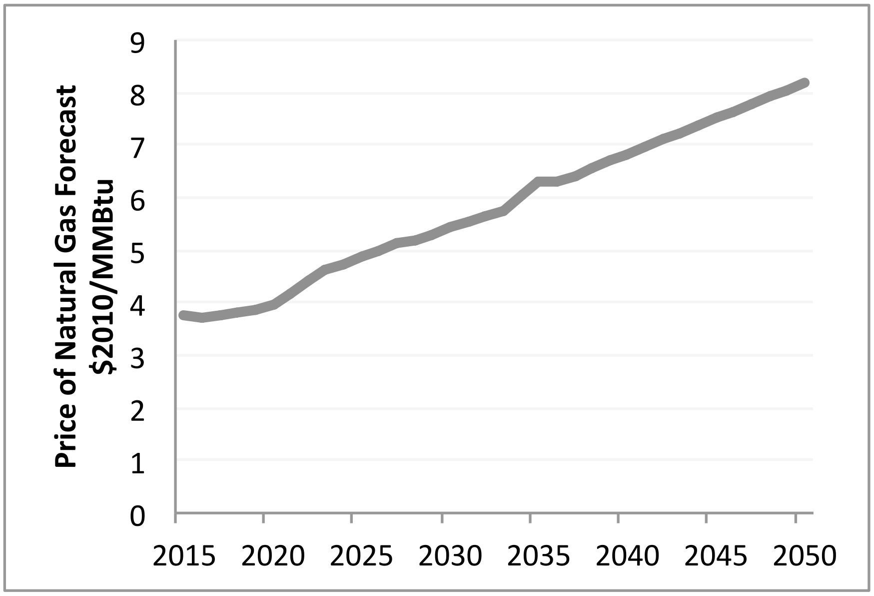


Figure 4. Price of natural gas in the EIA AEO 2012 Base Case.

4.2. Demand Profile

The hourly demand profiles used in this study are based on historical demand data from 2006 and modified in future years by the introduction of energy efficiency measures, vehicle electrification, and heating electrification. A detailed discussion of the profiles is available in (Wei et al. 2013) and the total yearly demand through 2050 is shown in Figure 5. The black line labeled “Total Demand” is the input demand used here in all but the *Limited Efficiency* scenario.

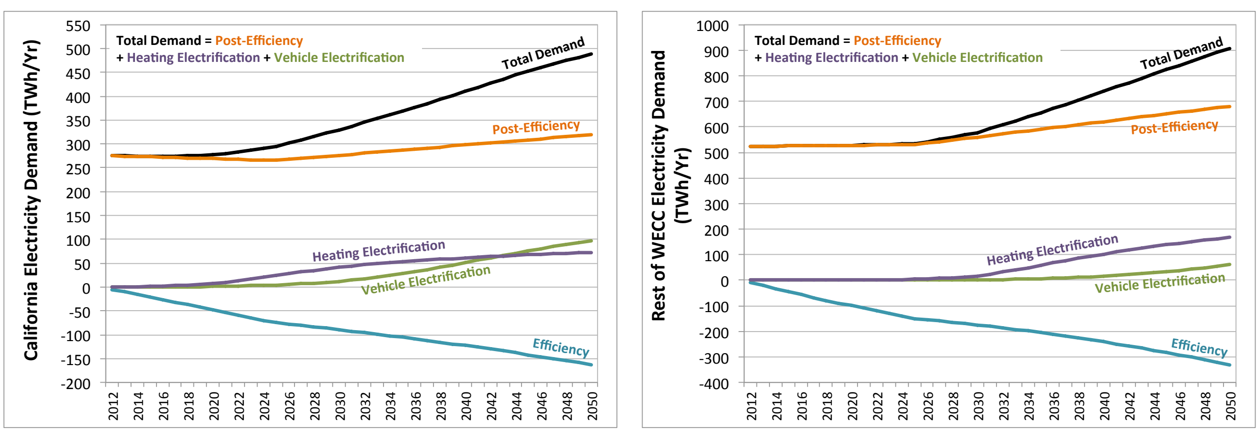


Figure 5. Total yearly demand in California (left) and the rest of WECC (right) through 2050. Graph from Wei et al. 2012 and Nelson et al. 2013.

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 (Figure 6). The total demand increases relative to the base demand without efficiency and electrification.

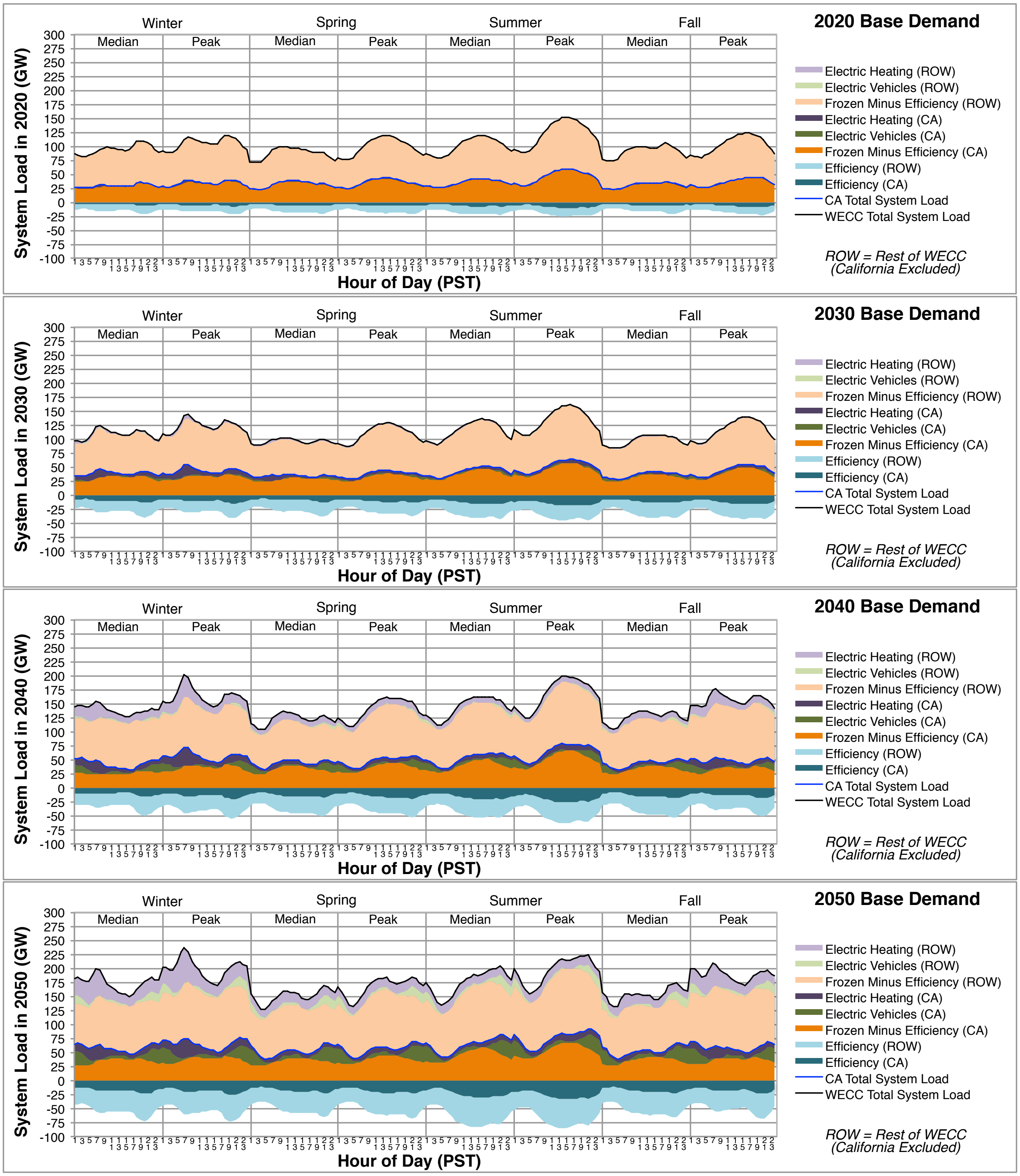


Figure 6. Demand profile by decade. The peak and median load day of each season are shown. Graph from Wei et al. 2013 and Nelson et al. 2013.

4.3. *Reference Scenario Summary*

A summary of the main inputs to the *Reference* scenario are shown in Table 13. A detailed description of the sensitivity scenarios is provided below.

Input parameter	Reference Scenario	Sensitivity
Carbon cap	100% of 1990 emissions levels in 2020 Linear decrease to 85% below 1990 emissions levels in 2050	
Generation	New nuclear excluded (existing nuclear given option to run) Carbon capture and sequestration (CCS) excluded	Include nuclear and CCS
	Hydropower at historical (2004-2011) average generation levels	Limit hydro energy availability to 50% of historical levels by 2050
	Solar costs as projected by Black & Veatch (central PV: ~$2.5/W by 2020 and ~$2/W by 2050; CSP with 6h storage: ~$6/W by 2020 and ~$4.5/W by 2050)	SunShot solar costs (central PV: ~$1/W by 2020; CSP with 6h storage: ~$3/W by 2020)
Storage	Battery costs as projected by Black & Veatch (~500/kWh in 2020, $400/kWh in 2050 for total system cost)	Battery costs at ARPA-E targets in 2020 (~100/kWh for total system cost)
Natural gas	Price from EIA NEMS Annual Energy Outlook Base Case 2012 (~$4/MMBtu in 2020, ~$8/MMBtu in 2050)	Double *Reference* price
	No methane leakage	Methane leakage at 4%
Demand profile	Electrification of heating and vehicles Technical potential energy efficiency	Limited efficiency
Demand response	Disabled	Enable load-shifting for thermal loads Enable flexible charging of EVs
Transmission	Base cost of ~$1130/MW-km (before terrain multipliers)	Triple Reference price

Table 13. Summary of the Reference *scenario inputs and sensitivities.*

5. Technology Cost Sensitivities

5.1. Solar Technology Costs

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 photovoltaics (PV) and concentrating solar power (CSP) ("SunShot Initiative" 2014). The cost targets are shown in Table 14. The SunShot Vision Study ("SunShot Vision Study" 2012) provides an extensive analysis of the innovation required to reach the SunShot targets and the effect on solar deployment in the United States. I have previously explored the implications of achieving these targets for technology deployment and electricity costs in the WECC in scenarios limiting carbon emission from the electricity sector (Mileva et al. 2013).

Building on my prior work, here I have implemented an important enhancement to SWITCH's treatment of CSP with thermal energy storage (see II.3.2 Concentrated Solar Power (CSP) with Thermal Energy Storage (TES)). Previously, the unit-commitment schedule of CSP storage was an exogenously determined input into the SWITCH model calculated with the System Advisor Model (SAM) (*System Advisor Model* 2014) rather than an endogenous variable. Furthermore, the focus of the current work is in particular on the additional flexibility requirements imposed by various solar technologies and the interactions among solar, wind, and storage in the decarbonizing WECC power system.

SunShot solar costs are used in the *SunShot* scenario and the *SunShot and Low-Cost Batteries* scenario.

Solar Technology	Year	*Reference* Capital Cost $2014/W$_p$	*SunShot* Capital Cost $2014/W$_p$
Central Station PV	2020	2.64	1.08
Central Station PV	2030	2.43	1.08
Central Station PV	2040	2.27	1.08
Central Station PV	2050	2.13	1.08
Commercial PV	2020	3.51	1.34
Commercial PV	2030	3.11	1.34
Commercial PV	2040	2.91	1.34
Commercial PV	2050	2.75	1.34
Residential PV	2020	3.94	1.61
Residential PV	2030	3.46	1.61
Residential PV	2040	3.25	1.61
Residential PV	2050	3.08	1.61
CSP Trough No Thermal Storage	2020	4.77	2.69
CSP Trough No Thermal Storage	2030	4.38	2.69
CSP Trough No Thermal Storage	2040	3.99	2.69
CSP Trough No Thermal Storage	2050	3.60	2.69
CSP Trough 6 Hours Thermal Storage	2020	6.86	3.29
CSP Trough 6 Hours Thermal Storage	2030	5.58	3.29
CSP Trough 6 Hours Thermal Storage	2040	4.94	3.29
CSP Trough 6 Hours Thermal Storage	2050	4.94	3.29

Table 14. Reference and SunShot solar costs by year and solar technology.

5.2. Battery Technology Costs

As discussed in II.3.1 Electricity Storage Technologies, storage technologies have two cost components: a storage unit with a $/kWh cost and a power conversion unit with a $/kW cost. This treatment of storage is an enhancement over prior work, in which the duration of storage was an input to SWITCH rather than a variable. Only CAES with 16 hours of storage and batteries with 8 hours of storage were available to the optimization in prior studies (Nelson et al. 2012; Wei et al. 2013; Mileva et al. 2013; Nelson et al. 2013). For this study, I have implemented a two-variable treatment of storage investment in SWITCH-WECC: the optimization decides both the capacity of the power subsystem component and the energy subsystem component of both CAES and batteries endogenously. The model can therefore determine the optimal size of storage devices for a given cost structure.

Two distinct cost trajectories for batteries are modeled here. *Reference* scenario costs are based on cost projections by Black and Veatch ("Cost and Performance Data for Power Generation Technologies" 2012) and decline slowly between present day and 2050. To explore the effect of strong technological innovation and deep cost-reductions in battery technology, I also run two scenarios in which battery costs decline to ~$500/kW for the power subsystem component and ~50/kWh for the energy subsystem component, a likely lower bound for what is achievable by flow batteries (Larochelle 2012). This is equivalent to the ARPA-E battery total system cost target of $100/kWh. For comparison, CAES costs are ~800/kW for the power subsystem component and ~$20/kWh for the energy subsystem component.

Battery costs at the ARPA-E target level are used in the *Low-Cost Batteries* scenario and the *SunShot and Low-Cost Batteries* scenario.

	Reference		***ARPA-E***	
Year	**Power subsystem cost** 2014$/kW	**Energy subsystem cost** 2014$/kWh	**Power subsystem cost** 2014$/kW	**Energy subsystem cost** 2014$/kWh
2015	1066	373	805	192
2020	1039	363	518	46
2030	984	344	518	46
2040	929	325	518	46
2050	874	306	518	46

Table 15. Reference and ARPA-E costs of the power subsystem and the energy subsystem of battery technology by year.

6. Natural Gas Sensitivities

6.1. Background

Natural gas has been touted as a “bridge” fuel that has the potential to play a vital role in reducing greenhouse gas emissions from the electricity sector. Recent advancements in hydraulic fracturing (“fracking”) technology for shale gas have greatly reduced the price of the fuel, allowing natural gas generation to be competitive with coal on a cost basis while emitting half as much carbon as coal plants. Furthermore, natural gas generators can ramp quickly and compensate for the intermittent output of wind and solar generation, thus aiding in the integration of these carbon-free energy resources into the grid and enabling further emission reductions. Natural gas may have value as a source of low-emission flexibility, but a deeper investigation is required to determine the drivers of and constraints on its use.

6.2. Natural Gas Price

Natural gas generation, in particular quick-ramping combined cycle gas turbines and combustion turbines, are an important source of flexibility to the power system. Their cost-effectiveness relative to other sources of flexibility is dependent on both the capital cost of natural gas plant infrastructure and on the variable fuel cost for running those plants. To investigate the effect of higher natural gas prices on the infrastructure deployment and unit-commitment in the WECC power system, I investigate a *High-Price Natural Gas* scenario in which natural gas prices is doubled relative the EIA AEO 2012 Base Case projections for a given consumption level.

6.3. Methane Leakage in the Natural Gas Upstream Supply Chain

The ability of natural gas fuel use to reduce greenhouse gas emissions relative to coal is dependent on the level of leakage of methane – a potent greenhouse gas – in the supply chain. While fracking has provided an abundant and inexpensive source of gas relative to traditional wells, it also has higher leakage rates, potentially negating the climate benefits of natural gas over coal (Brandt et al. 2014). In the *Methane Leakage* scenario, I incorporate supply-chain natural gas leakages into SWITCH-WECC to determine how the optimal deployment of natural gas generators is impacted by upstream leakage. A recent estimate is that between 3.6 and 7.9 percent of the methane from shale-gas production leaks over the lifetime of a well (Howarth, Santoro, and Ingraffea 2011). I model a leakage rate of 4 percent, i.e. 4 percent of the total recovered natural gas leaks upstream, so only 96 percent of the recovered fuel is used in gas-fired plants). These upstream emissions are added to the total emissions of natural gas in the SWITCH optimization.

$$LeakageEmissions = NaturalGasUsed \times \frac{leakage\_rate}{1 - leakage\_rate}$$

For every MMBtu of natural gas used in SWITCH, [leakage_rate / (1 - leakage_rate)] MMBtu are assumed to have leaked upstream. I use the 100-year global warming potential to calculate the CO_2-equivalent of the upstream methane emissions. For a 4 percent leakage rate, the CO2-eq per MMBtu of natural gas used in SWITCH is 0.028 tonnes (Table 16).

Leakage rate	Tonnes CO2-eq leaked upstream per MMBtu natural gas used
0%	0.000
1%	0.007
2%	0.014
3%	0.021
4%	0.028
5%	0.035
6%	0.043
7%	0.050
8%	0.058

Table 16. Upstream methane leakage CO2-eq as a function of leakage rate.

7. Low-Carbon Baseload Sensitivity

In the *Nuclear and CCS* scenario, I make nuclear and carbon capture and sequestration technologies available to the investment optimization to explore a decarbonization pathway, in which low-carbon baseload power is dominant in the system and reliance on intermittent renewable energy is reduced. New nuclear generation capacity is currently prohibited from being built in California and that policy is assumed to remain in place, although energy from new nuclear plants may be imported into the state.

8. Demand Profile Sensitivity

In the *Reference* scenario, the demand profile input to SWITCH includes aggressive implementation of energy efficiency measures, including widespread adoption of a range of present-day energy efficiency technologies at “technical potential” levels. ‘Technical potential” includes energy efficiency technologies that are commercial today, but may not have reached cost-effectiveness.

The *Limited Efficiency* scenario explores the effect on the power system of not achieving technical potential efficiency. The *Limited Efficiency* demand profile was developed in Wei et al. 2013 and Nelson et al. 2013. Electricity savings from energy efficiency in this scenario are assumed to be 50 percent of present-day technical potential for every end-use across WECC, excluding electrified heating and vehicles. We also assume a 20 percent increase in electric space heating demand, reflecting the possibility that building shells may not achieve technical potential efficiency. Little increase in water heating efficiency is assumed in the base demand profile used in the *Reference* scenario, so decreased efficiency in electric water heating has negligible impact. The overall increase in space heating demand results in about a 10 percent increase in total electric heating demand in 2050 relative to the base demand profile (space and water heating each constitute roughly half of total electric heating demand). Increased demand from inefficient electric vehicles is not included.

The *Limited Efficiency* scenario has an increase in demand of 18% in 2050 relative to the *Base Scenario*, representing 258 TWh of additional electricity demand across WECC.

9. System Flexibility Sensitivities

9.1. High-Cost Transmission

Transmission is a source of flexibility in the power system as it allows for supply and demand to be matched in space by transporting electricity over long distances. It is particularly important because the highest quality renewable resources are often found at remote location and require transmission to connect them to load. Transmission availability plays an important role in the integration of renewable generation as it can help realize the benefits of geographic diversity to smooth intermittent output as well as mitigate the need for curtailment by allowing for power to be exported to where it is needed. However, transmission planning and approval has historically involved substantial lead times. In the *High-Cost Transmission* scenario, I increase the cost of building new transmission threefold to $3,390 per MW of thermal capacity per km ($2013) with the goal of capture the effect of more limited transmission deployment on the flexibility requirements, technology mix, and cost of the power system.

9.2. Limited Hydro Energy Availability

Reduced precipitation and snowpack levels from climate change may result in lower snowmelt and lower water availability for hydroelectric energy production in the future. To explore the implications of lower energy availability from hydropower in the WECC, I include the *Limited Hydro* scenario, in which I reduce the average capacity factor of each hydropower plant modeled in SWITCH-WECC on a linear schedule between historical averages (the average of the years 2004 to 2011) in the present day to 50 percent below average historical levels by 2050. Changes in the regional or seasonal variability in runoff are not modeled.

9.3. Limited Hydro Flexibility

Due to short startup times and its ability to ramp up and down quickly, hydropower may be an important source of flexibility to the power system that can help to integrate intermittent renewable sources into the grid. While technically capable of flexible operation, however, hydropower is subject to a variety of streamflow constraints as it also serves of a wide range of environmental and recreational purposes. To explore effect on the power system of limiting the use of hydropower to follow net load and balance renewables, I run the *Limited Flexibility Hydro* scenario, in which I increase the minimum flow constraint on hydropower from 50 percent of the average flow to 75 percent of the average flow, thus decreasing the hydro energy available for load-following in half.

9.4. High-Efficiency Batteries

The *High-Efficiency Batteries* scenario explores the effect of increasing the round-trip efficiency of battery technologies from 75 percent to 90 percent.

9.5. Load-Shifting

The availability of flexible loads may make it possible to increase the penetration level of intermittent renewables while potentially also reducing system costs by aiding in load balancing and allowing for more inexpensive – but temporally constrained – resources to be used. To explore how flexible loads can contribute to increased utilization of intermittent renewables and lower system costs, I collaborated with Dr. Max Wei from the Lawrence Berkeley National Laboratory (LBNL) to obtain load response availability estimates by end-use for the commercial and residential sectors. Details are available in *Section II.3.3* Load Flexibility.

I include this potential in the *Load-Shifting* scenario and allow SWITCH to shift load within each day, thus providing flexibility to the power system. The ability to shift load is excluded in other scenarios, as little information currently exists about the true shiftable load potential and the costs. In the *Reference* scenario, therefore, shiftable load is not included to provide an upper bound on system costs. In the *Load-Shifting* scenario, demand response is a zero-cost resource that can be used by the optimization to help integrate renewables. The difference in costs between the *Reference* scenario and the *Load-Shifting* scenario can therefore be interpreted as the value of shiftable load resource.

9.6. Flexible EV Charging

In addition to the ability to shift residential and commercial thermal loads, the *Flexible EV Charging* scenario also has the option to decide when to charge electric vehicles. Details about the potential assumed are in *Section II.3.3.2* Demand Response from Electric Vehicles.

10. Other

Two more scenarios are explored in this study, the *No CSP* scenario and the *No CSP and 100 GW Solar PV Limit* scenario. The goal of these scenarios is to force the SWITCH optimization to create power systems that are highly reliant on wind energy in order to explore the flexibility requirements of wind power.

11. Summary of Scenarios

Table 17 below shows a summary of the scenarios that are investigated here.

Scenario name	Demand profile	Electricity generation options	Policy options	System flexibility	2050 WECC electricity carbon cap (vs. 1990)
Reference	Reference	Reference	Reference	Reference	15%
SunShot Solar	Reference	**SunShot solar technology available**	Reference	Reference	15%

Low-Cost Batteries	Reference	Reference	Reference	**Low-cost battery technology available**	15%
High-Efficiecy Batteries	Reference	Reference	Reference	**High-efficiency battery technology available**	15%
SunShot and Low-Cost Batteries	Reference	**SunShot solar technology available**	Reference	**Low-cost battery technology available**	15%
High-Price Natural Gas	Reference	**Natural gas price doubled**	Reference	Reference	15%
Methane Leakage	Reference	Methane leakage rate at 4%	Reference	**Reference**	15%
Nuclear and CCS	Reference	**New nuclear allowed outside California; CCS allowed (no coal in California)**	Reference	Reference	15%
Limited Efficiency	**Reduced efficiency implementation**	Reference	Reference	Reference	15%
High-Cost Transmission	Reference	Reference	Reference	**Cost of New Transmission Tripled**	15%
Limited Hydro	Reference	Reference	Reference	**Energy availability from hydro decreased linearly to 50% by 2050**	15%
Load-Shifting	Reference	Reference	Reference	**Shifting of thermal loads allowed**	15%

Load-Shifting and Flexible EV Charging	Reference	Reference	Reference	**Shifting of thermal loads and flexible charging of EVs allowed**	15%
No CSP 6h Storage	Reference	**CSP excluded**	Reference	Reference	15%
No CSP and Solar PV 100 GW Limit	Reference	**CSP excluded; solar PV deployment limited to 100 GW**	Reference	Reference	15%

Table 17. Summary of scenarios.

IV. System Flexibility Requirements in the Near- and Mid-Term Timeframe

1. System Development Summary

The development of the WECC power system through 2030 varies little across scenarios before diverging widely in later investment periods. The 2020 *Reference* scenario system is similar to the present day power system (Figure 7). Generation in California is dominated by natural gas and complemented by some wind and solar deployment as well as hydropower and one nuclear plant (Diablo Canyon). The rest of the Southwest also relies on natural gas as well as deployment of solar PV. The Pacific Northwest is reliant on hydropower and exports some hydro energy to California. Existing coal plants, located largely in the eastern part of the WECC, are a major energy source in those areas, complemented by deployment of wind power in the Rockies, and some of this energy is transmitted southward and westward.

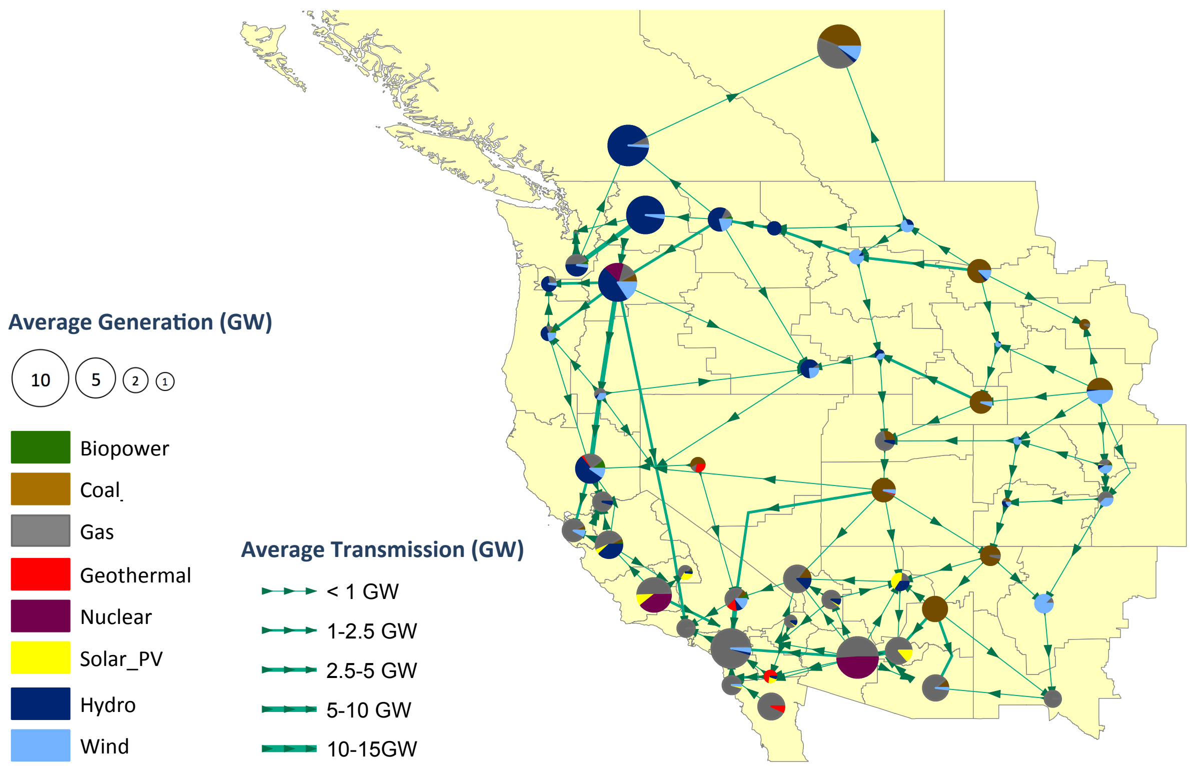


Figure 7. Map of average hourly generation and transmission, Reference *scenario, 2020.*

By 2030, changes take place in the *Reference* system, with almost all coal replaced by natural gas plants as well as further expansion in renewable deployment: solar PV in California and Arizona, wind in the Pacific Northwest and the eastern part of the WECC (Figure 8). Natural gas use also increases in California and hydropower continues to provide a large fraction of energy in the Pacific Northwest, but transmission lines to California are used less than in 2020. Wind power is deployed in the eastern part of the WECC and shipped to the load centers in the Southwest.

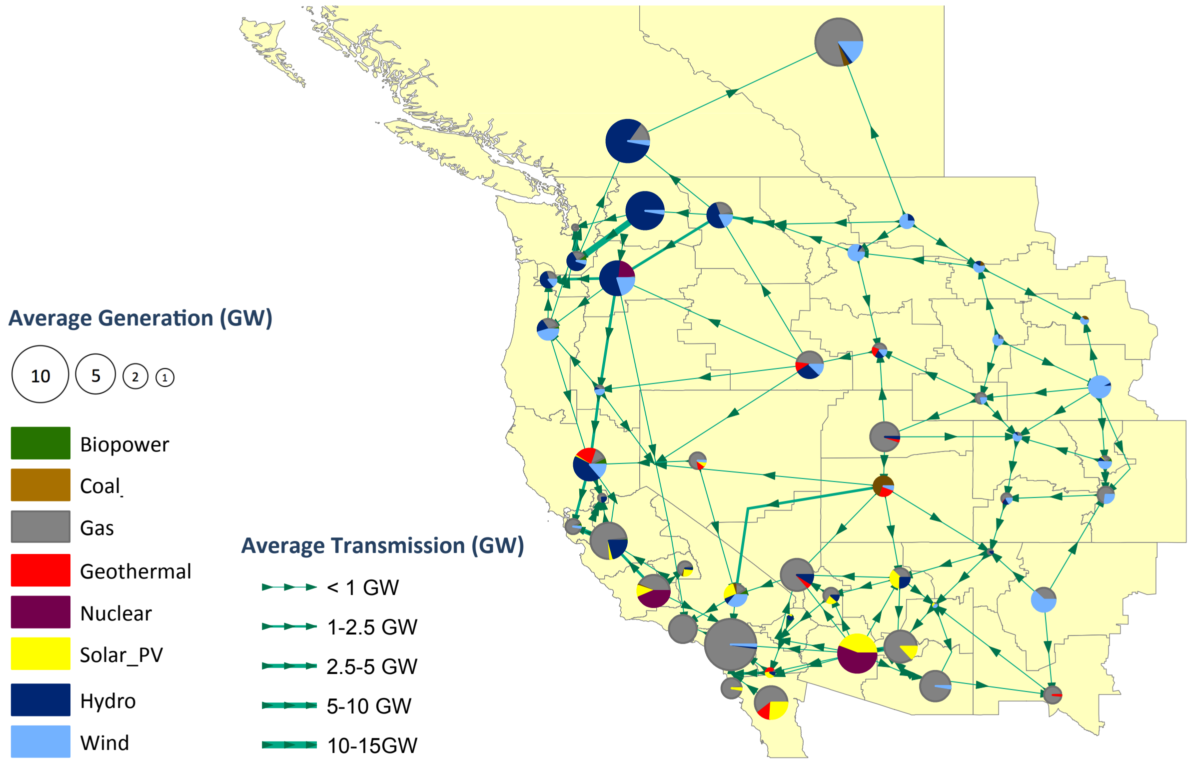


Figure 8. Map of average hourly generation and transmission, Reference *scenario, 2030.*

2. Electricity Production and Generation Capacity in 2020

Figure 9 shows the WECC electricity production mix in 2020 across the modeled scenarios. Coal, gas, and hydro generation dominate these systems. Among renewable technologies, wind is the largest energy contributor, providing around 10 percent of all electricity production in most scenarios. The effect of the parameters varied across scenarios tends to be small in this timeframe. Among the largest changes relative to the Reference scenario occur if solar technologies become inexpensive in the *SunShot* scenario; if either the price or emission level of natural gas fuel is higher in the *High-Price Natural Gas* and *Methane Leakage* scenario respectively; if efficiency measures are not implemented in the *Limited Efficiency* scenario; and if the availability of hydropower is low in the *Limited Hydro* scenario.

If SunShot solar costs are reached by 2020, solar deployment displaces most wind, providing 8 percent of generated electricity in this timeframe, but the rest of the electricity mix stays similar. Inexpensive solar also displaces some gas generation whose share goes from 33 percent in the *Reference* scenario to 30 percent in the *SunShot and Low-Cost Batteries* scenario. In the 2020 timeframe, the fraction of electricity generated from natural gas is not very sensitive to the parameters varied across the scenarios presented here.

Even if the price of natural gas is doubled in the *High-Price Natural Gas* case, gas generation provides 26 percent of WECC electricity in 2020. If upstream emissions from the natural gas supply chain are included, the share of natural gas actually increases in this timeframe to 39 percent. The higher emissions from natural gas result in a need to increase wind electricity production in order to meet the emissions cap. However, wind's intermittency necessitates additional flexibility, which results in a displacement of relatively inflexible, carbon-intensive coal generation by more maneuverable gas generation and an increase in the electricity generated from gas relative to the *Reference* scenario. It is a combination of wind and gas deployment that replaces coal electricity in the *Methane Leakage* scenario.

The failure to implement energy efficiency measures in the *Limited Efficiency* scenario means that a higher overall load must be met in 2020: 17 percent more electricity is generated relative to the *Reference* scenario. Similarly to the *Methane Leakage* scenario described above, the 2020 *Limited Efficiency* system must increase electricity generated from wind and gas while reducing the total contribution of coal in order to both remain within the cap and ensure that the system has sufficient flexibility to compensate for the variability of wind output. If efficiency measures are not implemented as in the *Limited Efficiency* scenario, the extra demand is met by an expansion of natural gas capacity and an associated reduction in the share of coal (which has higher emissions than natural gas) that allows the system to stay within the carbon cap. Finally, in the *Limited Hydro* scenario in which hydro energy is less available than in the *Reference* case, the energy deficit is made up with gas generation, which provides 39 percent of electricity, but coal electricity production must also be decreased in order to meet the carbon cap.

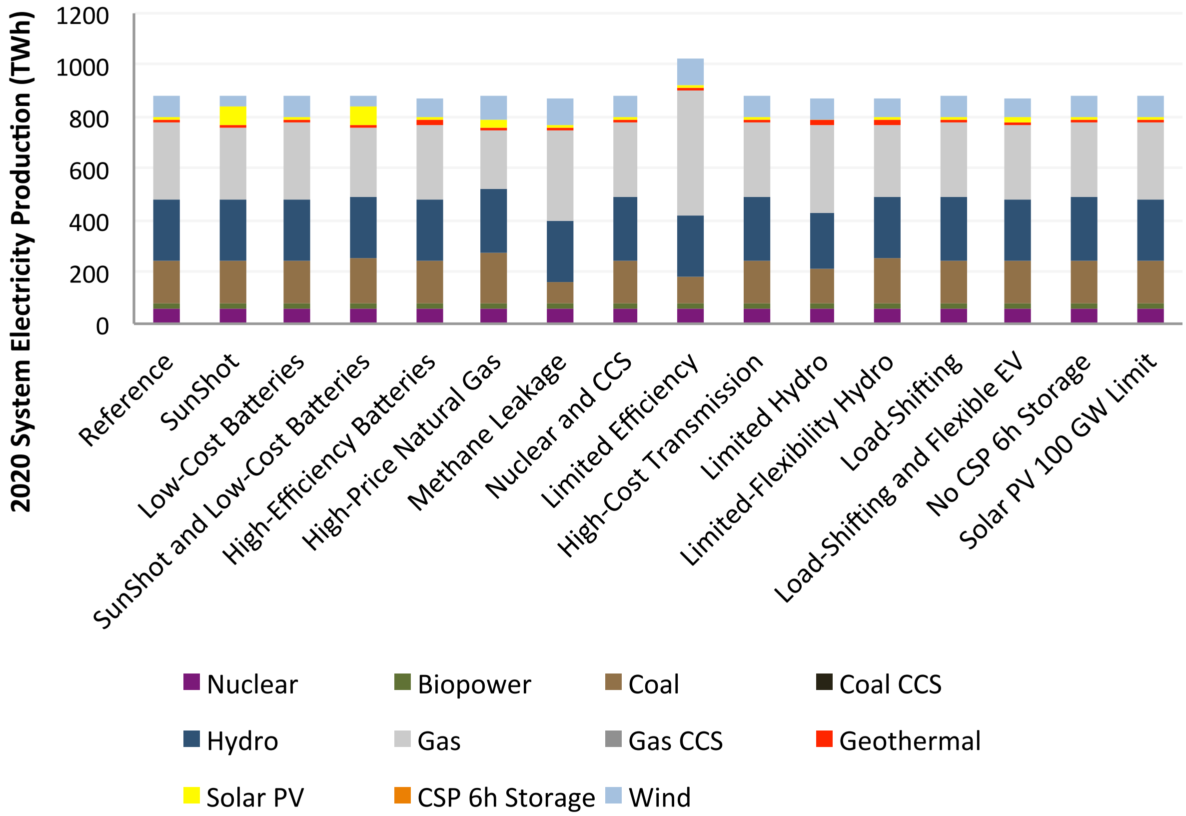


Figure 9. WECC system energy mix in 2020 by scenario.

Figure 10 shows system capacity in 2020 across scenarios. No new storage is deployed in any of the scenarios in this timeframe. The combined output of wind and solar PV generation is between 10 and 14 percent of all electricity generation in the scenarios studied in 2020. In the systems created by SWITCH, little need for storage exists as flexible natural gas and hydro generation are deployed widely and can compensate for these levels of wind and solar generation. At this penetration of wind and solar, limiting the ability of hydropower to follow load in the *Limited-Flexibility Hydro* scenario still does not effect storage deployment and results in almost no changes to the electricity mix, suggesting sufficient flexibility still exists within the system that is more cost-effective than the storage technologies available in this timeframe.

It is important to note that the results presented here do not consider storage devices that are designed for shorter durations and applications mostly in the regulation and other ancillary service markets. Frequency regulation has been shown to provide the most value for storage devices capable of responding quickly to frequency signals ("Cost-Effectiveness of Energy Storage: Application of the EPRI Energy Storage Valuation Tool to Inform the California Public Utilities Commission Proceeding R. 10-12-007" 2013). Rather, I only seek to model storage with duration of several hours that can shift energy in bulk and provide energy arbitrage over the course of the day, moving energy from times of load net demand and low prices to peak net load hours when prices are high. The results presented here suggest that three factors prevent deployment: 1) the cost of storage, which remains high, 2) the losses associated with storing energy, necessitating higher total electricity production, and 3) the availability of other low-cost sources of flexibility such as existing hydropower and low-cost natural gas generation. Little bulk energy storage can be deployed cost-effectively for energy arbitrage in the 2020 timeframe. This conclusion may change if the amount of flexibility from both hydropower and natural gas is reduced, but holds true across the scenarios presented here including the *High-Price Natural Gas* scenario, which has lower levels of natural gas use (26 percent of energy as opposed to 33 percent in the *Reference* scenario) and the *Limited-Flexibility Hydro* scenario, which reduces the ability of hydropower to follow load.

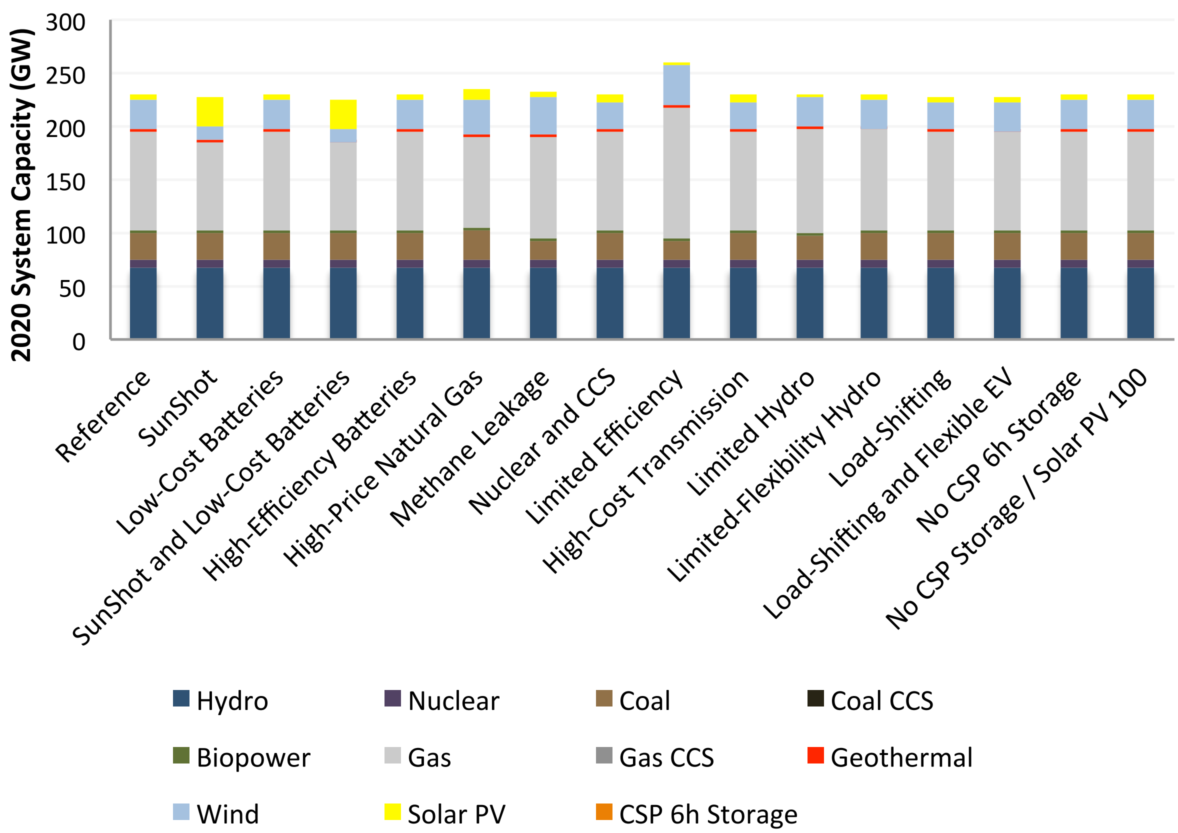


Figure 10. WECC system capacity in 2020 by scenario.

3. Electricity Production and Generation Capacity in 2030

By 2030, natural gas replaces most coal in the fuel mix across scenarios (Figure 11) and coal capacity is largely retired (Figure 12). If natural gas prices remain as projected and supply chain methane leakage is either found to be negligible or minimized through technical fixes ("Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries" 2014; "Clearing the Air: Reducing Upstream Greenhouse Gas Emissions from U.S. Natural Gas Systems" 2013; Alvarez et al. 2012), natural gas would likely be a dominant source of electricity in the 2030 timeframe. The fraction of electricity produced from natural gas is between 42 and 52 percent in these scenarios. If the price of natural gas is doubled as in the *High-Price Natural Gas* scenario, the optimization finds it more cost effective to increase the build-out of wind and geothermal energy capacity, reducing the share of natural gas to 30 percent of electricity production. In this case, power system emissions in 2030 are at 52 percent of 1990 levels, below the carbon cap target of ~70 percent of 1990 levels in the 2030 timeframe. The effect of methane leakage on the system energy mix is similar to that of increasing the price of natural gas, but emissions are higher due to the higher carbon intensity of natural gas resulting from the assumed upstream leakage of methane.

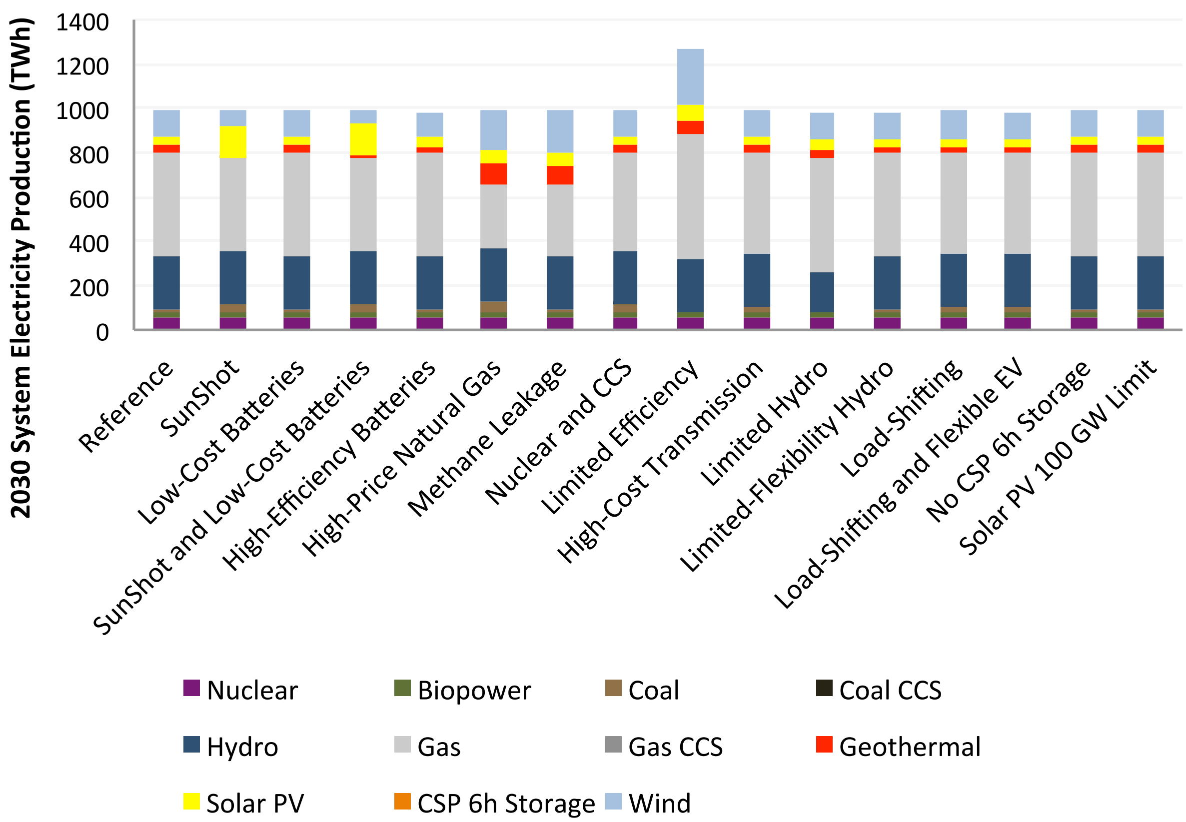


Figure 11. WECC system energy mix in 2030 by scenario.

Deployment of wind generation 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 of wind deployment and the share of natural gas is reduced from 47 percent in the *Reference* case to 42 percent in the *SunShot* scenario. The combined energy share of wind and solar PV in 2030 ranges between 16 and 25 percent in the scenarios investigated. The largest share is needed in the Limited Efficiency scenario, which requires deployment of 88 GW of wind generation and 27 GW of solar PV to help meet rising demand while containing greenhouse gas emissions.

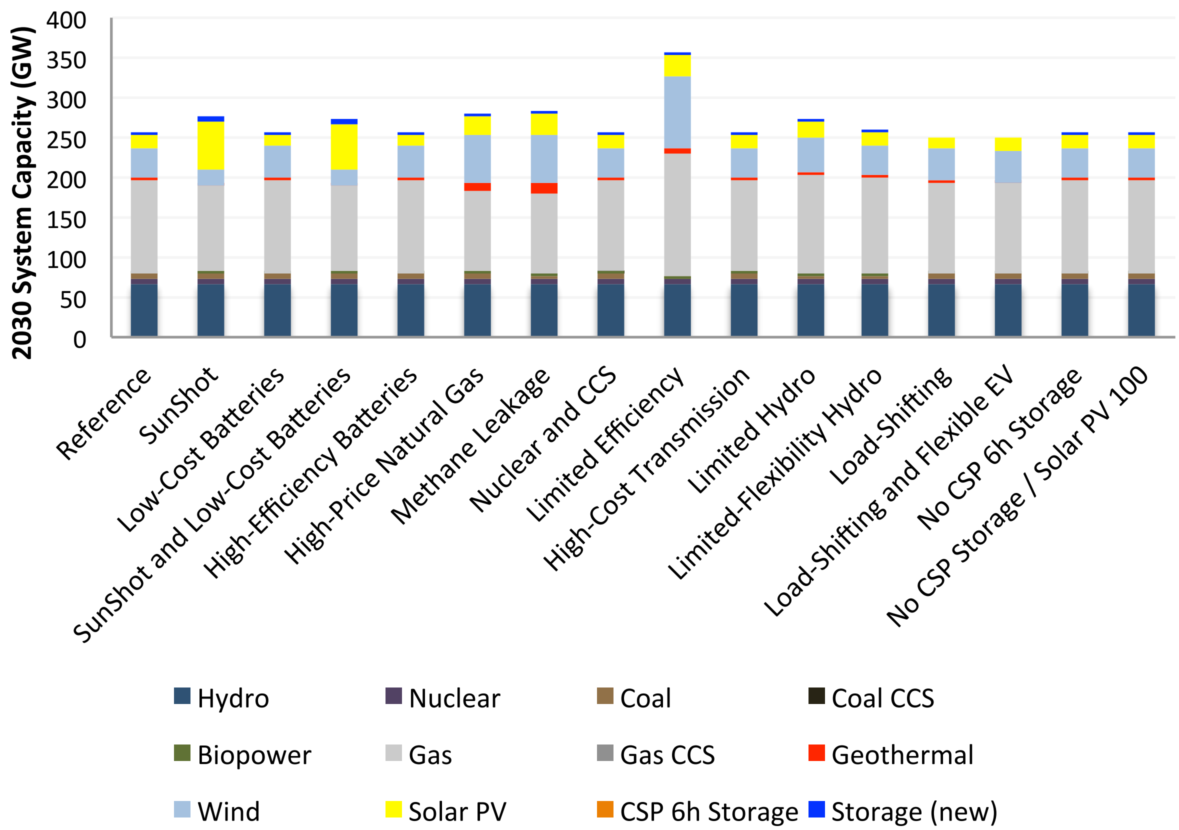


Figure 12. WECC system capacity in 2030 by scenario.

4. Storage Deployment in 2030

By 2030, deployment of new storage begins to take place in most of the scenarios investigated here, almost doubling current storage power capacity in some cases (Figure 13). The total amount installed varies across assumptions about the rest of the system.

In the *Reference* scenario, about 700 MW of CAES with 7-8 hours of full-load duration are installed. The availability of cheaper batteries in the *Low-Cost Batteries* scenario does not result in their deployment at a large-scale in this timeframe, with 240 GW of battery capacity installed in the *Low-Cost Batteries* scenario in 2030. This battery capacity replaces CAES capacity relative to the *Reference* case, but total storage capacity is the approximately the same between the two scenarios, suggesting that the system has sufficient flexibility available at a cost lower than what the storage technologies can provide. Increasing battery round-trip efficiency from 75 percent to 90 percent in the *High-Efficiency Batteries* scenario while keeping costs the same as in the *Reference* case does not result in deployment of batteries in the 2030 timeframe.

The most storage in 2030 is installed in the *SunShot* scenario: 5 GW of compressed air energy storage with 8-hour duration are deployed largely in Arizona where large solar installations are built in this timeframe. As with default solar costs, the availability of low-cost batteries in addition to SunShot solar costs does not result in deployment of additional storage, but simply in the substitution of batteries for CAES (less than half a GW of batteries with ~5-hour duration), suggesting CAES has better economics in the 2030 timeframe as modeled here. Unlike batteries, CAES does produce emissions; however, batteries are modeled as less efficient than CAES, so require additional energy generation, and CAES also benefits from the low price of natural gas in this timeframe.

About 5 GW of storage are also installed in the *Limited Efficiency* scenario, almost all of it CAES with between 7 and 12 hours of storage. If efficiency measures are not deployed, additional load must be met, but the carbon cap cannot be relaxed, resulting in earlier deployment of large capacities of wind and solar, which impose additional flexibility requirements on the WECC power system by 2030. Deployment of storage in the 2030 timeframe may also be needed if other sources of flexibility in the system are more limited than assumed in the *Reference* scenario. Limiting either the total energy availability of hydro or its maneuverability results in more than 3 GW of CAES deployment while a decreased use of natural gas due to higher prices or methane leakage is accompanied by the installation of more than 2 GW of CAES. The role that storage plays in these systems is discussed below.

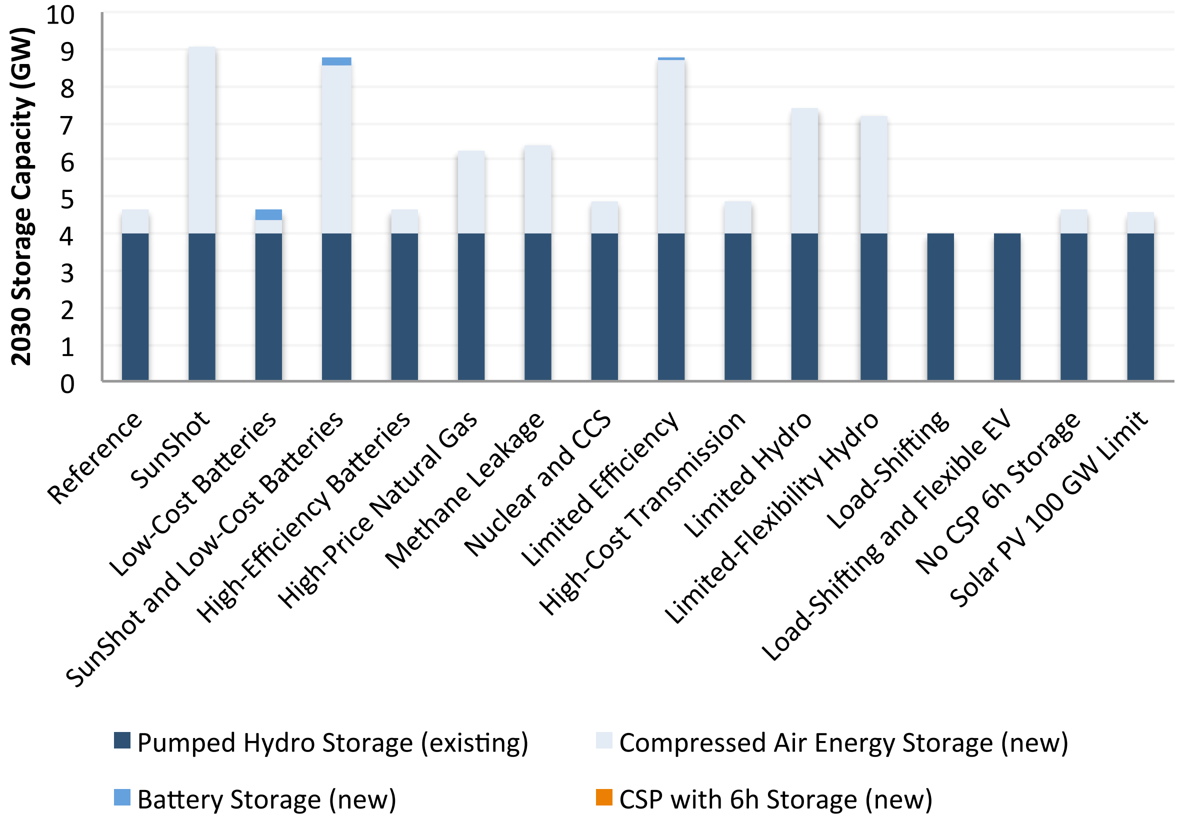


Figure 13. Storage deployment in the WECC in 2030 by scenario.

5. System Unit-Commitment

To understand the reasons for the differing levels of storage deployment across scenarios, I explore the system unit-commitment to understand how storage is used in each case. The infrastructure decisions of the main SWITCH investment optimization are fixed and the system is then optimally committed over a full year of time-synchronized load and renewable output data. Each day of the year is optimized on its own. All unit-commitment figures shown here are based on results from the secondary unit-commitment check phase following the SWITCH investment optimization.

5.1. Reference Scenario

In the *Reference* scenario in 2020, coal provides 19 percent of WECC electricity and a third is supplied by gas generation. Existing pumped hydro storage is used regularly, especially in the summer months, to shift energy from the nighttime to the daytime peak (Figure 14). Most coal generation is replaced by gas by 2030 and an expansion in wind and solar capacity helps to meet the rise in demand.

By 2030, gas dominates the WECC electricity mix, providing 47 percent of electricity while wind and solar PV contribute 12 percent and 4 percent respectively. About 700 MW of CAES are installed in the *Reference* scenario, considerably less than in several other scenarios explored here. Storage in the 2030 *Reference* scenario system is used less in 2030 than in 2020 during the spring months and in parts of the summer (Figure 15). Of note is in particular that storage is inactive during the peak load times in July, even though peaker gas combustion turbines are used extensively in the second half of the month (Figure 16).

On the median day in July, storage is used according to a pattern of nighttime charging when net load is low and CCGTs are the marginal generator, and releasing energy in the afternoon and evening hours when load increases, solar is not available any more, and net load is at its peak for the day requiring the use of the high-marginal-cost combustion turbines (Figure 17, top panel).

This dispatch pattern is typical for much of the summer. However, in late July in this scenario, the pattern of storage use changes (Figure 17, bottom panel). On the peak net load day in July, which is also the overall peak net load day for 2030, combustion turbines are used throughout the day to help meet an increase in load. Nighttime load during this 10-day period in July remains high and wind dies down, resulting in a high net load during the night as well during the day. The system is stressed throughout the day and there is as scarcity of low-marginal-cost excess energy available for storage to shift to other times of the day. As a result, storage is inactive during this period. Combustion turbines are run throughout and are the marginal generator for many consecutive hours, so no price difference exists for storage to take advantage of and provide energy arbitrage. (All combustion turbines are modeled as having the same heat rate, so have the same marginal cost except for regional variation in natural gas prices due to different fuel extraction and transportation costs.) While combustion turbine could be run at night and the energy stored for use during the day, the inefficiency of the storage process means that a larger price difference than seen in this scenario is necessary for storage to be active. CAES round-trip efficiency is 82 percent, pumped hydro's is 74 percent, and batteries are at 75 percent in the *Reference* scenario, requiring the respective difference in energy price to justify storage use.

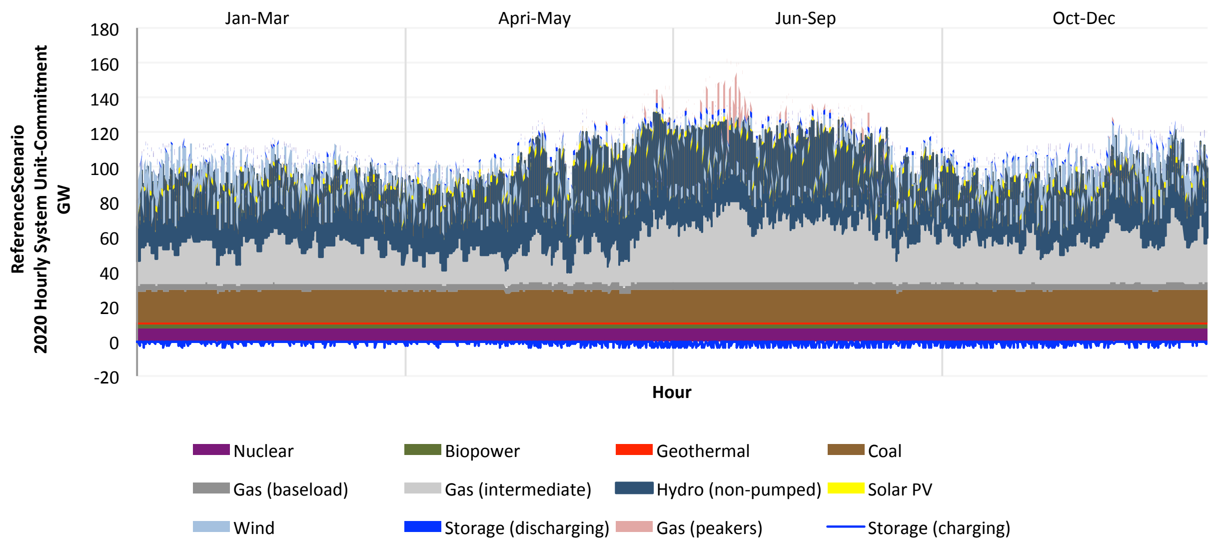


Figure 14. WECC System Hourly Unit-Commitment, Reference *Scenario, 2020.*

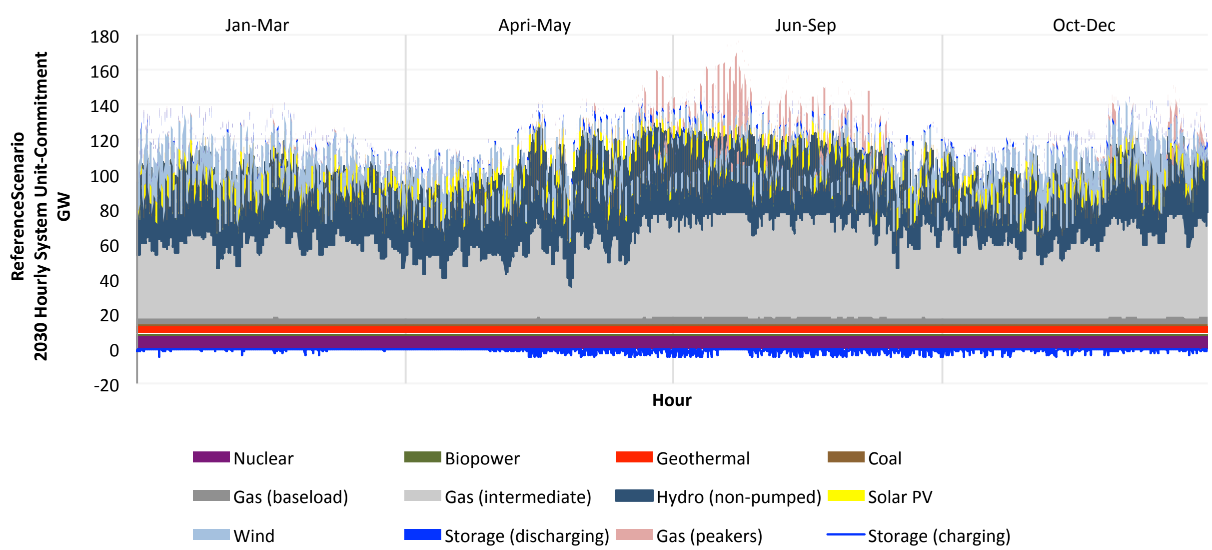


Figure 15. WECC System Hourly Unit-Commitment, Reference *Scenario, 2030.*

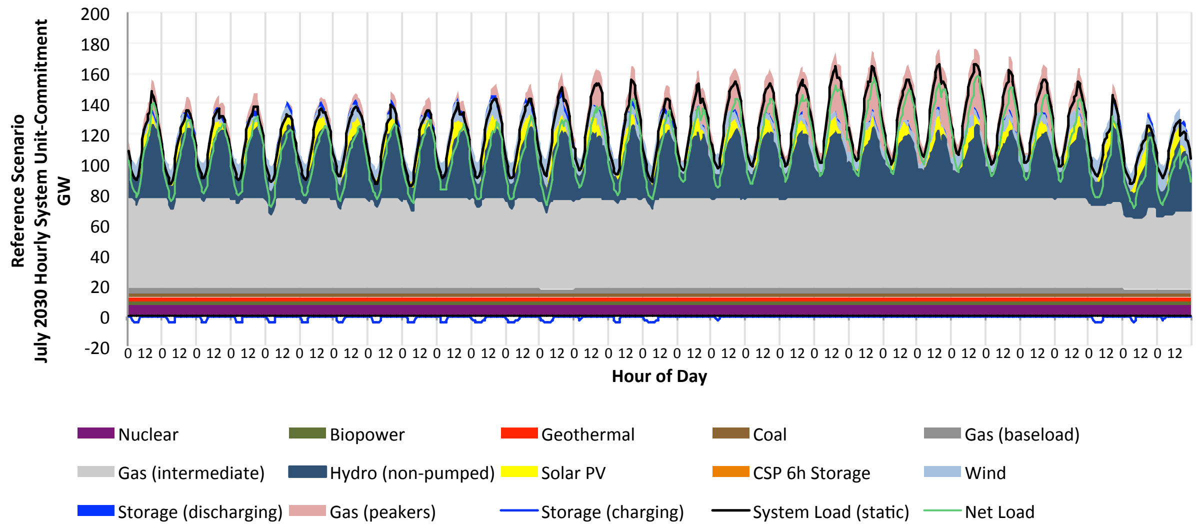


Figure 16. WECC System Hourly Unit-Commitment, Reference *Scenario, July 2030.*

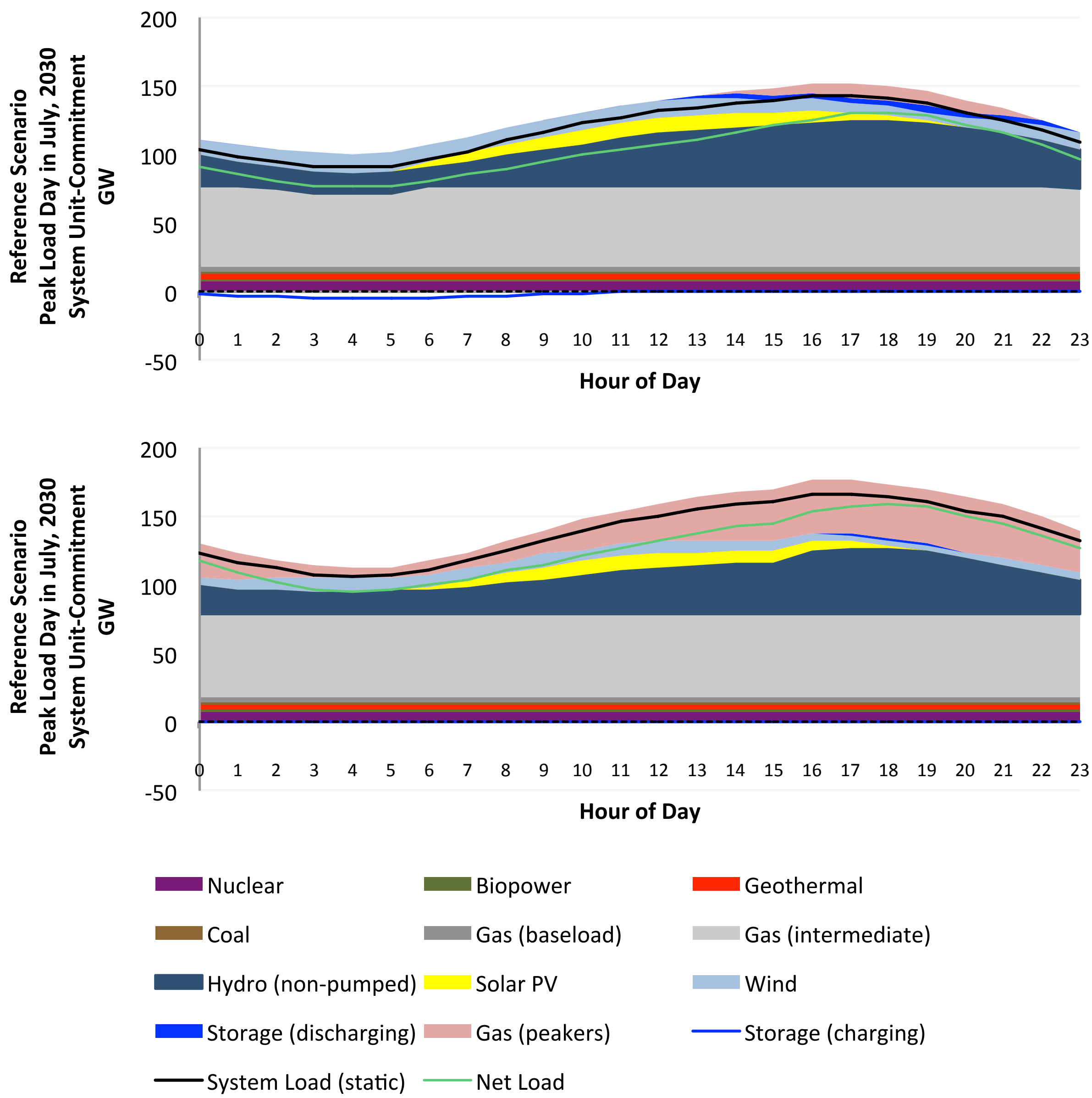


Figure 17. WECC system hourly unit-commitment on the median load day in July (top panel) and the peak net-load day (bottom panel) in 2030, Reference *Scenario*, 2030.

5.1. SunShot Scenario

The *SunShot* case has the most storage – about 5 GW of CAES with 8 hours duration – installed by 2030 of all scenarios investigated. In the *SunShot* scenario, large-scale deployment of solar PV takes place by 2030: 59 GW of solar PV are installed in that timeframe as opposed to 15 GW in the *Reference* case. The presence of this level solar PV on the power system results in changes to the typical system unit commitment schedule because of changes to the net load profile.

Unlike in the *Reference* scenario, storage in the *SunShot* scenario in 2030 is used throughout the year (Figure 18. The pattern of storage use changes relative to the *Reference* scenario and to present day: instead of charging at night, storage tends to charge in the morning when the net load is at its daily minimum as solar PV is producing energy at full output and load level is low (CCGTs are the marginal generator); storage then releases energy in the evening hours and at night when the sun has gone down and solar energy is not available while load is still high, resulting in net load reaching its daily peak and necessitating the startup of combustion turbines with high marginal cost (Figure 19, top panel). Even during the times of highest stress in late July, this charging pattern for storage is in place, although less excess low-marginal-cost energy is available in the morning during that period for storage to shift to the high-price times in the evening (Figure 19, bottom panel).

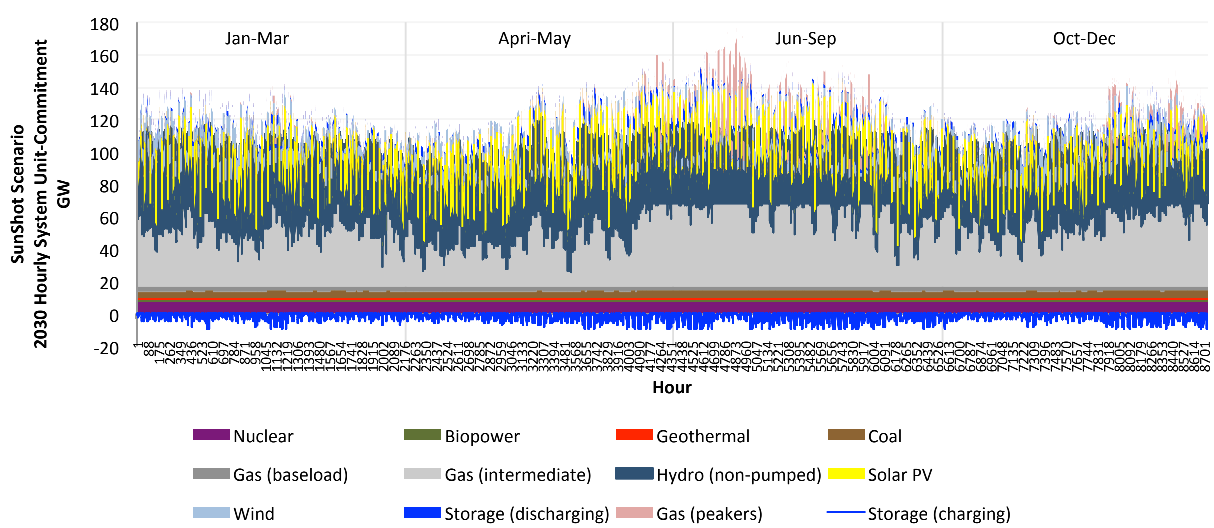


Figure 18. WECC System Hourly Unit-Commitment, SunShot *Scenario, 2030.*

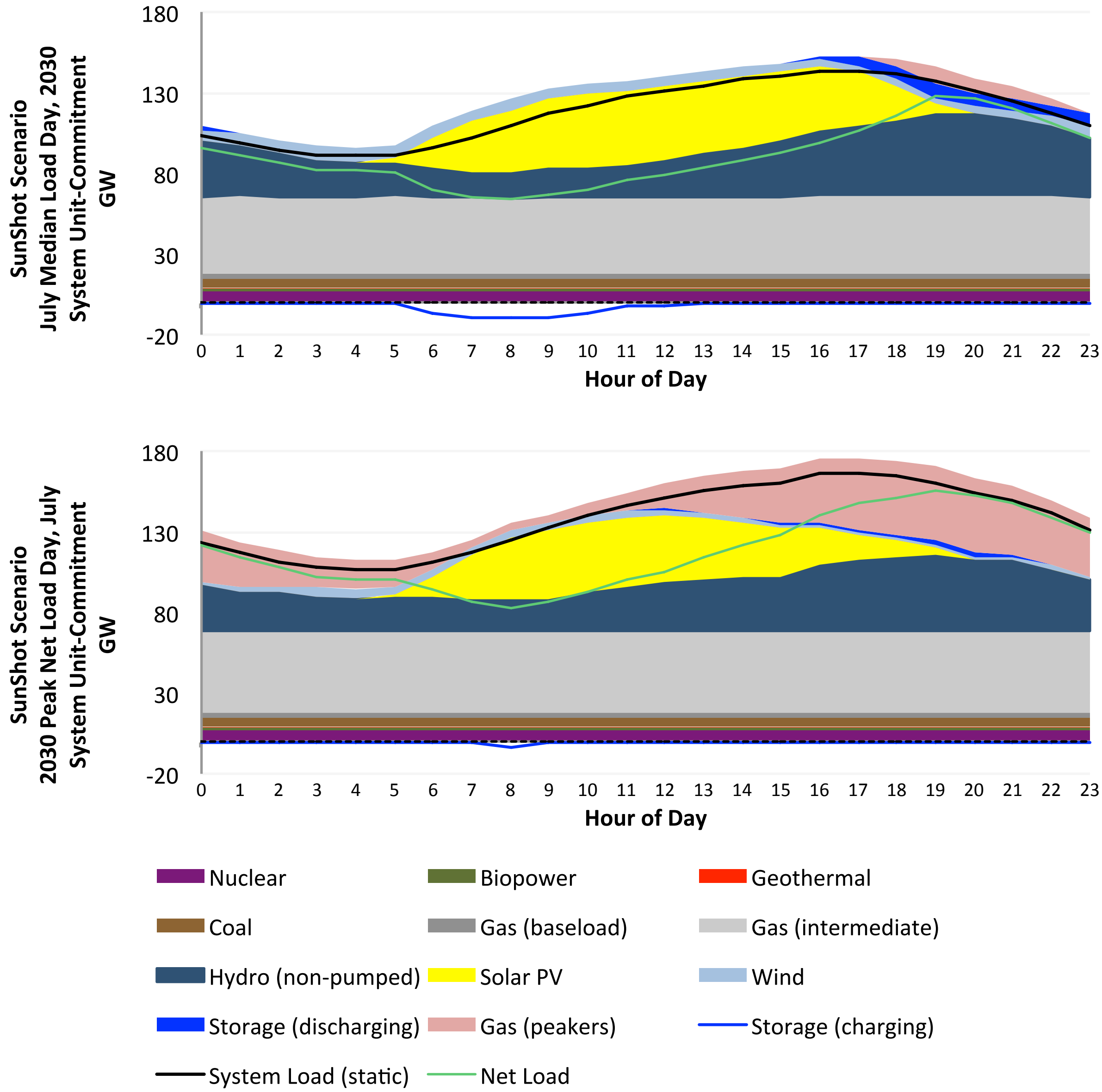


Figure 19. WECC system hourly unit-commitment on the median load day in July (top panel) and peak net load day (bottom panel) in 2030, SunShot *Scenario.*

V. System Flexibility Requirements in the Long-Term Timeframe

1. System Development Summary

By 2040, considerably more renewables are deployed in the *Reference scenario*. Wind has the most significant share and is installed across the WECC, with the largest capacities in the eastern WECC, Alberta, and California (Figure 20). Solar PV is deployed in California. CSP with storage is first installed in 2040. Geothermal potential is tapped out in this timeframe. By 2040, 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 interties are minimal.

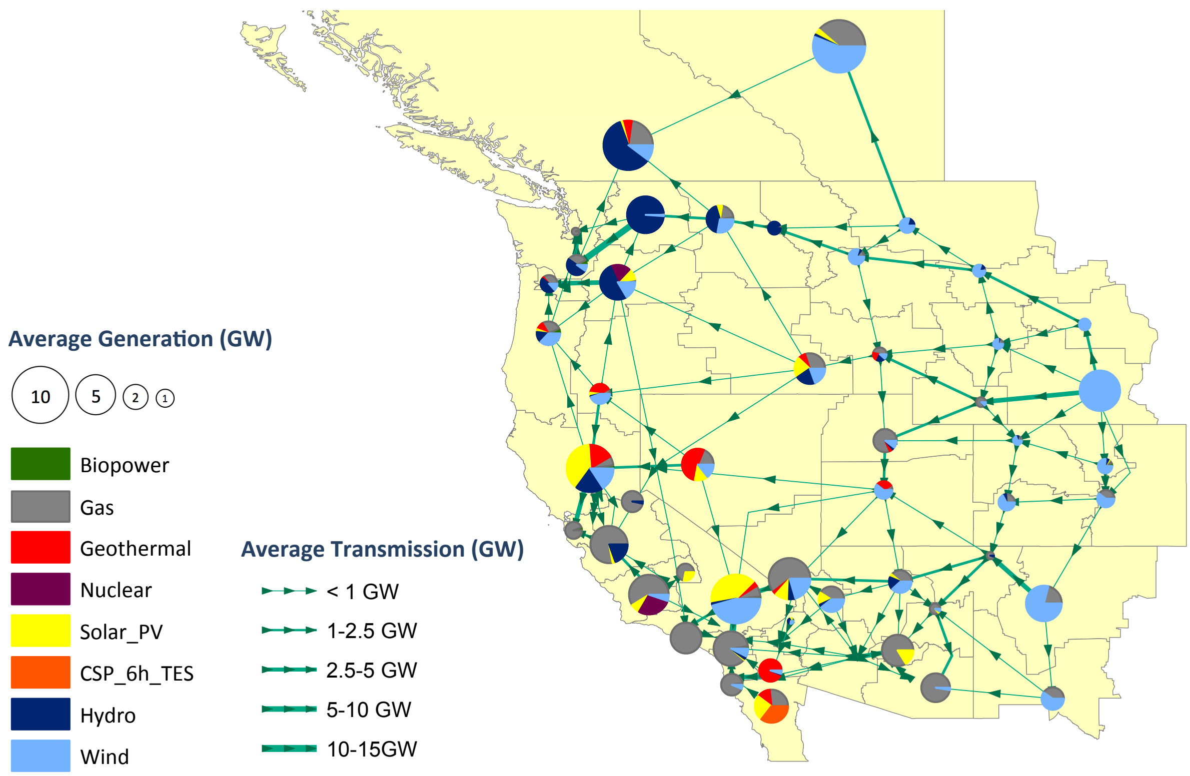


Figure 20. Map of average generation and transmission, Reference *scenario, 2040.*

These trends are continued and amplified in the 2050 timeframe (Figure 21). Large-scale flows of wind energy from east to west are a dominant feature of the *Reference* scenario. By 2050, the system is very reliant on CSP with storage deployed in the Southwest. The Pacific Northwest generates a mix of hydro, wind, and solar energy. Gas plants are a large component of local generation in California and Arizona as well as in Canada.

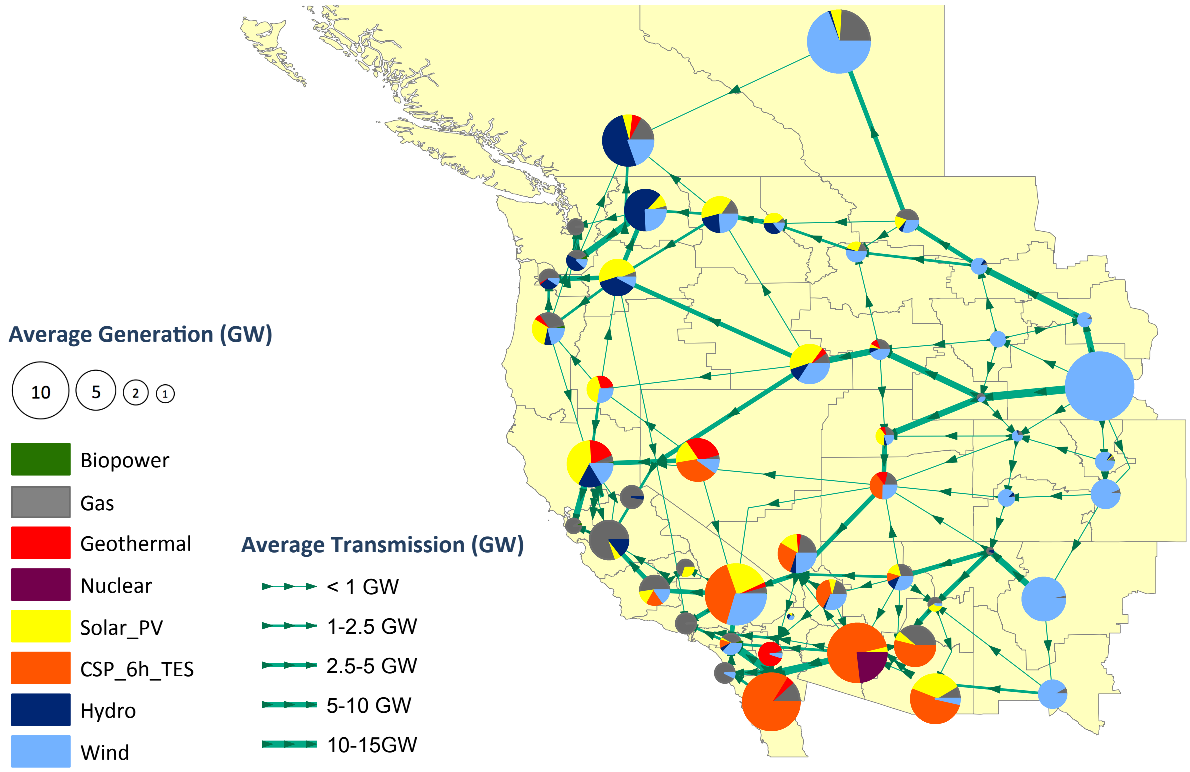


Figure 21. Map of average generation and transmission, Reference *scenario, 2050.*

2. Electricity Production and Generation Capacity in 2040

As the carbon cap becomes more and more stringent over time after 2030, the amount of natural gas that can remain in the system becomes limited. Across scenarios, natural gas provides between 300 and 330 TWh yearly in the 2040 timeframe, equivalent to about a quarter of total electricity production in most scenarios (Figure 22). In the *Limited Efficiency* scenario, the additional load is met with an expansion in the capacity of wind, solar PV, and CSP with storage relative to the *Reference* case (Figure 23). CSP with storage appears in the system for the first time in 2040, but PV is still the most widely deployed solar technology across scenarios in this timeframe. The largest PV deployment takes place under the assumptions of the *SunShot and Low-Cost Batteries* scenario, in which solar PV deployment reaches 120 GW by 2040. In the *Nuclear and CCS* scenario, new nuclear is first installed in 2040, with 14 GW of additional nuclear capacity added. Carbon-free, baseload geothermal energy is deployed across scenarios, tapping out the available potential by 2040 in all by the two *SunShot* scenarios.

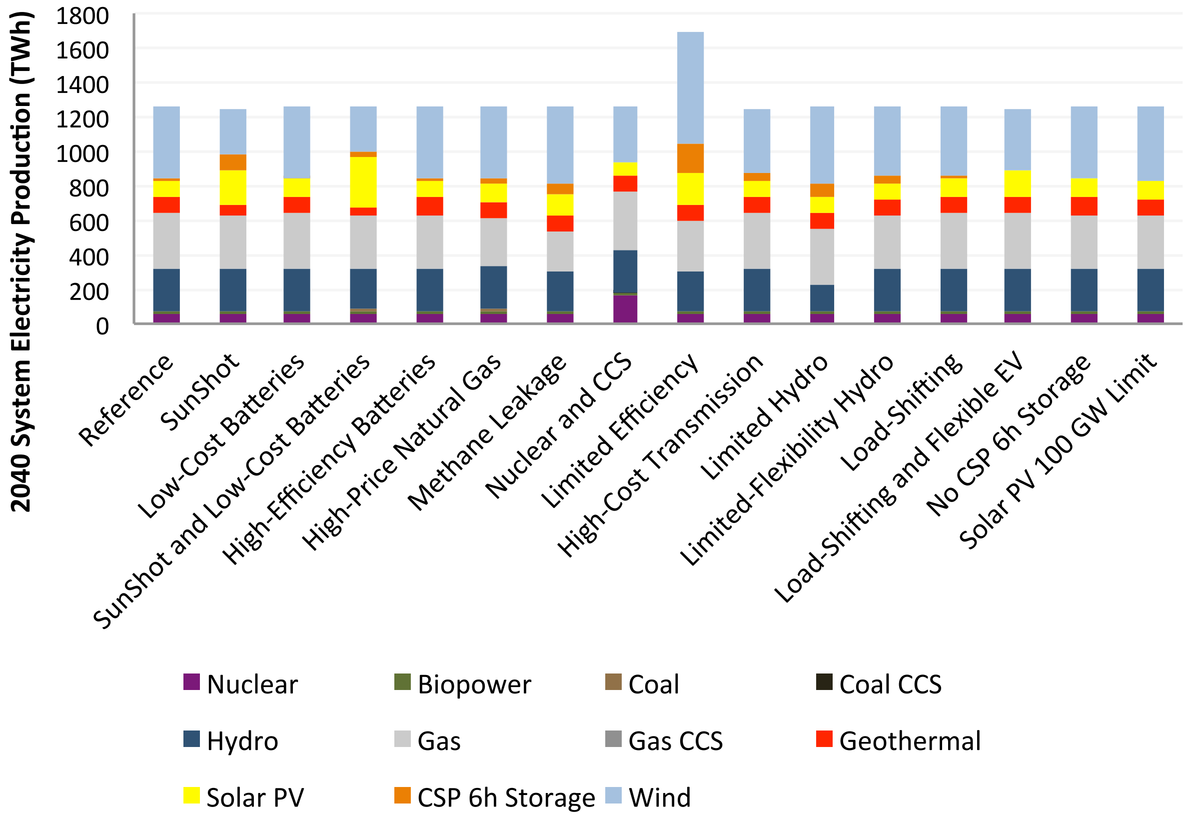


Figure 22. WECC system energy mix in 2040 by scenario.

New storage capacity in the 2040 timeframe varies between 4 GW in the *Load-Shifting and Flexible EV-Charging* scenario and 32 GW in the *SunShot and Low-Cost Batteries* scenario. In the latter, storage capacity is almost 10 percent of total system capacity in 2040 (Figure 23). In most scenarios, new storage deployment is between 10 and 15 GW, or approximately 3 percent of total system capacity.

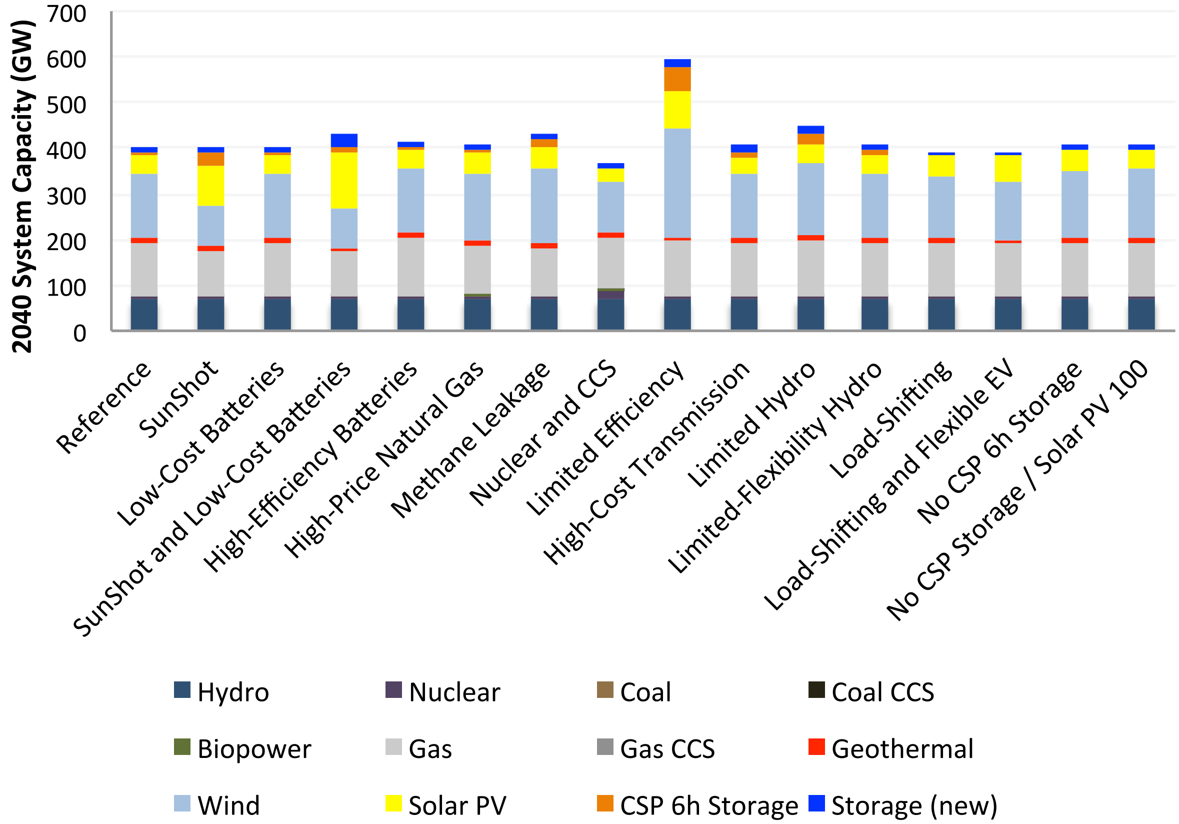


Figure 23. WECC system capacity in 2040 by scenario.

3. Electricity Production and Generation Capacity in 2050

Several of input parameters varied here that make a difference for the system energy and capacity mix in the 2030 timeframe do not have the same effect in the 2050 timeframe within the range of values tested in the scenarios investigated. For example, doubling the price of natural gas price limits the amount of natural gas generation in the system in 2030, but does not make a difference for the composition of the system in 2050 (costs do increase). In the long term, it is the cap on carbon emissions that becomes the determining factor for the amount of natural gas that the system can utilize. Under a strict carbon constraint, natural gas is very valuable to the system as it provides flexible generation that can both be ramped quickly and be available at all times of the year as needed. As a result, doubling the price of natural gas in the *High-Price Natural Gas* scenario does not effect changes in the generation mix.

CSP with storage, which first appears in the generation mix in 2040, is deployed widely by 2050 across scenarios. It outcompetes PV in the *Reference* scenario, even though it is more expensive on a levelized cost basis. This suggests that its dispatchability relative to PV is valuable to the power system. If instead low-cost batteries are available to provide flexibility, as in the *Low-Cost Batteries* scenario, PV becomes the dominant technology. In the *Reference* case, 120 GW of CSP-TES and 70 GW of solar PV are deployed, and 20 GW of new storage are also installed; in the *Low-Cost Batteries* scenario 170 GW of solar PV and 80 GW of CSP with storage are deployed as well as 80 GW of new storage installations. Similarly, if low-cost flexibility is available in the form of demand response and flexible charging of electric vehicles, the ratio of solar PV to CSP-TES capacity deployment increases. The availability of SunShot solar technologies increases both the capacity of PV and of CSP-TES relative to the *Reference* scenario.

If new nuclear builds are allowed, the 2050 system is dominated by nuclear generation, which outcompetes the other low-carbon baseload option in the *Nuclear and CCS* scenario: carbon capture and sequestration of emission from natural gas and coal plants. In this scenario, nuclear is assumed to be less expensive than CCS, and it has zero emissions whereas the capture efficiency for coal and natural gas CCS plants is assumed to be 85 percent, resulting in some emissions from CCS plants. At the costs modeled here, nuclear also outcompetes other zero-carbon generation options. A total of 85 GW of nuclear power are deployed by 2050, providing 43 percent of all electricity produced in the *Nuclear and CCS* scenario. However, little technological progress takes place for renewable technologies in the *Nuclear and CCS* scenario: wind costs stay at present-day levels and solar costs decline very slowly through 2050. In addition, to become a dominant component of the 2050 power system, nuclear power would have to achieve the costs assumed here and avoid cost overruns as well as overcome public opposition and concerns about the safety of nuclear waste disposal and the possibility of nuclear proliferation.

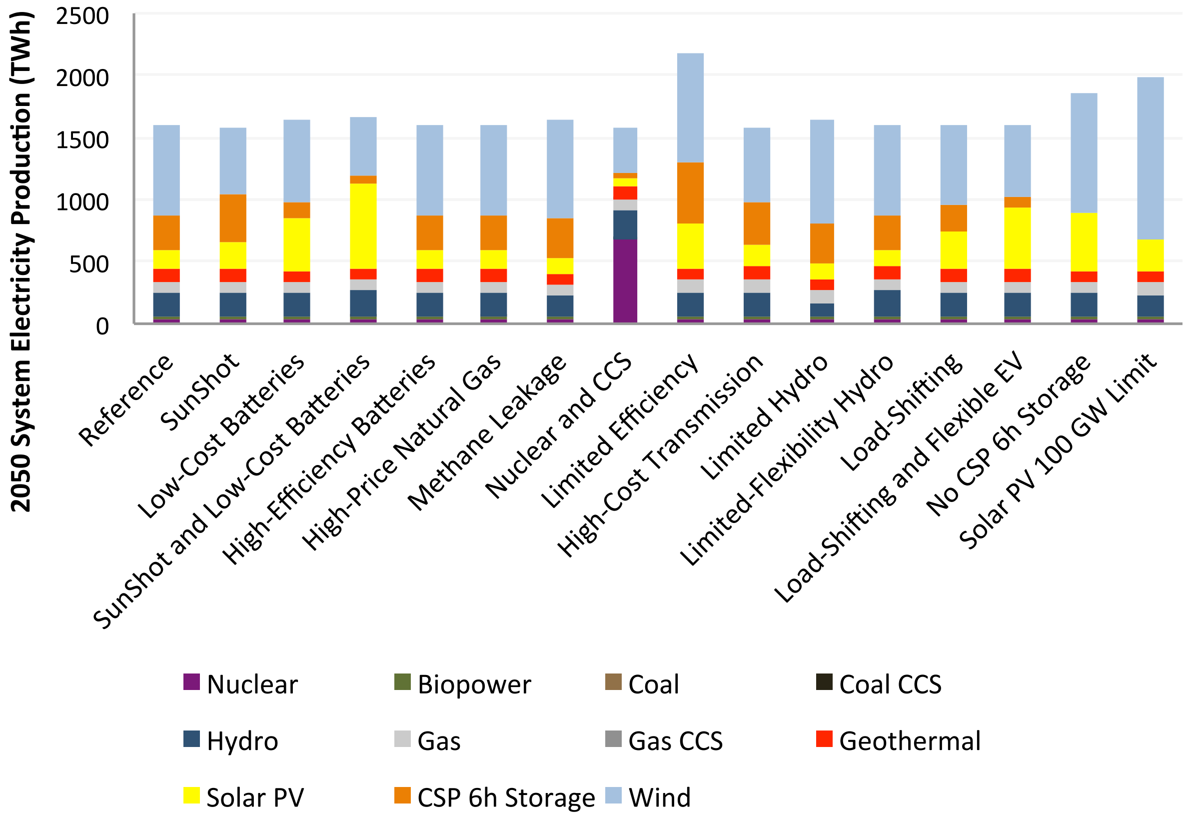


Figure 24. WECC system energy mix in 2050 by scenario.

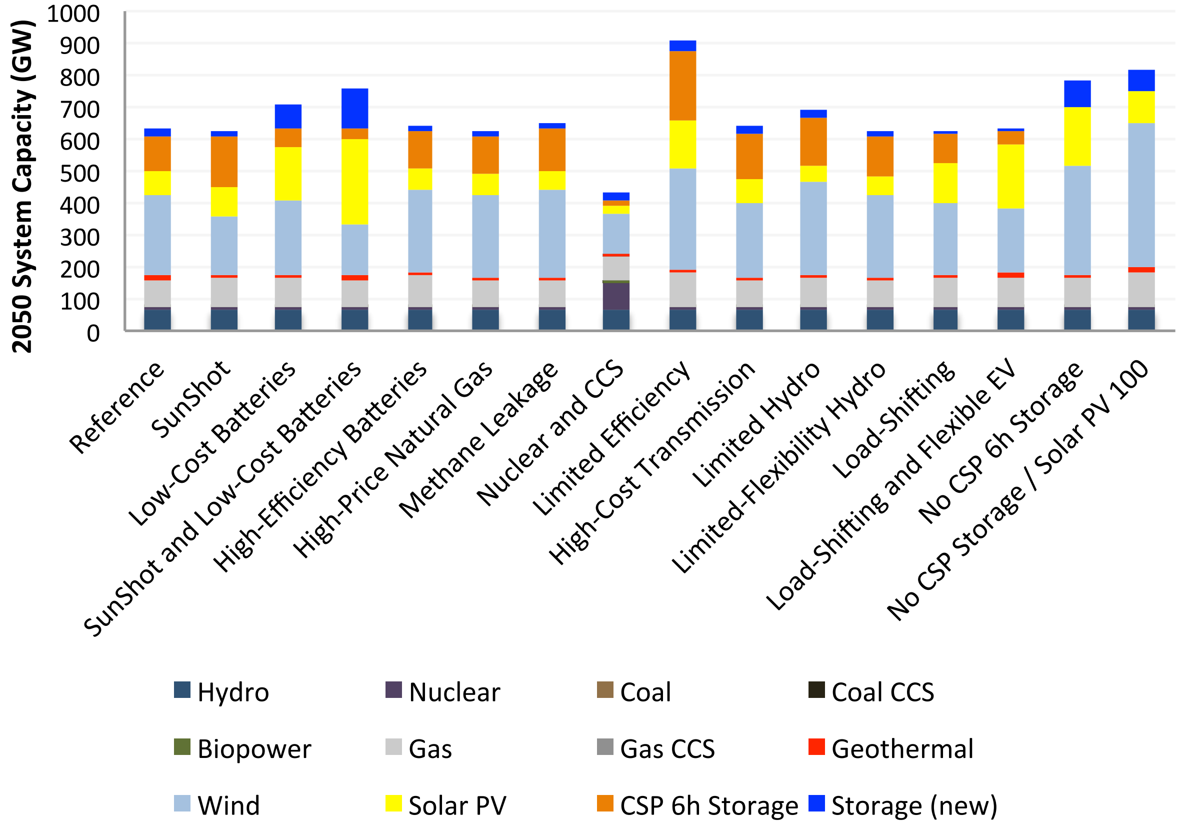


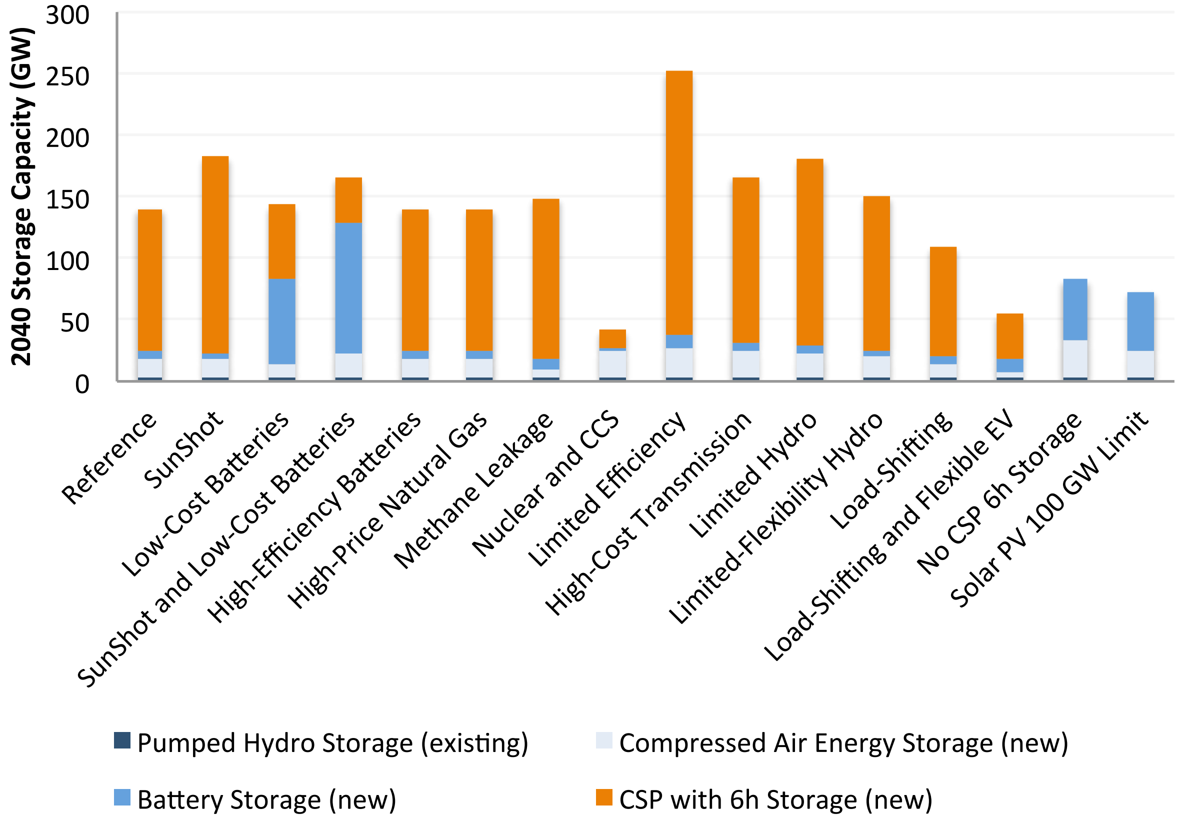
Figure 25. WECC system capacity in 2050 by scenario.

4. Storage Deployment in 2040 and 2050

Storage deployment reaches power capacities in the multi-GW scale in most scenarios by 2040 (Figure 26) and by 2050 storage plays a pivotal role in the WECC power system across the scenarios explored here (Figure 27). 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, thermal energy storage deployed at CSP plants is the dominant storage technology in 2050. Note that TES is different from other storage technologies modeled here in that it does not store electricity from the grid; rather, it stores thermal energy collected by the CSP plant for later conversion into electricity. In the *Reference* scenario, 120 GW of CSP with 6 hours of storage are installed. In addition, 14 GW of compressed air energy storage with an average of 10 hours maximum-load duration and 6 GW of batteries with an average of 2 hours of maximum-load duration are deployed. Limiting the amount of flexibility available to the system as in the *Methane Leakage*, *High-Cost Transmission*, *Limited Hydro*, and *Limited-Flexibility Hydro* scenarios results in higher deployment of storage technologies, with CSP-TES remaining dominant.

Unlike in the 2030 timeframe when the cost of batteries does not strongly affect their deployment level, 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 maximum-load duration of 6 hours. The largest battery deployment occurs in the *SunShot and Low-Cost Batteries* scenario, in which 110 GW of batteries with 6-hour duration are installed, largely in the Desert Southwest (Figure 28) where they support large-scale solar PV development.


2040 Storage Capacity (GW)
300
250
200
150
100
50
0
Reference
SunShot
Low-Cost Batteries
SunShot and Low-Cost Batteries
High-Efficiency Batteries
High-Price Natural Gas
Methane Leakage
Nuclear and CCS
Limited Efficiency
High-Cost Transmission
Limited Hydro
Limited-Flexibility Hydro
Load-Shifting
Load-Shifting and Flexible EV
No CSP 6h Storage
Solar PV 100 GW Limit
Pumped Hydro Storage (existing)
Compressed Air Energy Storage (new)
Battery Storage (new)
CSP with 6h Storage (new)

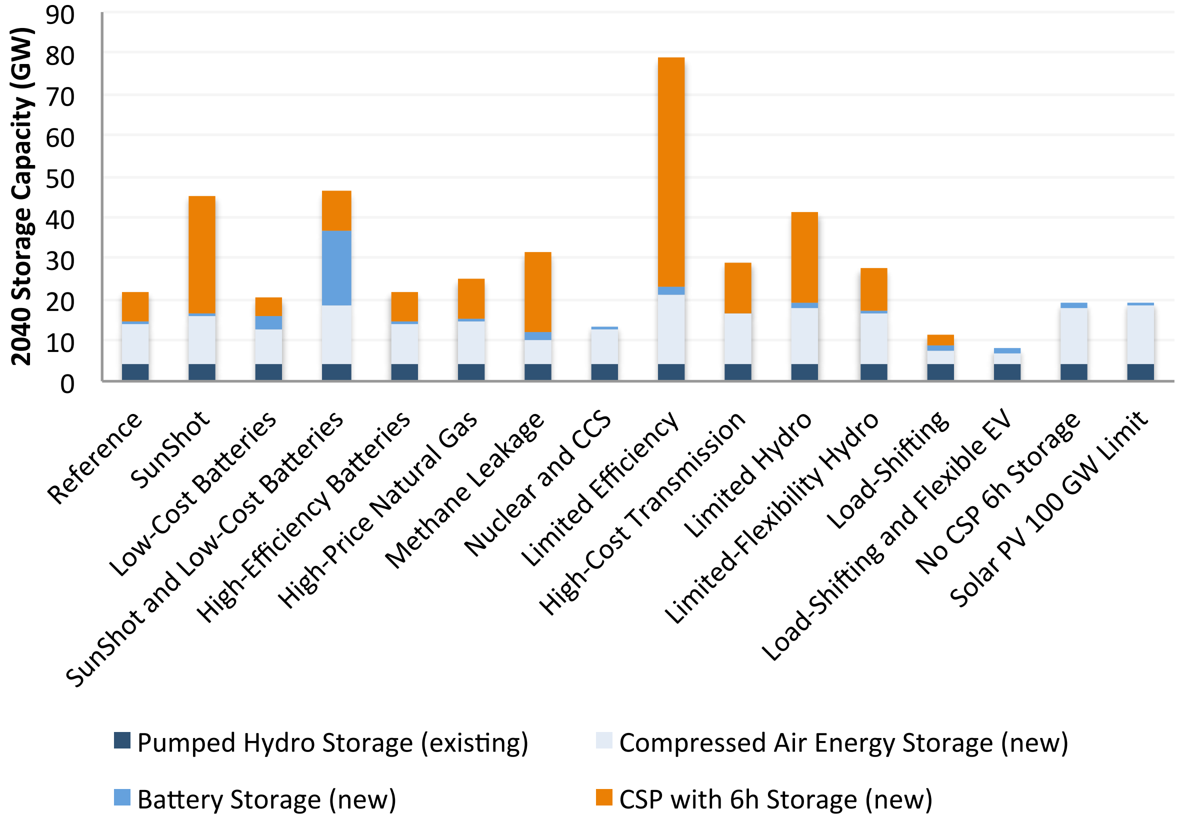


Figure 26. Storage deployment in WECC in 2040 by scenario.

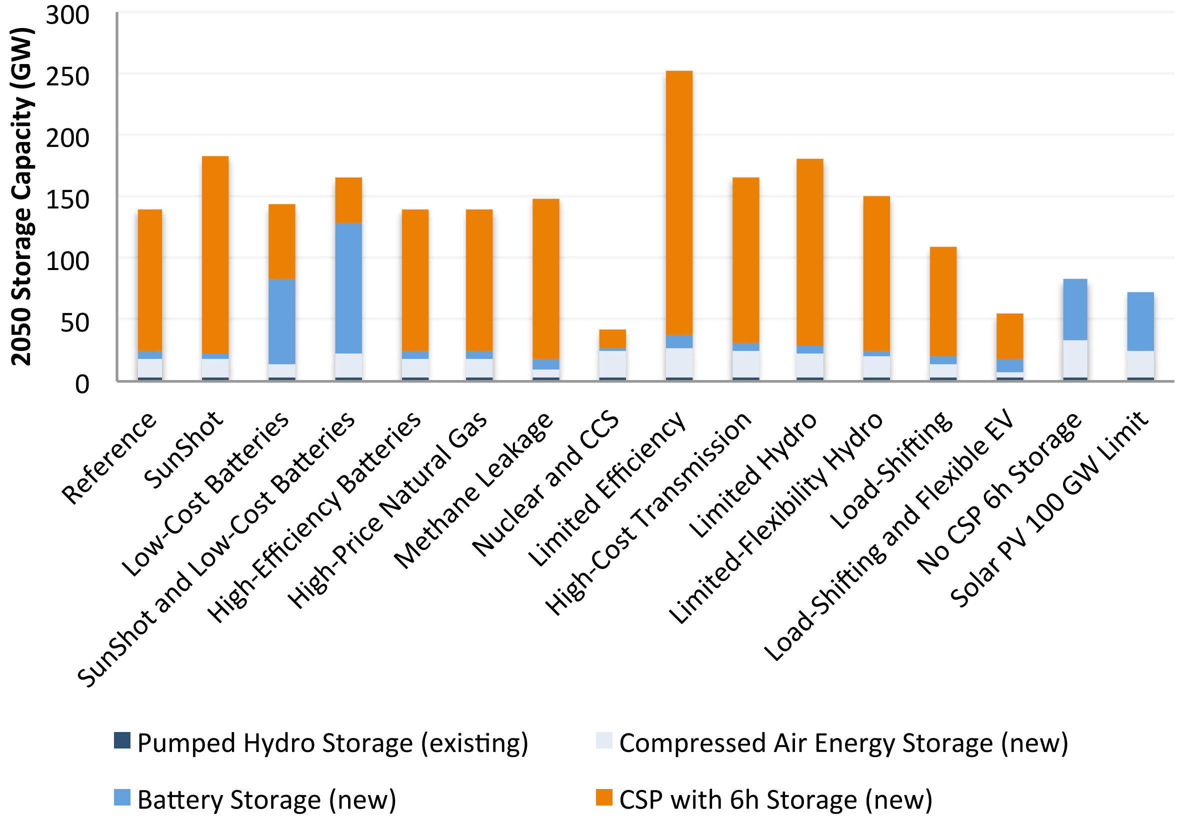


Figure 27. Storage deployment in the WECC in 2050 by scenario.

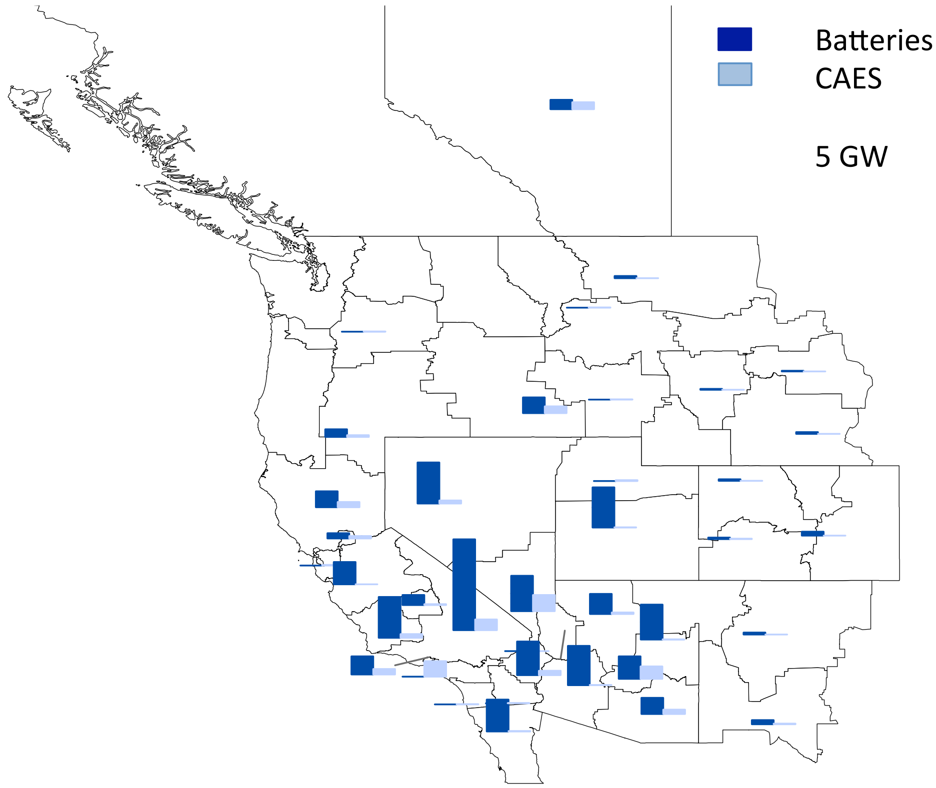


Figure 28. Map of storage deployment in the WECC, SunShot and Low-Cost Batteries Scenario*, 2050.*

5. System Unit-Commitment

5.1. Reference Scenario

Between 2030 and 2050, the unit commitment of the *Reference* scenario system experiences drastic changes relative to present day as a result of growth in total load, changes to the annual load profile due to efficiency implementation and electrification of heating and vehicles, and a stringent carbon cap that pushes carbon emissions from the system down to 85 percent below 1990 levels. In 2040, gas still provides 25 percent of total electricity production in the WECC in the *Reference* scenario, although it used much less outside of the summer months as load tends to be lower and wind more available during those times (Figure 29).

By 2050, the amount of gas in the system is reduced even more – to 6 percent of total electricity produced – as emissions allowances are very limited. As the system has to meet a more and more stringent carbon cap after 2030, considerable expansion in renewable capacity takes place accompanied by a build-out of 20 GW of storage by 2050. Wind dominates in this scenario, generating 45 percent of electricity in 2050, and CSP with 6h of storage and solar PV contribute 17 percent and 10 percent respectively. Geothermal generates an additional 6 percent, providing carbon-free, baseload electricity.

Large seasonal variations in how units are committed and load is met become a prominent feature of this system, with wind dominating electricity production in the winter and spring months while CSP with storage, intermediate gas generators, and gas peakers help to meet load in the summer. In January for example, the 2050 *Reference* system experiences consistently low net load levels, including frequent negative net load during the middle of the day when solar PV is at its peak (Figure 31). (The net load is calculated as the load minus intermittent generation, which includes wind and solar PV; CSP with storage is dispatchable within solar thermal energy availability constraints, so is not a part of the net load calculation.) CSP with storage provides energy at night and complements daytime PV generation, with their combined output staying relatively constraint throughout the month of January.

More than 250 GW of wind capacity are installed by 2050 in the *Reference* scenario, so a large amount of excess energy is consistently available in the winter and spring when wind output is high. SWITCH-WECC can only shift energy within the day, with each day optimized separately, and does not consider long-duration storage options such as large-reservoir pumped hydro storage or hydrogen storage. For many consecutive days, net load is low throughout the day with no high-stress times for the system, so storage is idle, as no opportunities to provide daily arbitrage exist. In the *Reference* scenario, 14 GW of CAES with an average of 10 hours of storage are installed as well as 6 GW of batteries with an average of less than 2 hours of storage, for a combined 152 GWh of total energy storage capacity. This amount is well below the total excess energy available during that period: the installed storage could charge cheaply on one of those days but would not have an opportunity to sell that energy back to the grid for many days as excess wind energy is available for many consecutive days during the winter and spring months, requiring many GW-days of storage to be fully utilized at a later time.

The 2050 Reference system unit-commitment in July (Figure 32) looks very different from that in January. In the summer months in the *Reference* scenario, wind output is low. This is partly compensated for by the availability of a large solar thermal resource in the summer. CSP with storage provides flexibility to the system, charging at night and releasing energy in the evening and at night when solar PV is not available. Deployment of CSP with storage in 2050 in the *Reference* scenario is 120 GW and it supplies 17 percent of total electricity production.

Pumped hydro, CAES, and battery storage in the July 2050 *Reference* system are used infrequently, on a few days when wind output is relatively high, providing some excess energy to shift to other times of the day. However, for most of the month, the *Reference* system is energy-constrained throughout the day. For example, for ~2 weeks in the second half of July, load reaches its peak summer levels, remaining high even at night, and the system must run intermediate gas generation at full output for many consecutive days as well as make heavy use of peaker gas generation in order to meet demand. During this period, the storage deployed in the 2050 *Reference* system is not used because lower-cost energy is not available at any point for many consecutive days (combustion turbines are the marginal generator for many consecutive hours). If long-duration storage were available and inexpensive, it 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.

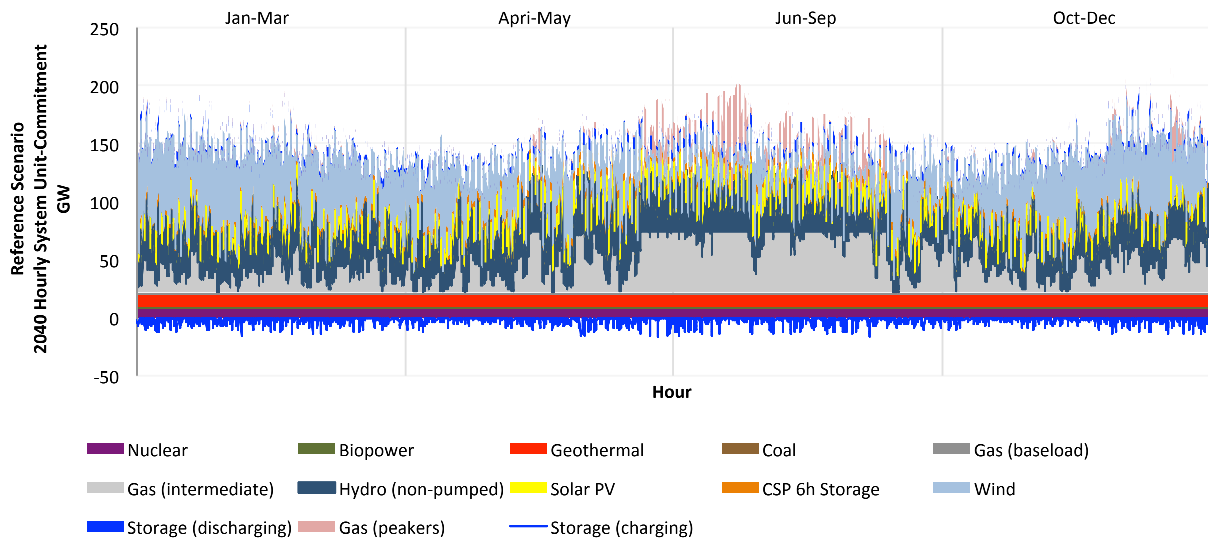


Figure 29. WECC System Hourly Unit-Commitment, 2040, Reference *Scenario.*

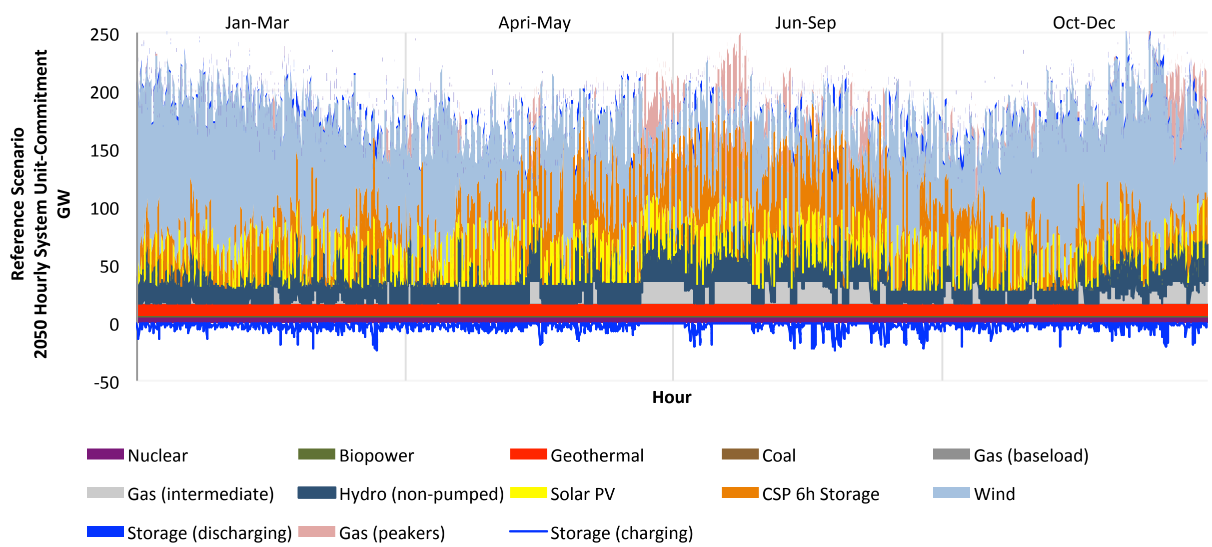


Figure 30. WECC System Hourly Unit-Commitment, Reference *Scenario, 2050.*

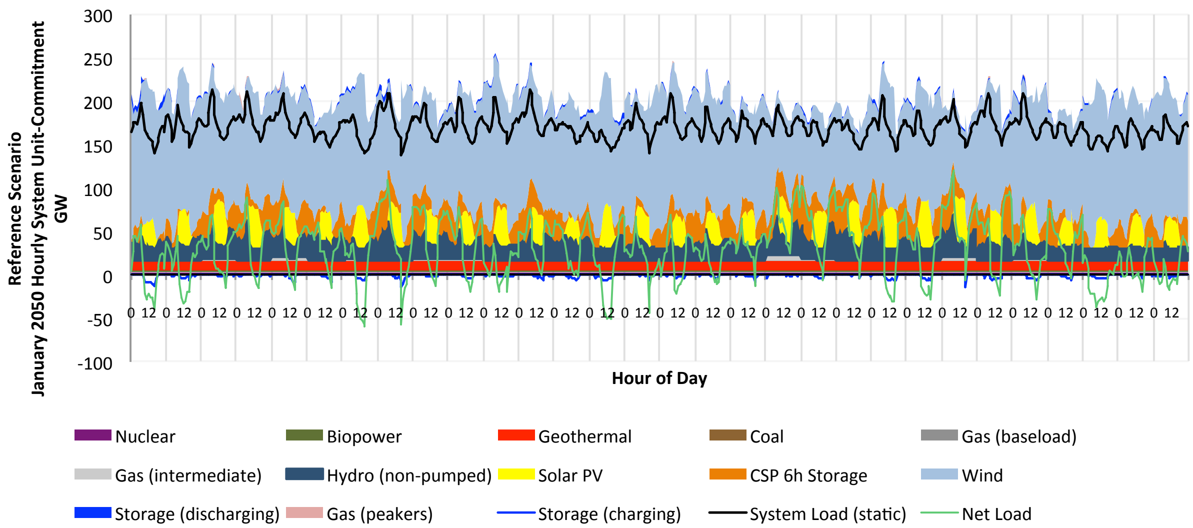


Figure 31. WECC System Hourly Unit-Commitment, Reference *Scenario, January 2050.*

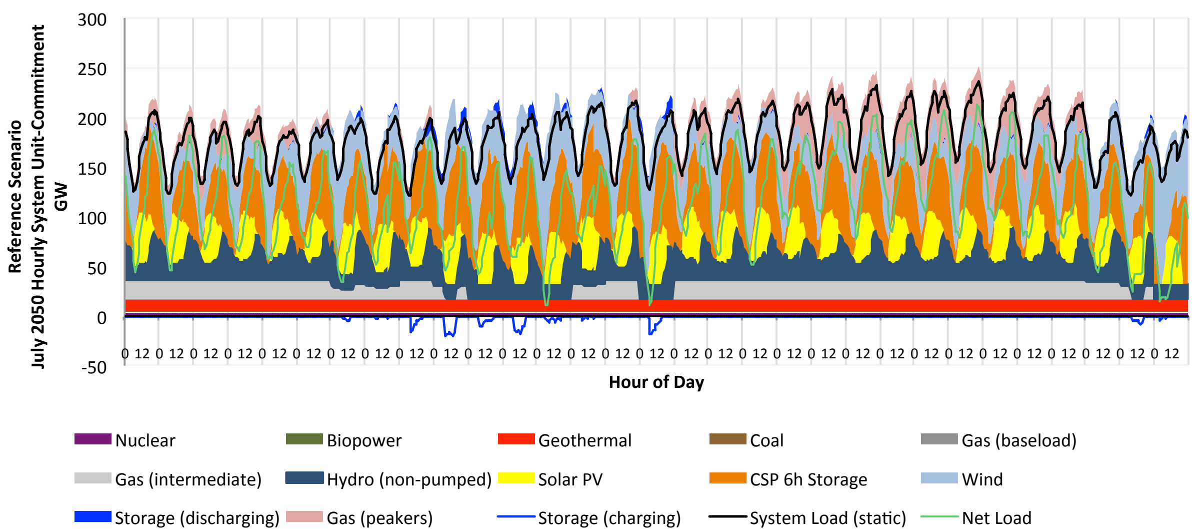


Figure 32. WECC System Hourly Unit-Commitment, Reference *Scenario, July 2050.*

5.2. SunShot and Low-Cost Batteries Scenario

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 hours of storage and 20 GW of CAES with an average of 12 hours of storage are installed. Both technologies are deployed predominantly in the Desert Southwest (Figure 28), in California, Arizona, and Nevada, to support large-scale solar PV installations. In this scenario, 270 GW of solar PV are installed while deployment of CSP with storage is less than 40 GW and wind installation levels are at 160 GW. In the Reference case, deployment levels for the three technologies are 70 GW, 120 GW, and 250 GW respectively.

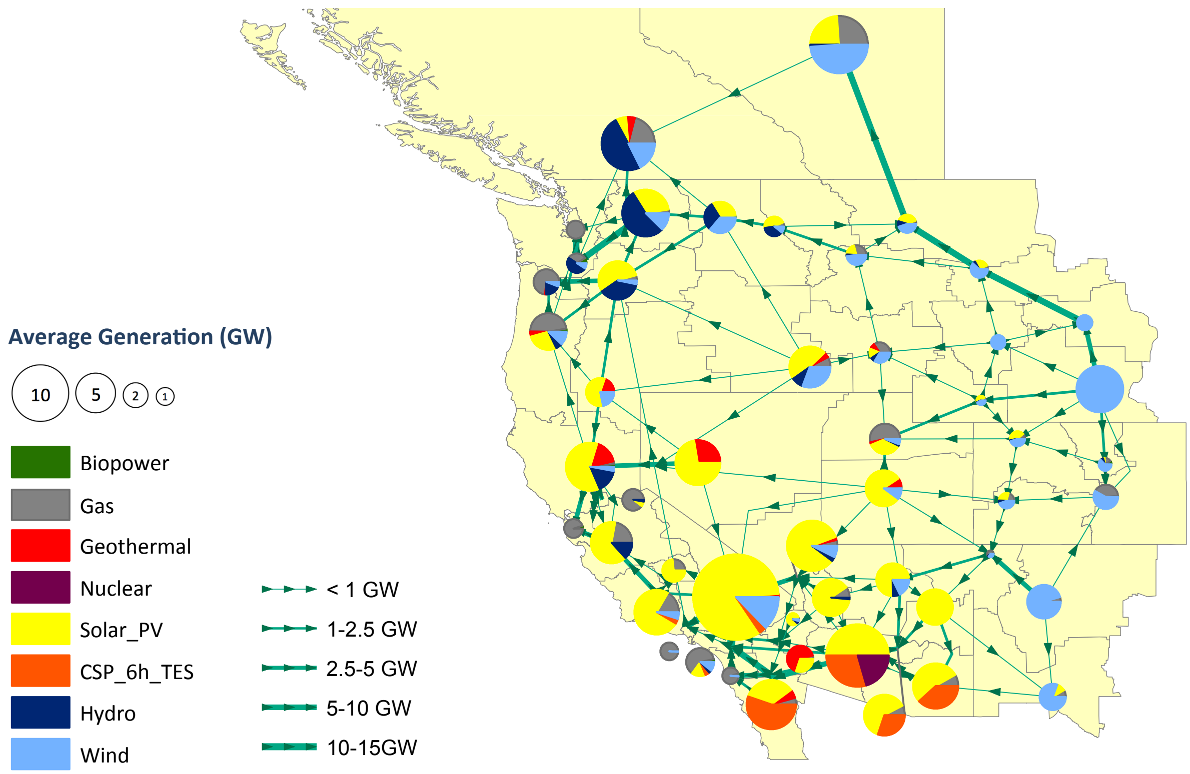


Figure 33. Map of average generation and transmission, SunShot and Low-Cost Batteries Scenario*, 2050.*

Relative to the *Reference* case, the unit-commitment schedule of the *SunShot and Low-Cost Batteries* system is much more similar across seasons and storage is used extensively throughout the year (Figure 34). The typical pattern for storage use is charging in the daytime – when PV is producing electricity, net load is usually 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. In January, storage charges during the day and helps to meet nighttime load together with wind (Figure 35). In April (Figure 36) and November (Figure 38), the pattern is very similar. Even during the time of highest system stress when load is at its peak levels in

July, excess energy is available when PV is producing at full output, net load is negative, and the deployed storage can be used to shift that energy to other times of the day where it is aided by hydro and gas peaker generation in meeting load (Figure 37).

The cyclical nature of solar PV, which is inexpensive in the *SunShot and Low-Cost Batteries* scenario, allows SWITCH-WECC to design a system that also exhibits diurnal periodicity. The model overbuilds solar PV capacity above daytime load and deploys low-cost storage capacity to provide daily arbitrage, shifting the excess solar PV energy to other times of the day when an energy deficit exists. Unlike in the *Reference* scenario, in which the system must address seasonal variations in energy availability from wind and build large amounts of additional generation to ensure that load is met when wind output is low, the *SunShot and Low-Cost Batteries* system relies on solar PV output levels that are similar across seasons. With the storage technologies modeled here, PV generation can be readily balanced on the daily timescale.

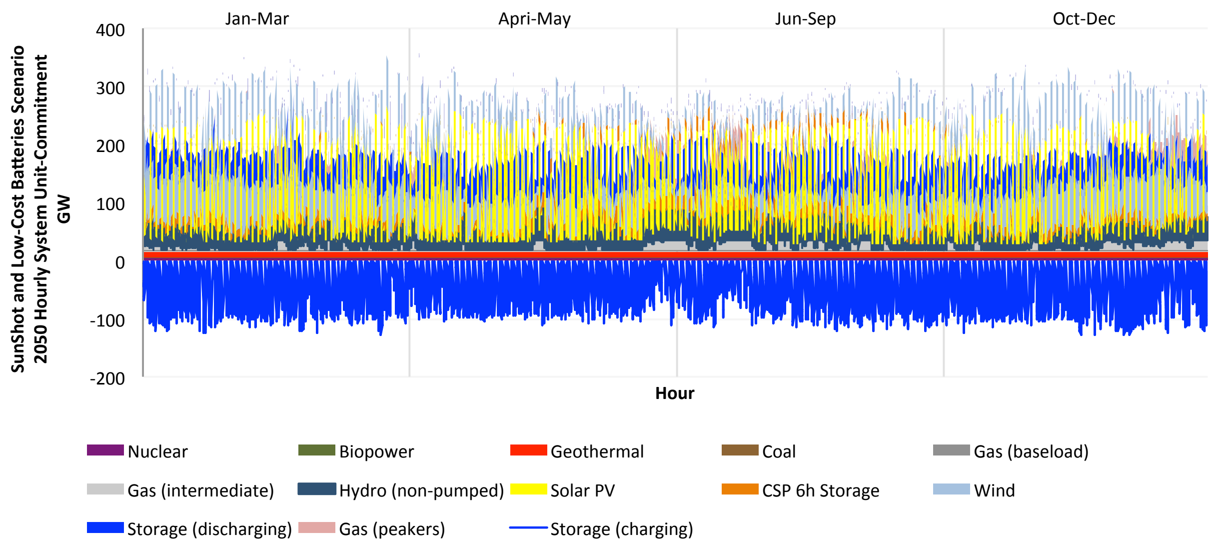


Figure 34. WECC System Hourly Unit-Commitment, SunShot and Low-Cost Batteries Scenario, 2050.

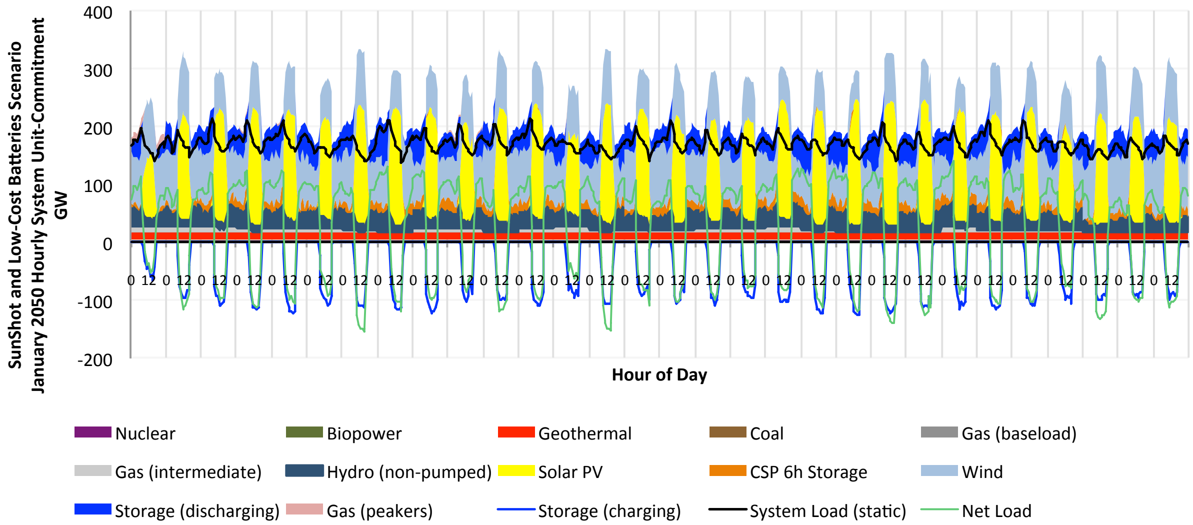


Figure 35. WECC System Hourly Unit-Commitment, SunShot and Low-Cost Batteries Scenario, January 2050.

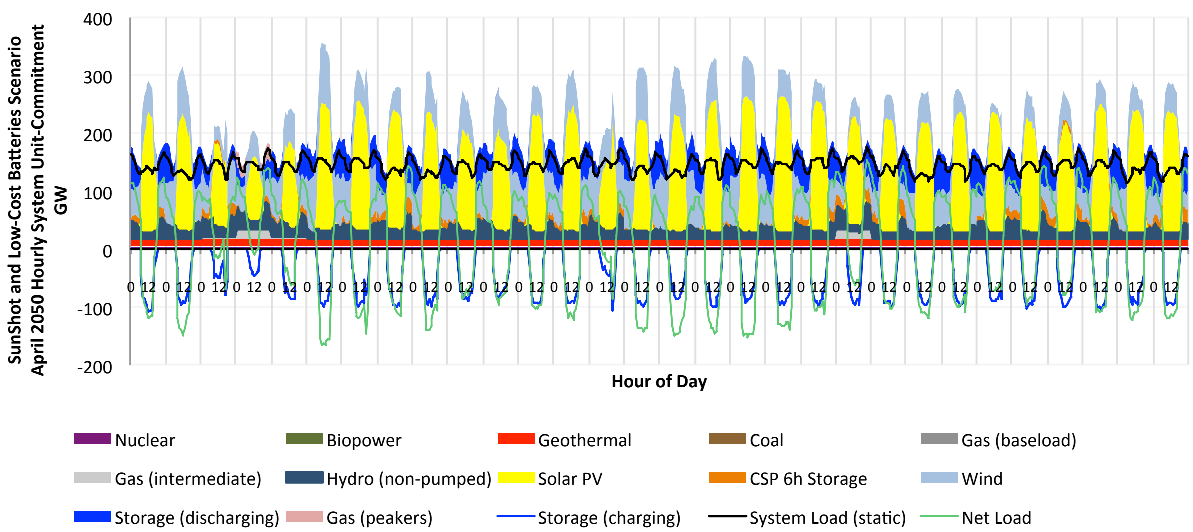


Figure 36. WECC System Hourly Unit-Commitment, SunShot and Low-Cost Batteries Scenario, April 2050.

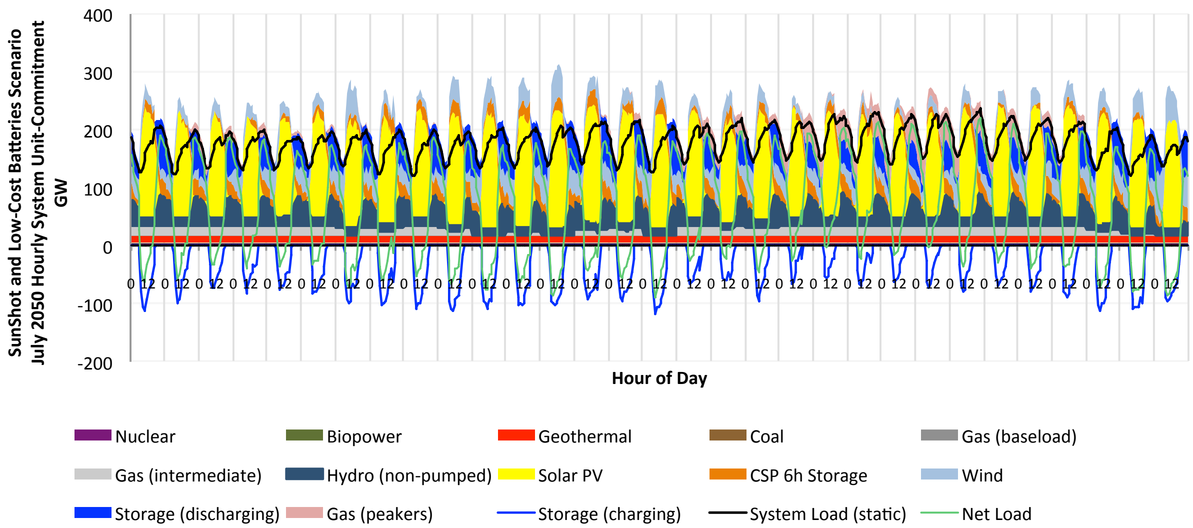


Figure 37. WECC System Hourly Unit-Commitment, SunShot and Low-Cost Batteries Scenario, July 2050.

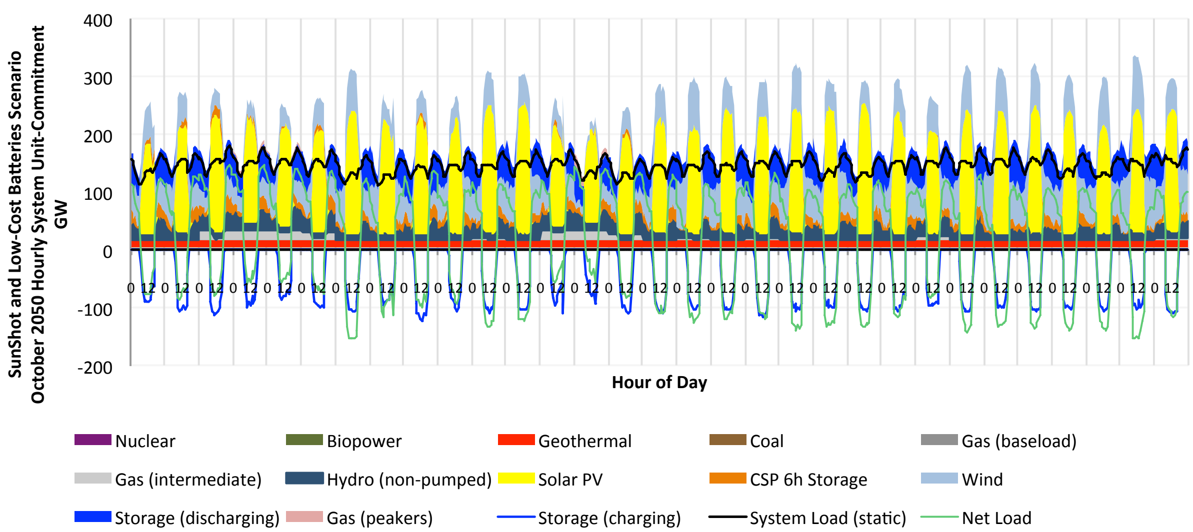


Figure 38. WECC System Hourly Unit-Commitment, SunShot and Low-Cost Batteries Scenario, October 2050.

5.3. No CSP-TES and 100 GW Solar PV Limit (High-Wind) Scenario

In the scenarios described above, inexpensive batteries incentivize solar PV deployment, displacing wind and CSP-TES capacity. In the *Reference* scenario, 250 GW of wind, 120 GW of CSP-TES, and 70 GW of PV capacity are installed; in the *Low-Cost Batteries* scenario, deployment levels are 230 GW, 60 GW, and 170 GW respectively. To further explore the storage needs of wind in particular, I removed the option to install CSP with 6 hours of storage and implemented a 100 GW limit on total solar PV deployment in the *No CSP and 100 GW Solar PV Limit* scenario. I initially attempted to disallow all solar technologies, but the optimization problem could not be solved by CPLEX within the runtime limits of the PSI cluster. The minimum level of PV deployment that yielded a solution was 75 GW. The case with 100 GW limit is shown here.

In the *No CSP and 100 GW Solar* scenario, a very large amount of wind capacity is installed across the WECC, reaching more than 450 GW by 2050. In addition, 20 GW of CAES with 7 hours of average maximum-load duration and 50 GW of batteries with 6 hours of maximum-load duration are deployed. Even at this very high deployment level of wind, energy availability is low in the summer months, requiring the commitment of gas generation – both CCGTs and peakers – to meet high summer load (Figure 39). Storage is used during that time, but it in the morning when load hasn't is at its lower levels for the day and when solar PV is generating at full output. The output from the 450 GW of wind capacity during that period is insufficient to meet load throughout the day, even if its profile could be matched to load (Figure 40).

In the *No CSP and 100 GW Solar PV Limit* scenario, excess energy from wind is available, but it occurs in the winter months. About 13 percent of total electricity production is spilled in the 2050 timeframe in this scenario. In contrast, only 3 percent of electricity produced is curtailed in the *Reference* case and 2 percent in the *SunShot and Low-Cost Batteries* scenario. Long-duration storage is not modeled in SWITCH and could potentially benefit wind technologies by smoothing seasonal variations in wind output.

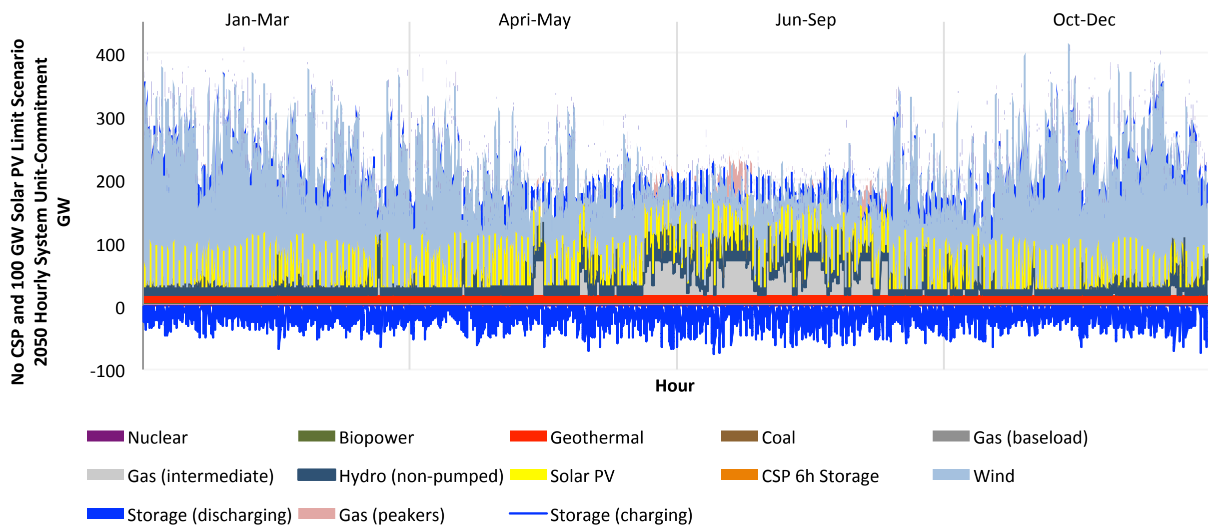


Figure 39. WECC System Hourly Unit Commitment, No CSP and 100 GW Solar PV Limit *scenario, 2050.*

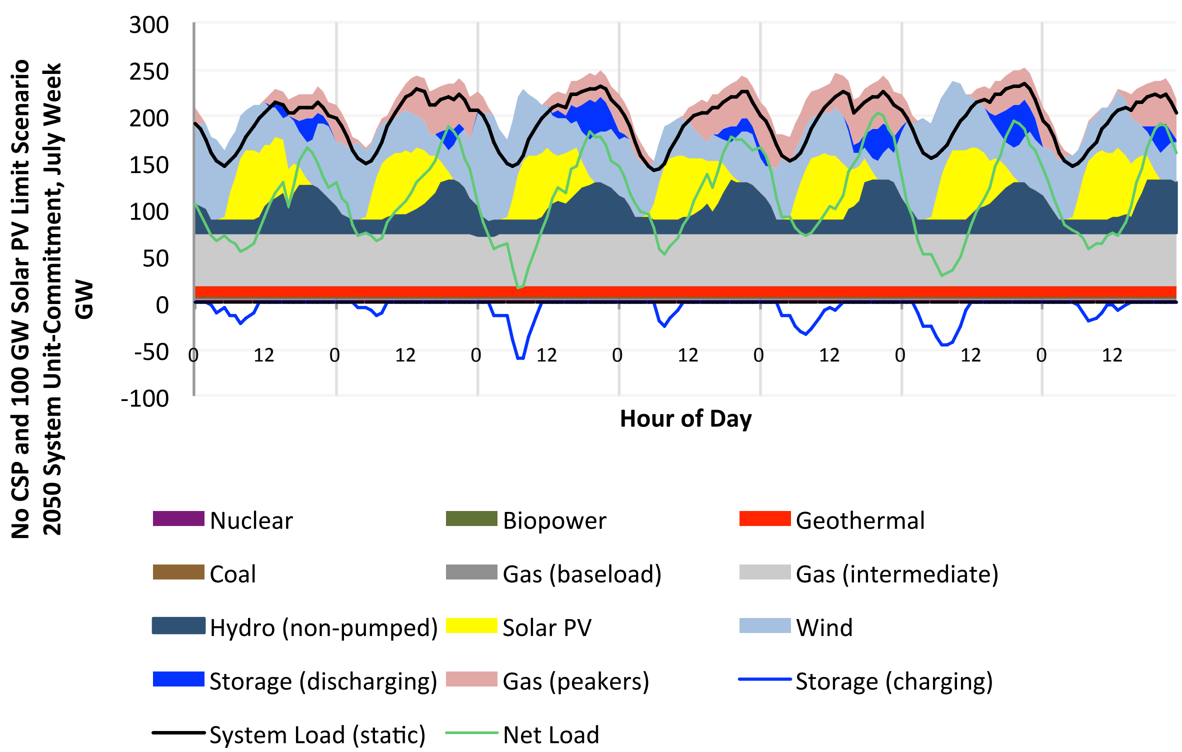


Figure 40. WECC System Hourly Unit-Commitment, No CSP and 100 GW Solar Limit *scenario, 2050, Week in July.*

VI. The Decarbonized Grid and Cost-Containment

1. The Flexibility Requirements of Wind and Solar PV

In the results shown here, the wind energy resource exhibits large seasonal variation that requires the use of natural gas or other fuels during low-wind seasons – or of the ability to store large amounts of wind energy with low losses and shift it to other times of the year via storage with a large energy subsystem component. 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.

Hourly wind output data for these wind sites are from the 3TIER wind power output dataset developed for the Western Wind and Solar Integration Study (3TIER 2010). Data for two more years – 2004 and 2005 – is available from 3TIER.

Figure 41 shows the hourly output profile of the wind projects deployed in the *No CSP and 100 GW Solar PV Limit* scenario based on wind potential data from 2004, 2005, and 2006. As evident in 2006, the wind resource data from 2004 and 2005 appears to exhibit seasonal variation. 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. A box plot of the hourly wind data by year and month is shown in Figure 42. While there are variations across 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. The output of the projects deployed in the *No CSP and 100 GW PV Limit* scenario would be lower than 112 GW for 75 percent of hours in July 2004, lower than 120 GW for 75 percent of hours in August 2005, and lower than 101 GW for 75 percent of hours in July 2006 (Figure 42). In the winter, the output of these projects would be higher than 183 GW for 75 percent of hours in December 2004, higher than 196 GW for 75 percent of hours in December 2005, and higher than 213 GW for 75 percent of hours in January 2006 (Figure 42).

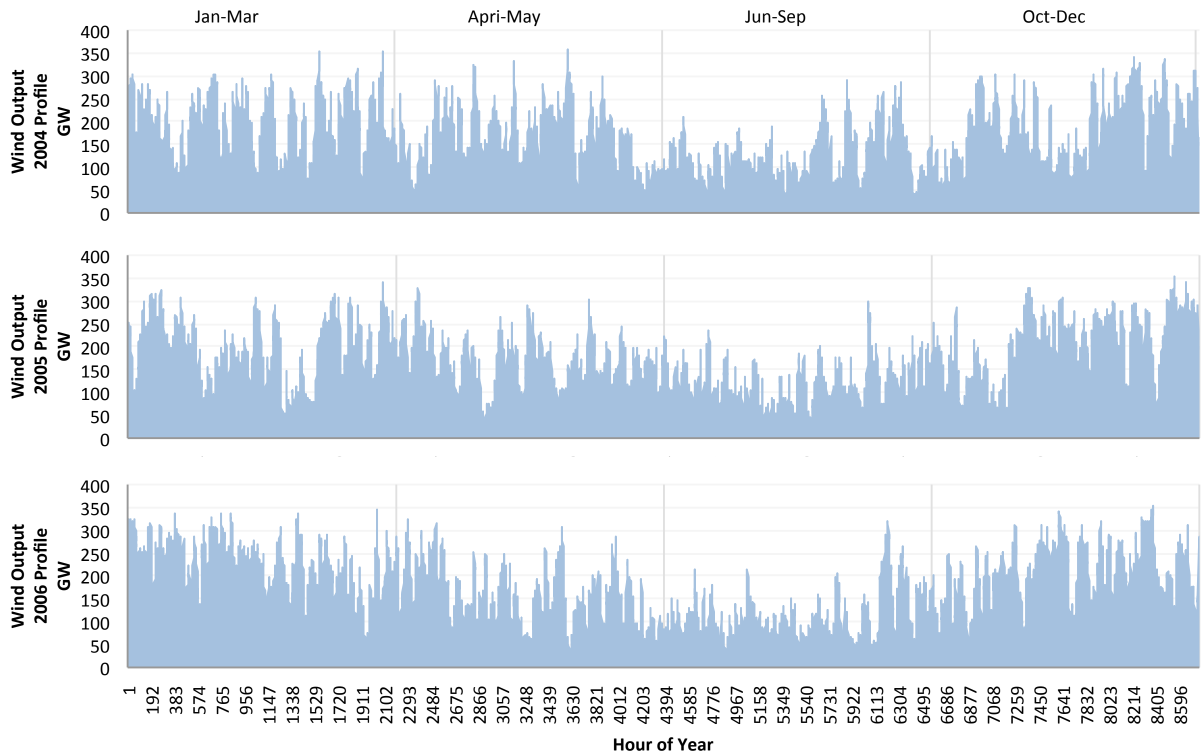


Figure 41. Hourly output of 450 GW capacity of wind projects deployed in the No CSP and 100 GW PV Limit Scenario based on 2004, 2005, and 2006 wind hourly output profile data.

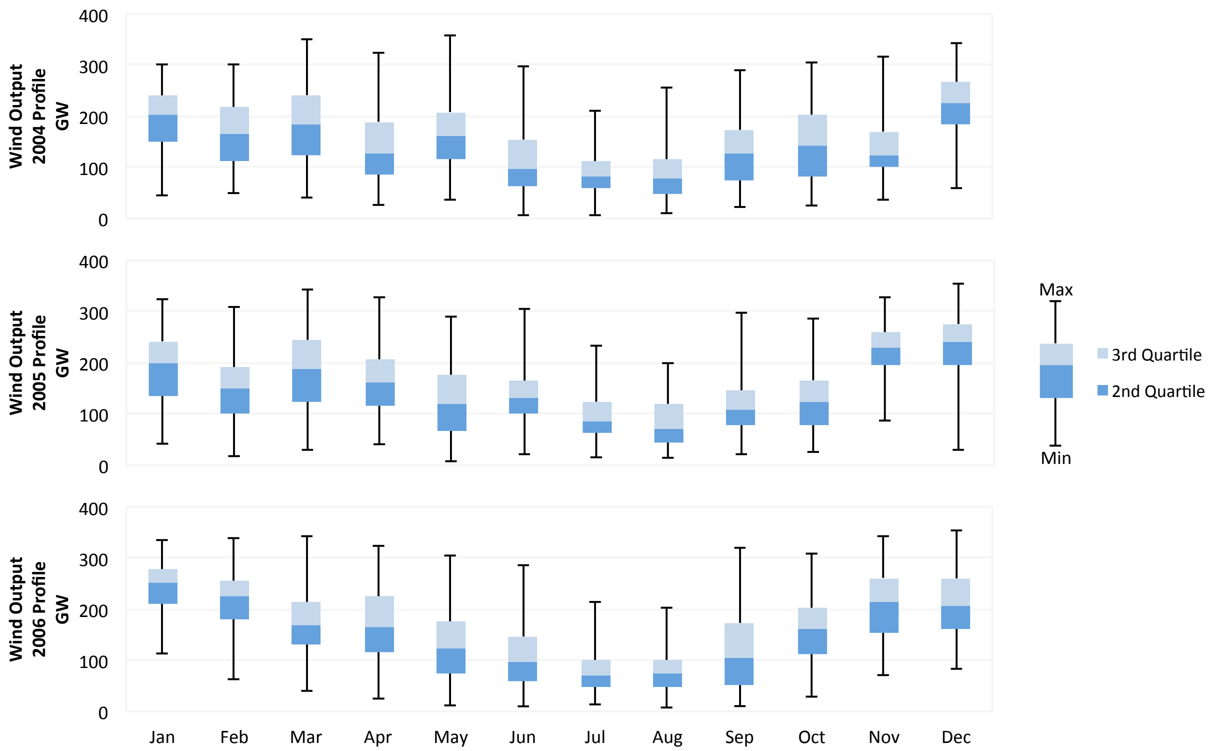


Figure 42. Box plot of hourly wind output quartiles by month for 2004, 2005, and 2006 based on the 450 GW of wind projects deployed in the No CSP and 100 GW PV Limit *scenario.*

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, which may be problematic from a cost and emissions perspective, or 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 grid stress in the summer.

Based on the 2006 3TIER data used, the highest total monthly output of the wind projects deployed in the *No CSP and 100 GW Solar PV Limit* scenario occurs in January, with 180 TWh of total electricity production, and the lowest occurs in August, with 57 TWh of total output. The total output of these projects based on 2004 and 2005 potential data also varies across months. With 2004 wind conditions, the 450 GW of wind projects in the *No CSP and 100 GW Solar PV Limit* scenario would produce 164 TWh in December and 64 TWh in July, the highest and lowest total monthly output for the year. Based on 2005 conditions, the highest total monthly output would be in December when 167 TWh of electricity would be produced and the lowest would be in August when the wind resource would be sufficient for 61 TWh of total output. The ratio of maximum to minimum total monthly output is 2.6 in 2004, 2.7 in 2005, and 3.1 in 2006.

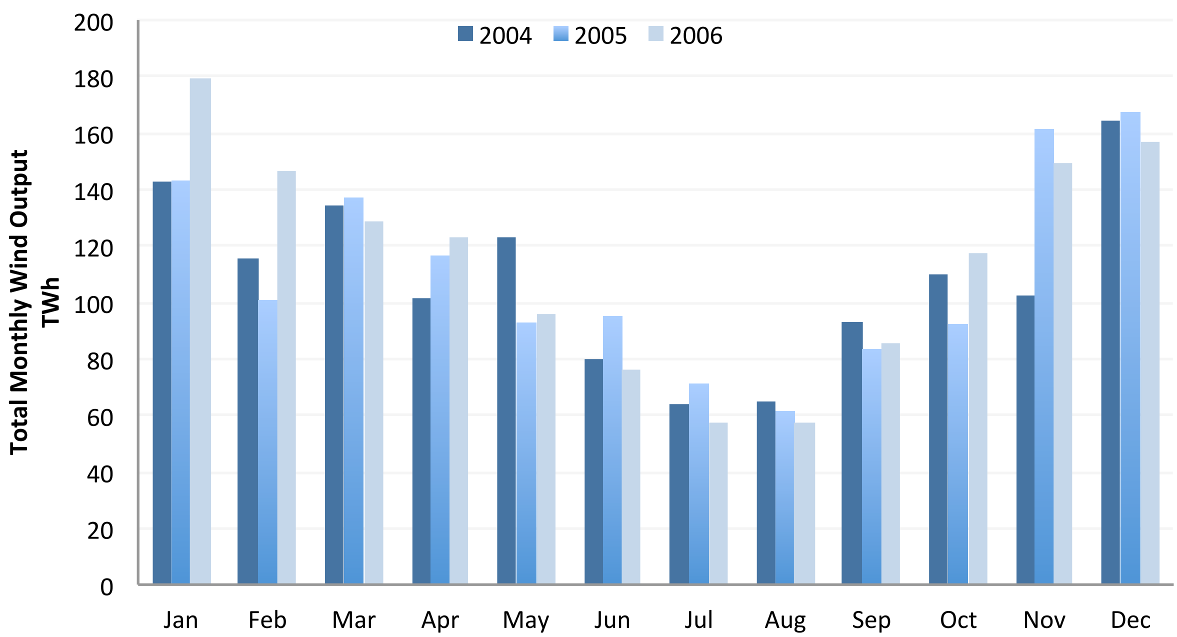


Figure 43. Total monthly output of 450 GW of wind projects deployed in the No CSP and 100 GW PV Limit *scenario based on 2004, 2005, and 2006 wind output data.*

A back-of-the-envelope calculation shows that leveling the 2006 wind profile by storing wind energy in December and January and discharging it in July and August would require shifting (157 + 180 – 58 – 57) / 2 = 111 TWh of electricity. (Peak net load in 2050 in the *No CSP and 100 GW Solar PV Limit* scenario is 202 GW, providing a rough estimate for the storage power capacity requirements.) Even at the optimistic goal for battery cost of $50/kWh, this translates into a needed investment of $5,550 billion if batteries were to be used for the purpose. Other storage options with lower costs for energy subsystem capacity would be needed to be able to fully utilize the wind resource available in the WECC.

Solar PV exhibits less pronounced seasonality than wind and total energy availability from it stays more similar across seasons. Based on 2006 solar PV resource data – the only year of hourly data available for this study – the month with the most total energy available from the 270 GW of solar PV projects installed in the *SunShot and Low-Cost Batteries* scenario is May with 67 TWh of electricity production and the month with the least total energy available is December with 43 TWh of electricity production. The ratio of maximum to minimum total PV monthly output is 1.6 whereas the average ration for the three years of available wind data is 2.8 in the *No CSP and 100 GW Solar PV Limit* scenario as described above.

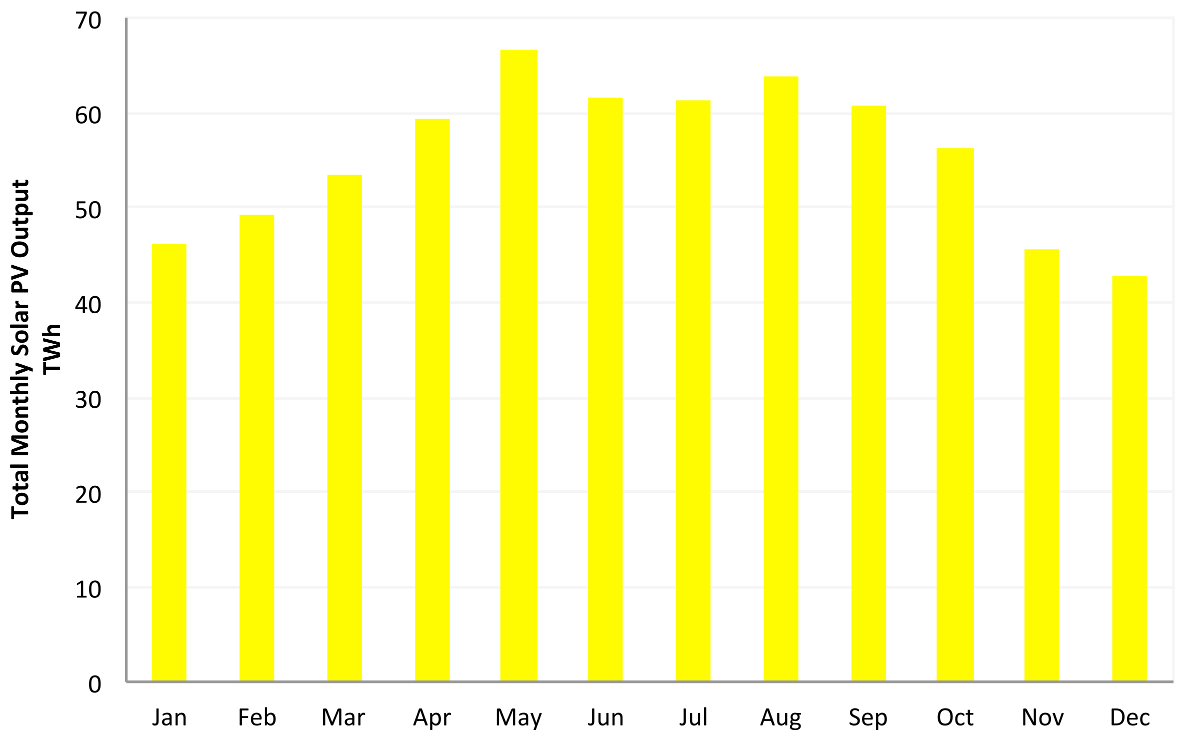


Figure 44. Total monthly output of 270 GW of solar PV projects deployed in the SunShot and Low-Cost Batteries *scenario based on 2006 solar PV output data.*

Solar PV output follows a known, cyclical diurnal pattern – the sun's. The solar PV resource in the WECC, like load, exhibits an inherent periodicity at the daily timescale. This periodicity is similar across seasons: the time when the sun is not shining between sunset and sunrise is 10 to 14 hours depending on time of year in the Desert Southwest where the best solar PV resource is available. During that time, storage can be used to compensate for the lack of PV output. As a result, storage with duration of several hours providing daily arbitrage is very well suited to balance the daily variability in solar PV.

Because both load and PV output 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.

2. The Role of System Flexibility Resources

2.1. CAES and Batteries

As discussed above the availability of low-cost solar power is a main driver of storage deployment as storage devices providing daily arbitrage are well suited to balance the daily cycle in solar output. With SunShot solar costs, CSP-TES dominates, but if low-cost batteries are available, it is largely displaces by a combination of solar PV and batteries, serving a similar function in the 2050 low-carbon grid. The tradeoffs and synergies among these technologies are discussed further in *Section 2.2* below.

Before 2050, compressed air energy storage outcompetes battery storage, even if the cost of batteries is reduced to the ARPA-E target as in the *Low-Cost Batteries* scenario or the efficiency of batteries is increased as in the *High-Efficiency Batteries* scenario. While the power subsystem capacity cost is lower for batteries under the assumptions of the *Low-Cost Batteries* scenario, the energy subsystem cost remains higher than that of CAES. In 2040 in the *Low-Cost Batteries* scenario, 9 GW of CAES with 7-hour duration and 3 GW of batteries with 6-hour duration are installed. By 2050, a very large deployment of battery capacity takes place to accommodate a large buildout of renewables and a limit on the amount of natural gas that can be used due to an ever more stringent carbon cap. The battery deployment level reaches 68 GW (with 6-hour duration on average) while CAES capacity increases only slightly to 10 GW (with 11-hour duration). The difference in additional deployment of the two technologies between 2040 and 2050 suggests that the emissions from CAES are a limiting factor in how much of it can be used by the very-low-carbon 2050 power system. The batteries are used throughout the year to shift daytime solar PV energy to the nighttime. In this scenario, emissions from 10 GW of CAES in 2050 are 5 percent of the total system emissions (Figure 50). A large amount of CAES capacity cannot be used in a similar manner because it would entail emissions levels inconsistent with a stringent 2050 cap on greenhouse gases under the present assumptions about its characteristics.

Among the highest deployment of CAES capacity occurs in the *Nuclear and CCS* scenario, in which 22 GW of CAES are installed. The total deployment of CAES and batteries in this scenario is similar to that in the *Reference* scenario, although much less intermittent renewable capacity is deployed. CAES in the *Nuclear and CCS* scenario is used to its full capacity only part of the year. In this scenario, CAES is responsible for 8 percent of 2050 carbon emissions.

2.2. CSP with Thermal Energy Storage

While deployment of CSP with TES does not take place until 2040 in any of the scenarios explored here, this technology plays a crucial role in the long term as it can provide low-carbon flexibility to the power system at a range of timescales. As modeled here, solar thermal energy is more expensive on a levelized cost basis than either wind or solar PV; however, it is the timing of the energy – not the cost – that becomes the most important factor as the grid reaches very low greenhouse gas emission levels. In the *Reference* scenario, 116 GW of CSP with 6 hours of TES are installed, which help to balance both the seasonal intermittency of wind energy and the daily periodicity of solar PV (Figure 45). With SunShot costs in the *SunShot* scenario, CSP with storage is still the dominant solar technology: the capacity of both PV and CSP with 6h of TES increases by close to 40 percent relative to the *Reference* scenario, reaching 94 and 160 GW respectively and displacing wind.

The solar thermal resource is largest in the summer when the wind resource is limited, but is much diminished in the winter months when wind output is high (Figure 46). In the *Reference* scenario, for example, total electricity production from the 116 GW of deployed CSP with 6 hours of thermal storage is 38 TWh in August 2050, but only 14 TWh in December 2050. CSP is thus a good complement for wind power as it does not produce much excess energy when the wind resource is at its peak in the winter months, resulting in less curtailment and wasted electricity production, but it can help make up for the scarcity of wind energy in the summer and thus help avoid the need for additional generation capacity to be built to meet summer load.

CSP with storage is also very well suited to balance the daily cycle of PV electricity production. It stores thermal energy during the day while the sun is shining and then releases it after sunset into the evening and nighttime when energy from PV is unavailable and load is usually at its daily high (Figure 47). This pattern is in place throughout the year. Only CSP with 6 hours of storage is modeled here; were the technology to be allowed to install thermal storage of even longer duration, it is likely that it would have additional value for the system, making it possible to dispatch energy throughout the night.

Providing additional evidence for the high value of flexibility in the decarbonized 2050 power system is that the availability of other low-cost and low-carbon sources of flexibility such as inexpensive battery technology or demand response reduces the deployment of CSP with 6h of thermal storage and instead incentivizes installation of solar PV projects. In the *Low-Cost Batteries*, *Load-Shifting*, and *Load-Shifting and Flexible EV Charging* scenarios, solar PV deployment reaches 168 GW, 126 GW, and 207 GW respectively by 2050, a large increase from the 70 GW installed in the *Reference* scenario. In contrast, installation of CSP with 6 hours of thermal storage decreases from 120 GW in the *Reference* case to 61 GW, 89 GW, and 37 GW in the *Low-Cost Batteries*, *Load-Shifting*, and *Load-Shifting and Flexible EV Charging* scenarios respectively. In these cases, nighttime load served by CSP with TES in the *Reference* scenario can be met with PV energy stored in batteries during the day or by shifting it to the daytime when solar PV is available.

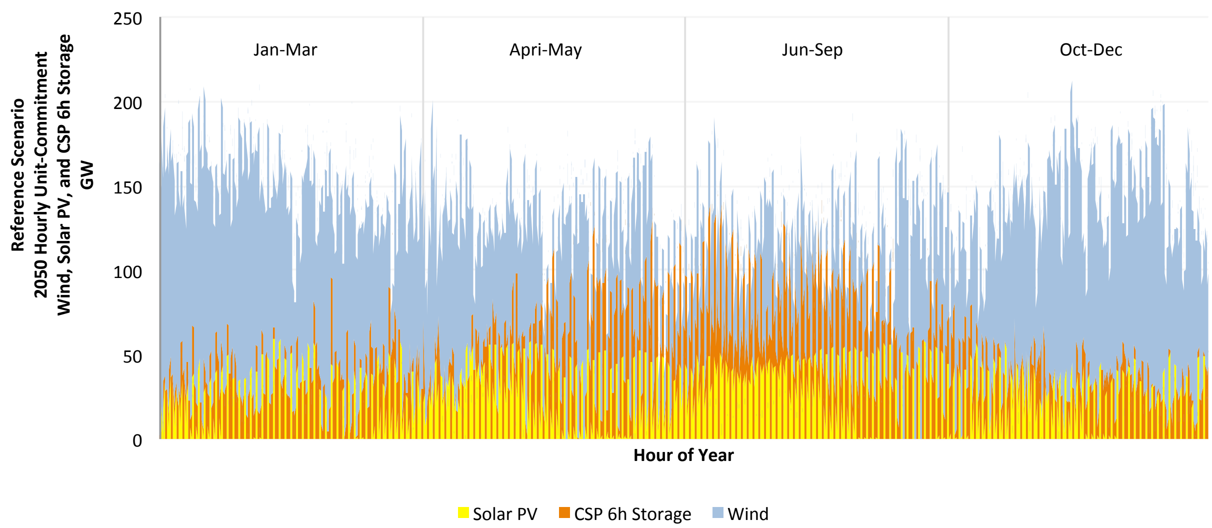


Figure 45. Hourly unit-commitment of wind, solar PV, and CSP with 6 hours of TES, Reference scenario, 2050.

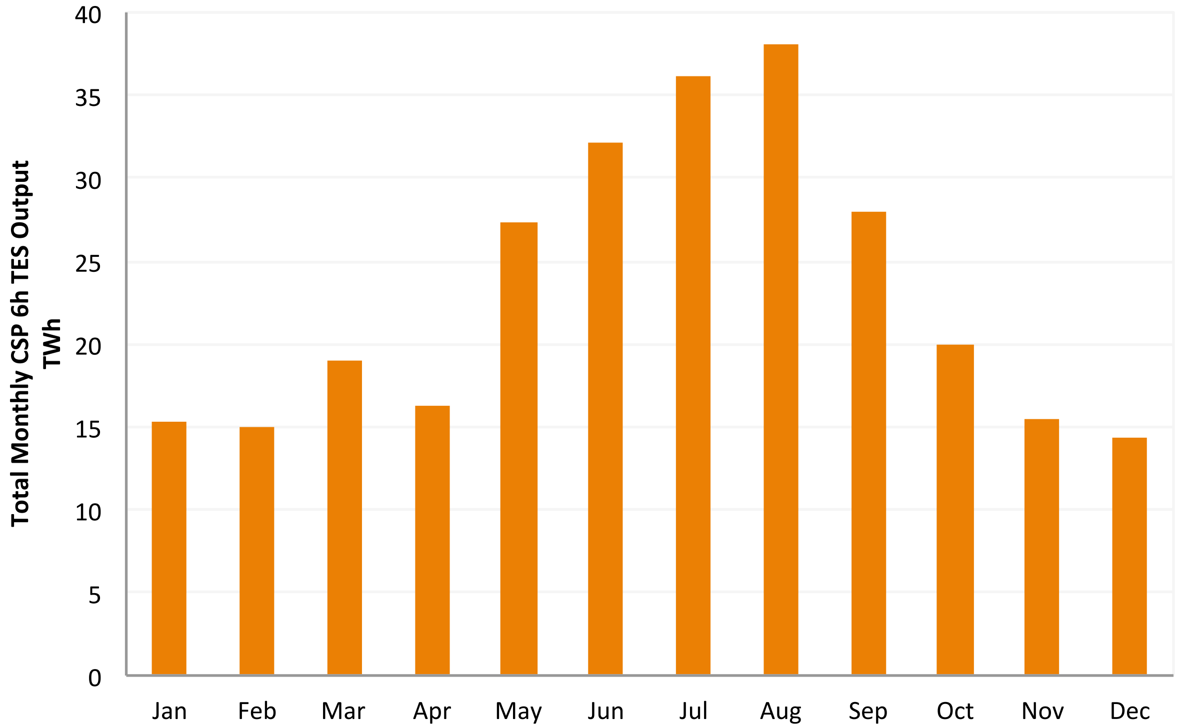


Figure 46. Total monthly output of the 120 GW of CSP with 6h of thermal energy storage installed in the Reference *scenario in 2050.*

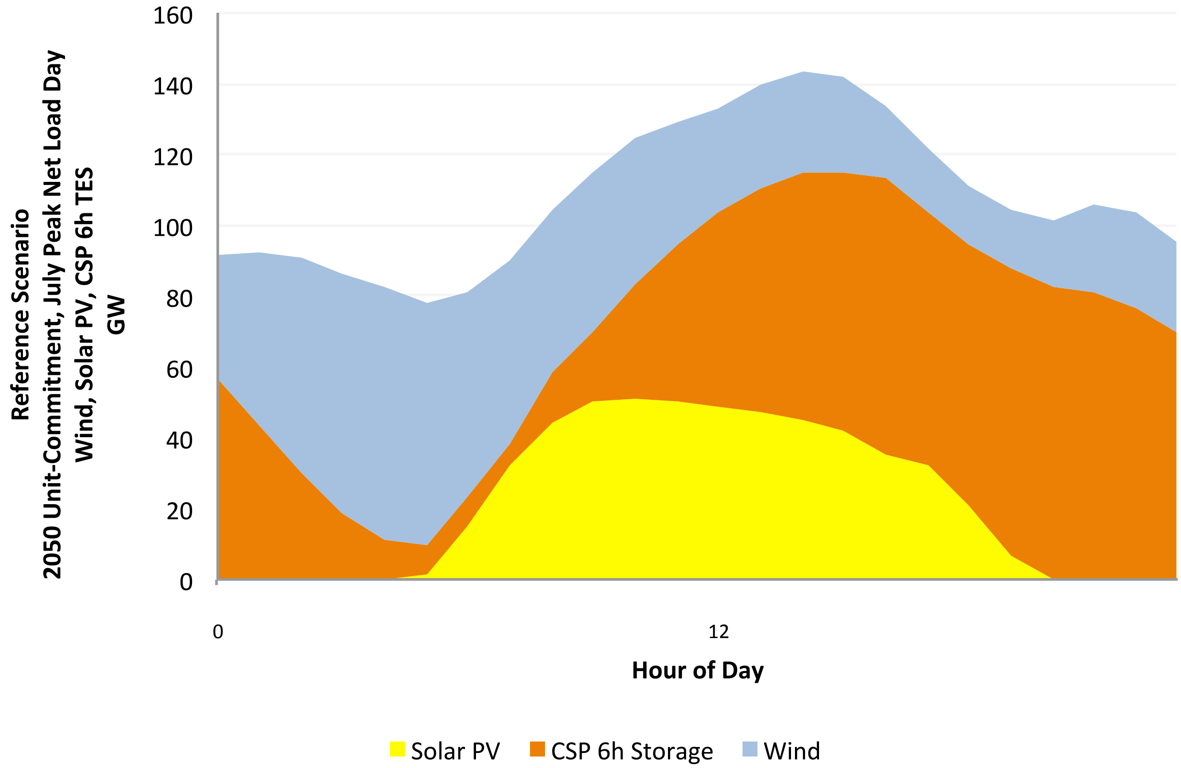


Figure 47. Hourly unit-commitment of wind, solar PV, and CSP with 6 hours of TES on the peak net load day, Reference scenario, July 2050.

2.3. Demand Response

Like the availability of low-cost batteries, flexibility from load-shifting – both from demand response from thermal loads and from flexible EV charging – incentivizes deployment of solar PV. In the *Load-Shifting and Flexible EV Charging* scenario, 207 GW of solar PV are installed in the WECC in 2050. The pattern of load shifting is opposite from that in the present day when load is usually moved from the daytime peak to the nighttime when demand tends to be lower. Rather, it is nighttime, morning, and evening loads that are shifted to the middle of the day when an abundant source of carbon-free energy – solar PV – is available (Figure 48 and Figure 49). This finding has implications for which loads can be most valuable as a source of flexibility to the decarbonized power system. At present, afternoon use of air-conditioning is a main target for demand response programs. However, it is loads consuming energy at other times of the day that are shifted in the 2050 (and as early as 2020), providing the most value to the system.

The sources of demand response modeled here 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. Because of its diurnal availability pattern, the demand response resource can be matched well to the output of solar PV, which also exhibits daily periodicity. It therefore incentivizes deployment of PV at the expense of CSP with 6 hours of thermal storage. Relative to the *Reference* scenario, which has PV deployment of 69 GW and CSP 6h TES deployment of 117 GW in 2050, the total installation level of PV increases to 207 GW and decreases to 37 GW for CSP 6h TES in the 2050 *Load-Shifting and Flexible EV Charging* scenario.

The same pattern of load-shifting is in place in all seasons: evening and nighttime loads are shifted to the day when solar PV is available, allowing for a large capacity of PV to be fully utilized without curtailment. Seasonal variations in the total renewable energy availability are an important feature of the *Load-Shifting and Flexible EV Charging* scenario system. In January, net load exhibits very little variation, staying low and relatively flat throughout the month. Abundant wind energy is available in the winter to help meet the remaining non-shiftable nighttime load (Figure 48). Low wind capacity factors in July, however, still pose problems for the system, even as plenty of flexibility exists to shift loads within the day in the summer. In late July in the *Load-Shifting and Flexible EV Charging* scenario, nighttime load remains high and requires the use of intermediate and peaker gas generation, even after a large fraction of it is shifted to the middle of the day when solar PV is available (Figure 49). Shifting and thermal loads and flexible EV charging is not needed during the extended periods of time when the system has either abundant energy (e.g. in January) or experiences energy scarcity (e.g. in July). The availability of flexible loads that can only be shifted a few hours therefore does not incentivize wind deployment because of wind's large seasonal variations in output.

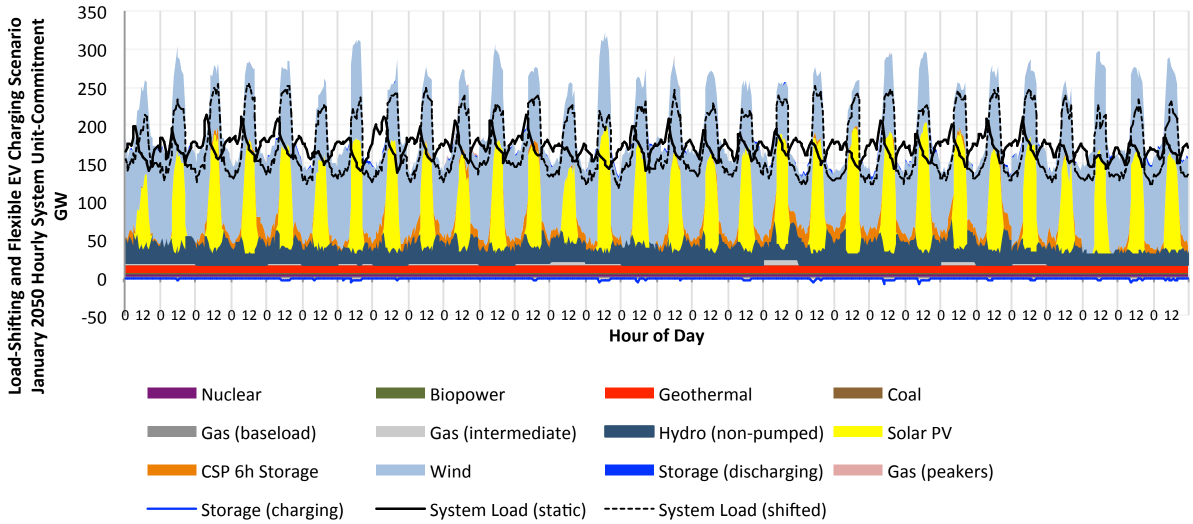


Figure 48. WECC hourly system unit-commitment, Load-Shifting and Flexible EV Charging *scenario, January 2050.*

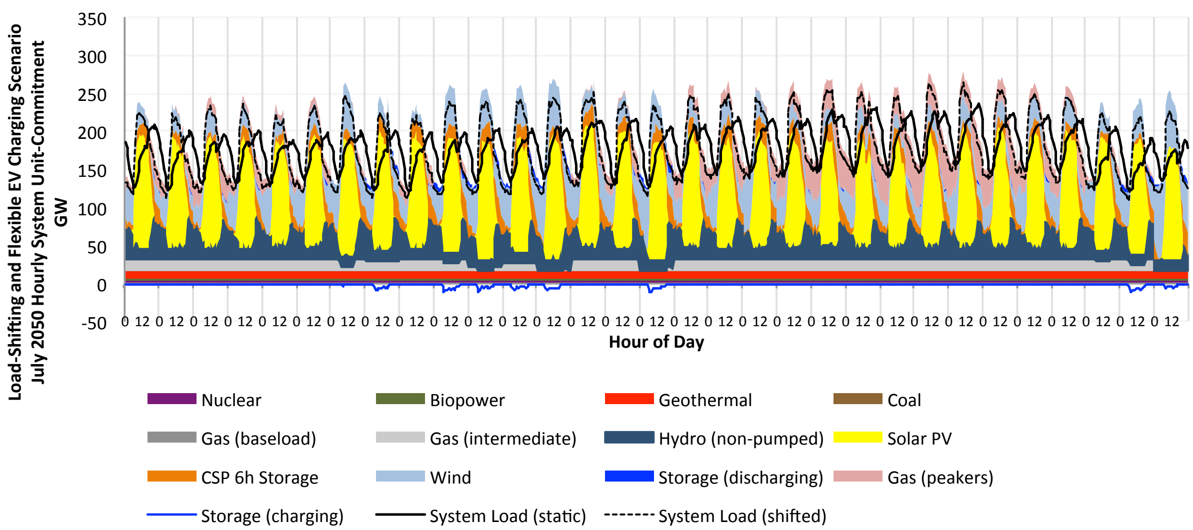


Figure 49. WECC system hourly unit-commitment, Load-Shifting and Flexible EV Charging *scenario, July 2050.*

2.4. Natural Gas

Natural gas generation is the main source of emissions across scenarios in 2050, with some variation in the relative contribution of different gas technologies. Natural gas fuel is of very high value to the system as it can provide energy in any season in addition to fast-ramping capabilities to follow load on the hourly timescale. However, the total amount of natural gas that can be used by the system is limited by the carbon cap.

The price of natural gas is not an important driver of system dynamics in 2050. In the *High-Price Natural Gas* scenario, doubling the price of natural gas relative to the Reference case effects negligible changes in the system energy and capacity mix (Figure 24 and Figure 25) as well as to the cost of power (Figure 58). Conversely, the emissions level of natural gas is a crucial factor for the cost of power in the 2050 timeframe. The *Methane Leakage* scenario has the highest average cost of power of all scenarios investigated. Under a strict carbon cap, the amount of natural gas that can be used in the *Methane Leakage* scenario is smaller relative to the *Reference* case, necessitating the deployment of 22 GW of additional wind power and 15 GW of additional CSP with 6 hours of thermal storage (PV deployment is reduced by 11 GW) to avoid the need for running peaker natural gas combustion turbines and incurring the associated emissions.

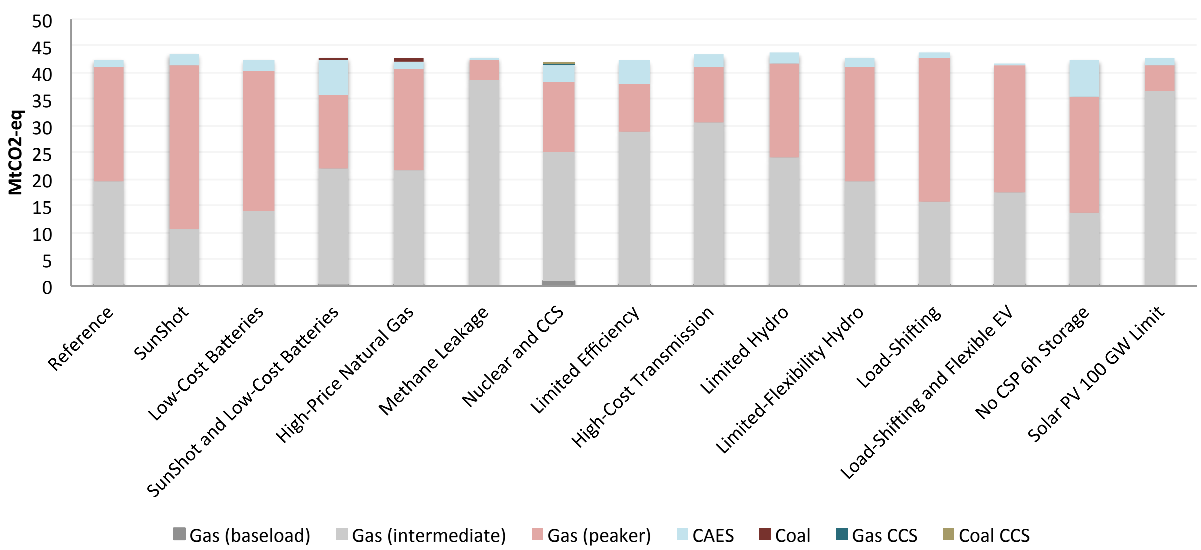


Figure 50. Carbon emissions in 2050 by source and scenario.

2.5. Hydropower

Hydropower is an important source of energy as well as system flexibility across the scenarios presented here, providing load-following and operating reserves. In the 2030 timeframe, hydropower is used to follow net load extensively. Limiting the flexibility of hydropower, whether through reducing hydro energy availability (*Limited Hydro* scenario) or its ability to vary output (*Limited-Flexibility Hydro* scenario) is a main driver of storage deployment in the scenarios presented here in the 2030 timeframe.

The *Limited Hydro* scenario reduces the overall energy available from hydro to 75 percent of historical levels by 2030 and 50 percent of historical levels by 2050 in recognition of possible changes in precipitation and snowpack levels due to climate change. This energy is compensated for by expansion in gas generation as well as wind, solar, geothermal, and biopower, displacing any remaining coal. Additional compressed air energy storage is also deployed and, unlike in the *Reference* scenario, the available storage is used throughout the year. A key driver of the storage requirements is that less hydro energy available to use during net peak load hours, so other sources of energy are needed to meet demand during those times, and, because of the cap on carbon, additional use of gas generation is limited.

For example, on a day in January, extra CCGT capacity is committed and used throughout the day in the *Limited Hydro* scenario (Figure 52) relative to the Reference scenario (Figure 51). The SWITCH investment optimization also builds larger capacities of wind and solar PV in the *Limited Hydro* scenario. Unlike the *Reference* system, which can meet the evening increase in net load by ramping up hydropower, the *Limited Hydro* system requires additional energy from other sources – CCGTs and wind – to meet load in the evening. It also complements these resources by releasing energy stored during the day when solar is also available and peak net load is low. Deploying and using storage in the Limited Hydro scenario is determined to be more cost-effective than starting up additional CCGT units or running expensive combustion turbines to meet the evening load.

The system behavior is similar in the *Limited-Flexibility Hydro* scenario. In this case, the minimum flow requirement for hydro plants is 75 percent of average flow rather than 50 percent of average flow as in the *Reference* scenario. The energy availability of hydropower during the peak net load hours is therefore also reduced because more energy must be released during other times. Baseloading a larger fraction of hydro energy results in a larger mismatch between the temporal availability of that energy and load, and storage is used to shift energy available during times of low net demand to the hours of peak net load.

These results show that assumptions about hydropower availability and flexibility are key drivers of storage deployment results. A number of constraints affect the extent to which hydropower can be used to balance the power system including environmental considerations, fishing, and recreational uses of the rivers where dams are located. Very limited data on hydropower operations are publicly available, making it difficult to accurately assess the realism of hydro operations in SWITCH relative to historical patterns. It is also unclear whether past operational patterns will persist into the future both because of new constraints or the availability of value of the system that hydro projects can provide and monetize. As discussed in Section 4 below, the availability of flexible hydropower is a key determinant of system costs.

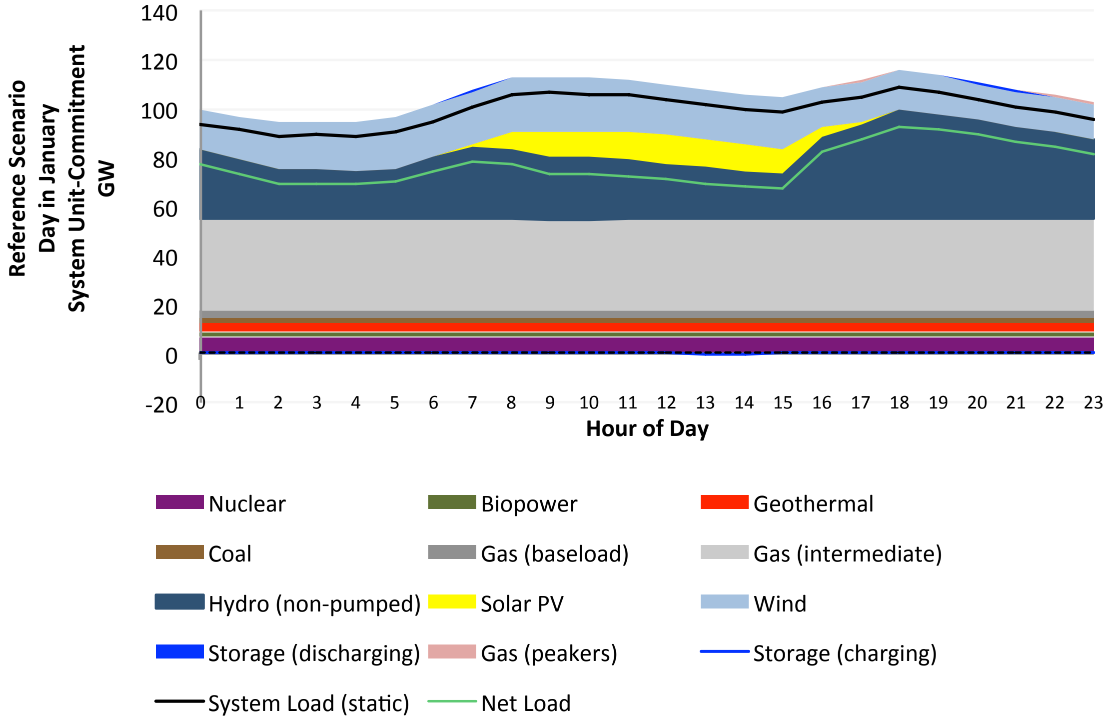


Figure 51. WECC system unit-commitment, Reference *scenario, January day, 2030.*

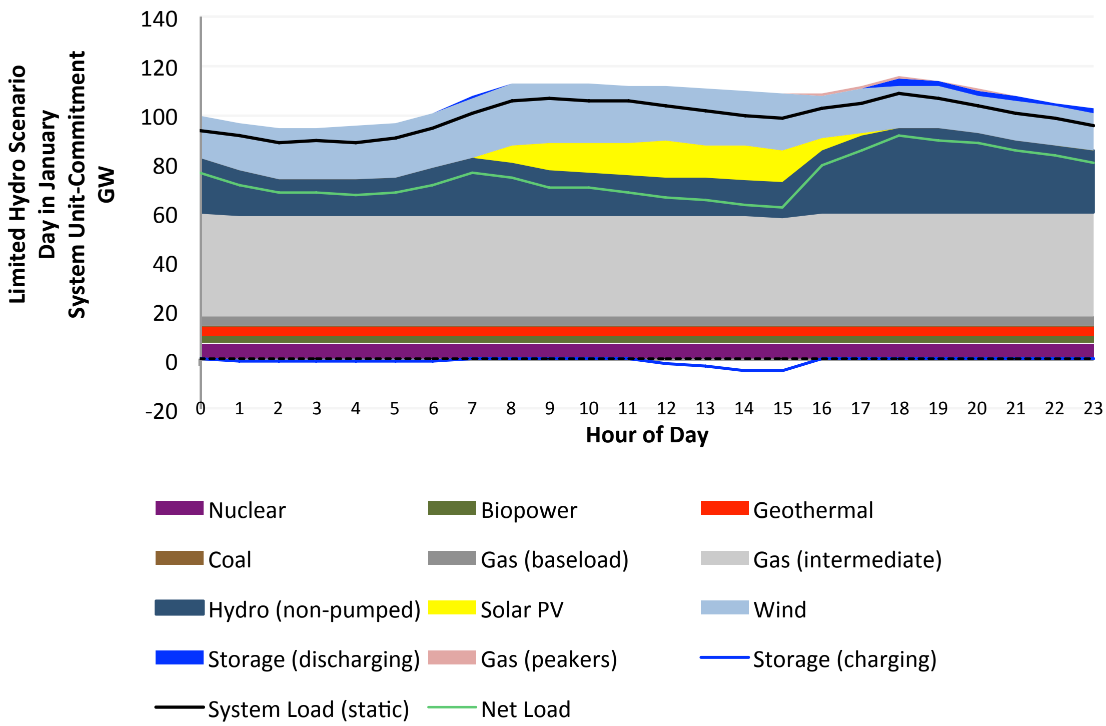


Figure 52. WECC system unit-commitment, Limited Hydro *scenario, January day, 2030.*

2.6. Transmission

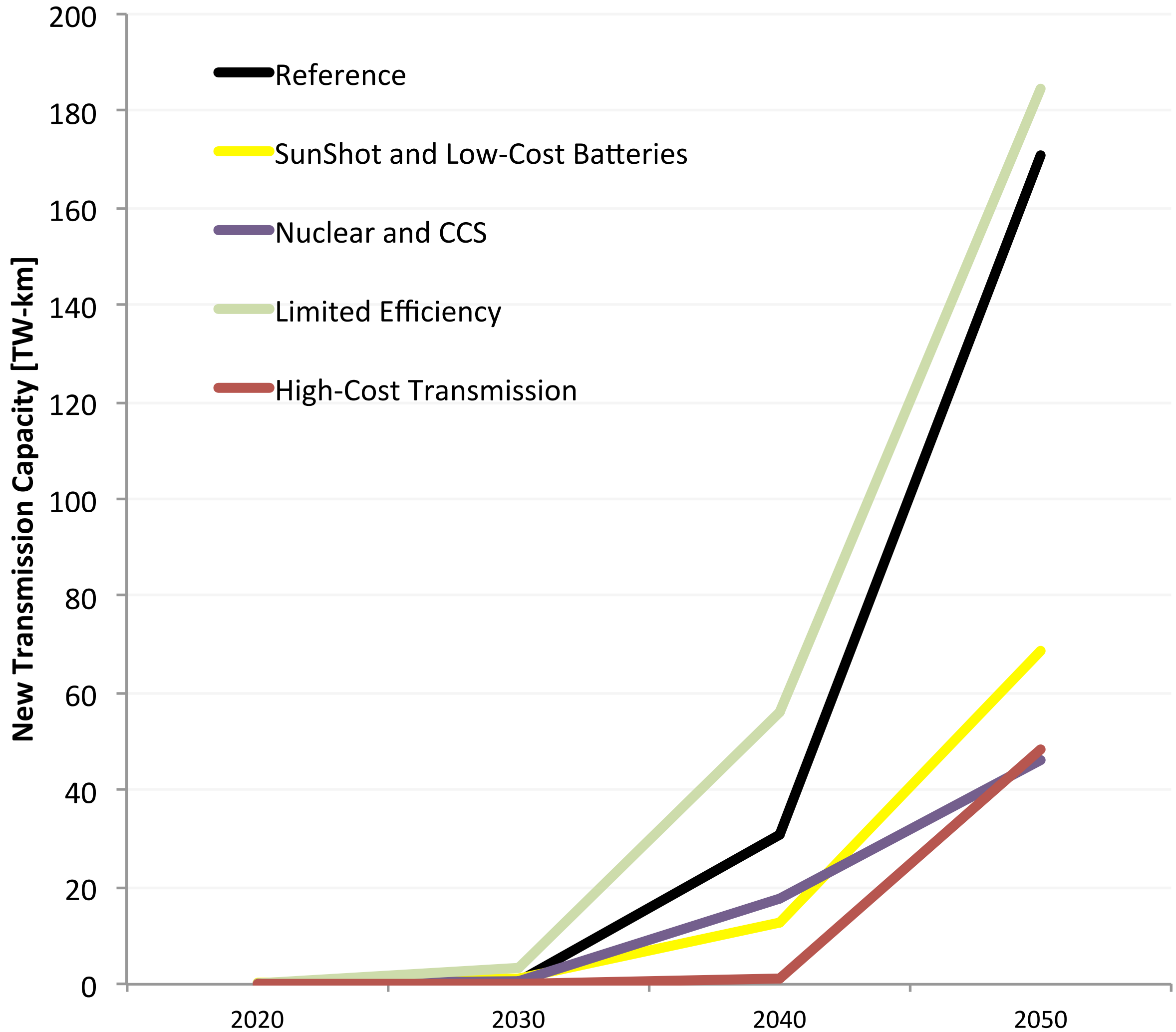


Figure 53. New transmission capacity by period.

Transmission is an important source of system flexibility as it allows for the matching of supply and demand in space. Deployment of wind power is the main driver of transmission deployment in the scenarios explored here as the best wind resource is located largely in the eastern part of the WECC, along the backbone of the Rockies, farm from the coastal load centers. Scenarios with higher wind deployment therefore tend to have higher transmission buildouts. In the *Reference* scenario, 170 TW-km of new transmission are deployed by 2050 (Figure 54). In contrast, the *Sunshot and Low-Cost Batteries* scenario, which has a lower wind deployment level and relies mostly on solar PV deployment in the Southwest, requires 70 TW-km of new transmission in 2050 to bring the resource to load (Figure 55). Tripling the cost of transmission in the *High-Cost Transmission* scenario reduces transmission as well as wind deployment relative to the *Reference* case.

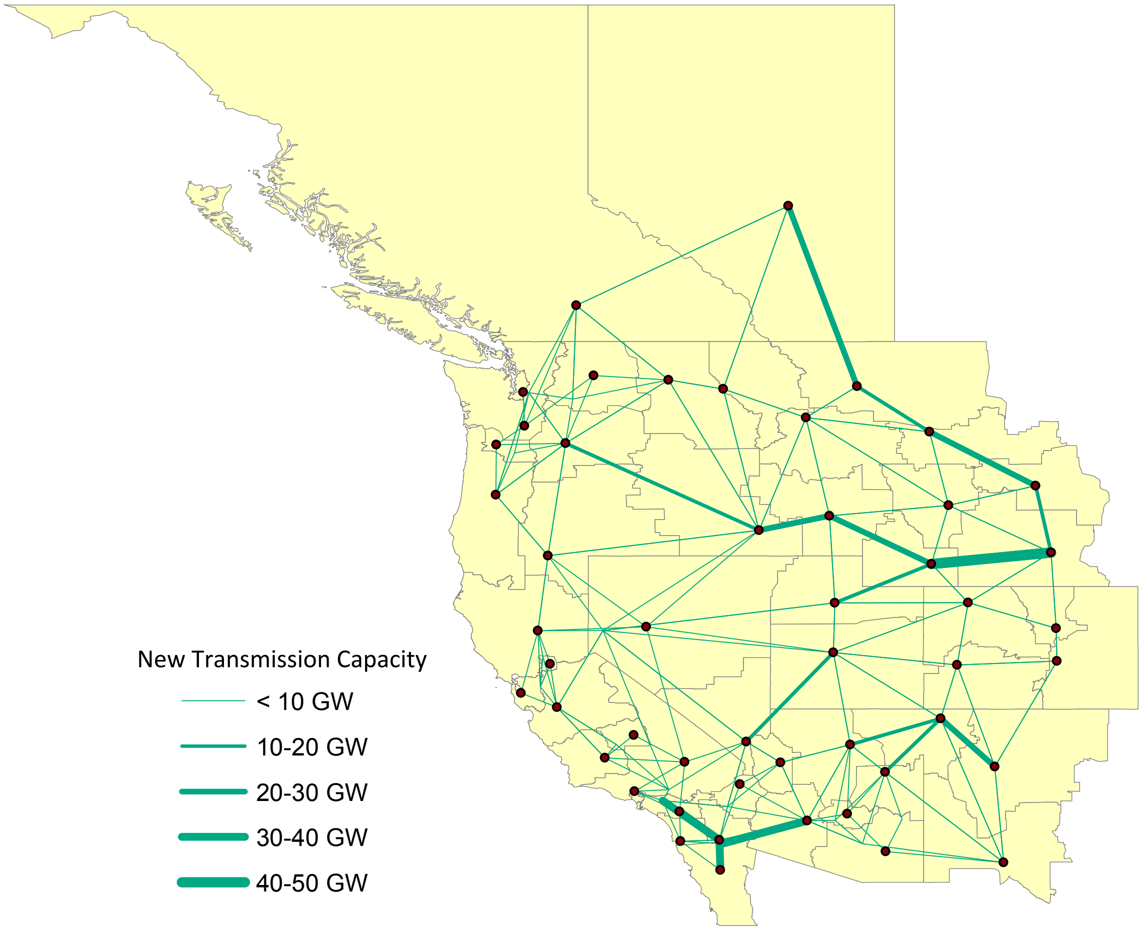


Figure 54. Map of new transmission capacity, Reference *scenario, 2050.*

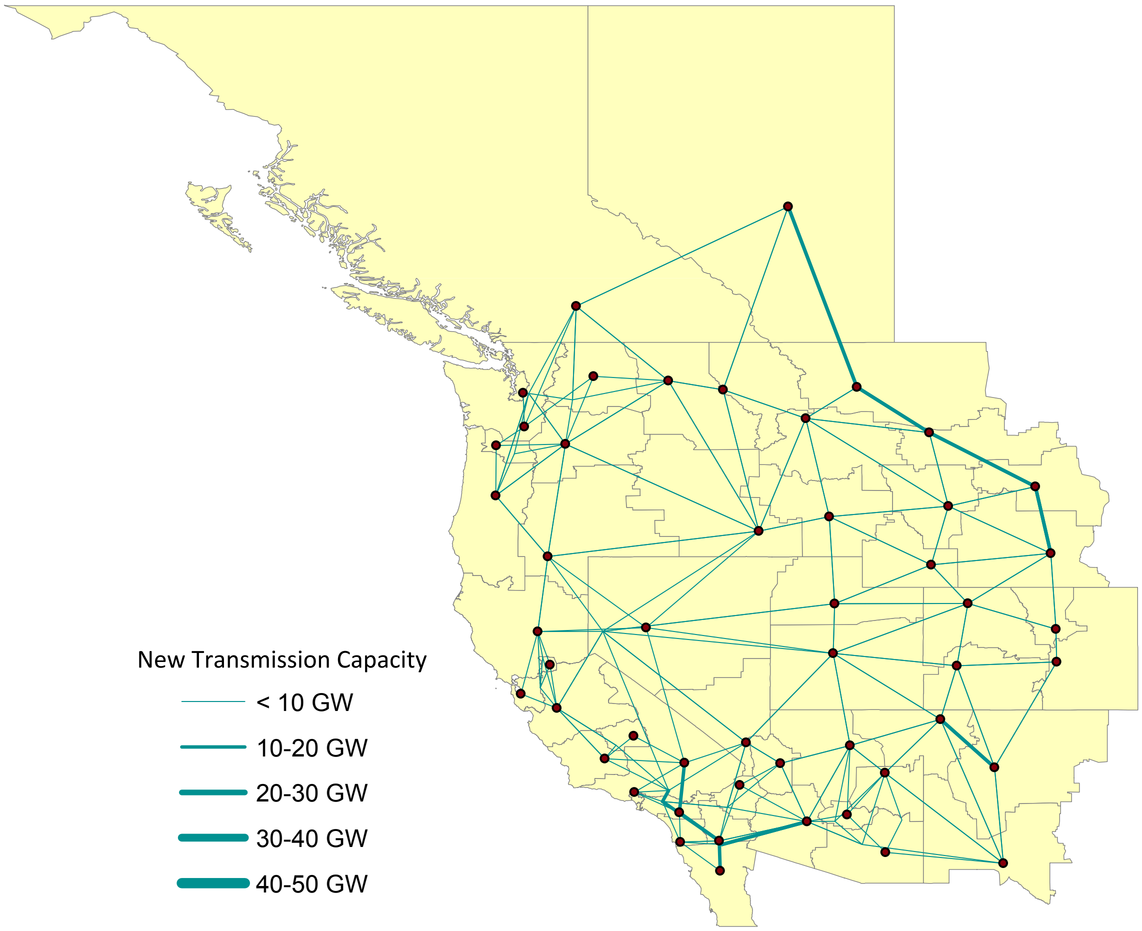


Figure 55. Map of new transmission capacity, SunShot and Low-Cost Batteries *scenario, 2050.*

3. Nuclear Power and Flexibility Requirements

In the *Nuclear and CCS* scenario, 85 GW of nuclear power are installed in the WECC. On a cost basis with the assumptions in this scenario, nuclear power becomes a dominant component of the 2050 power system. It outcompetes coal CCS technologies, another source of low-carbon baseload coal CCS technologies. Baseload geothermal built out to its full capacity of 11 GW like in all other scenarios explored here. The remaining load is met by a combination of solar PV (31 GW), wind (121 GW), and CSP with 6 hours of storage (14 GW), and 20 GW of CAES are also installed.

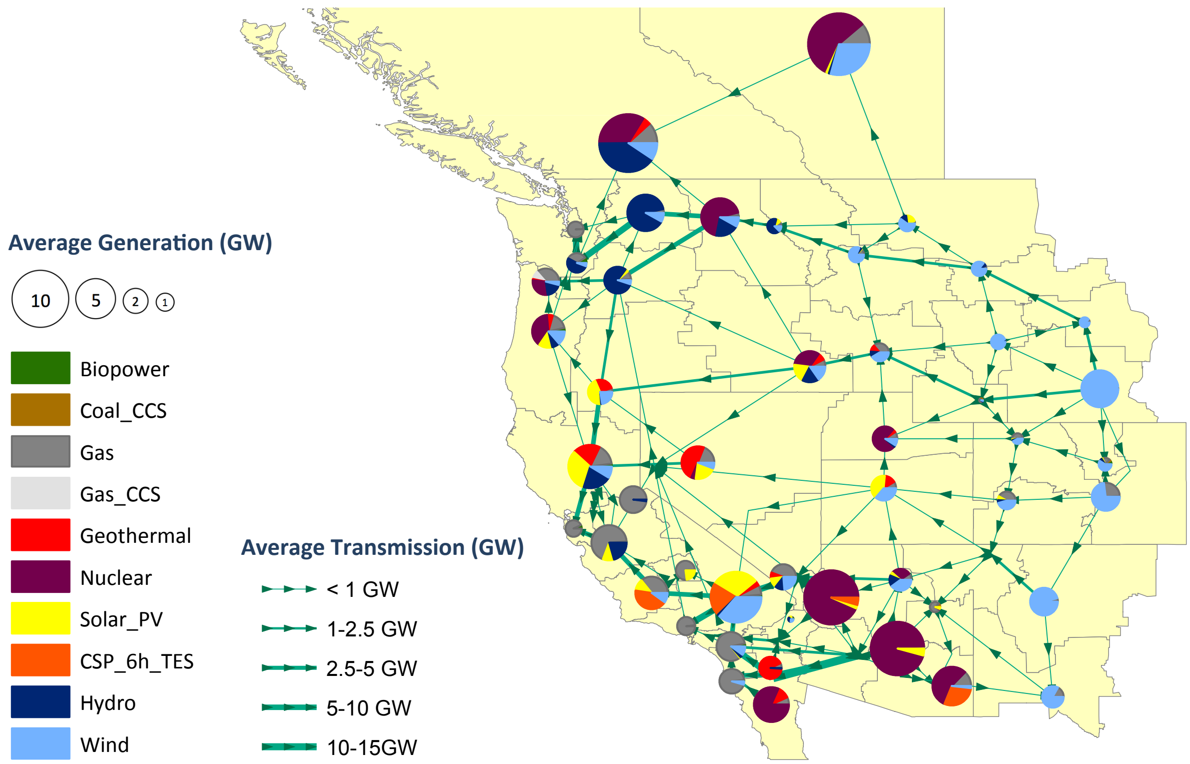


Figure 56. Map of average generation and transmission, Nuclear and CCS *scenario, 2050.*

Despite the reduction in total deployment of intermittent renewable resources relative to the *Reference* scenario, which has 69 GW of solar PV and 254 GW of wind, a similar amount of CAES is installed in the *Nuclear and CCS* case. When nuclear is available, a smaller share of load must be met by intermittent renewable sources. However, nuclear power is treated as baseload in SWITCH-WECC and operates at the same output throughout, so the remaining load exhibits large variability. The minimum level of load that must be met with non-baseload power in 2050 in the *Nuclear and CCS* scenario is 19 GW while the maximum is 148 GW (the average and median are 73 GW and 72 GW respectively). (The difference between maximum and minimum load that must be met by non-baseload power sources is about the same: in the *Reference* scenario, the minimum, maximum, average, and median load that must be met with non-baseload power are 92 GW, 221 GW, 146 GW, and 145 GW respectively.) Flexibility *is* needed in the baseload-dominated system of the *Nuclear and CCS* scenario, but a smaller total load must be met by non-baseload sources.

In the *Nuclear and CCS* scenario, the remaining load (load – baseload power) is met by a combination of gas generation, solar PV, wind, CSP with 6h of storage, CAES, and hydropower (Figure 57). CAES stores excess solar PV energy during the day and helps to meet nighttime load. It is, however, inactive for much of the year when excess wind energy is available. In the summer, wind capacity factors are low, requiring the use of natural gas generation, both intermediate and peakers, to help meet an increase in load. The installed capacity of of CSP with 6 hours of storage is reduced relative to the *Reference* scenario, but it still contributes energy in the summer during the times of highest system stress.

The feasibility of allowing large build-out of nuclear power and implications of for system cost are discussed below.

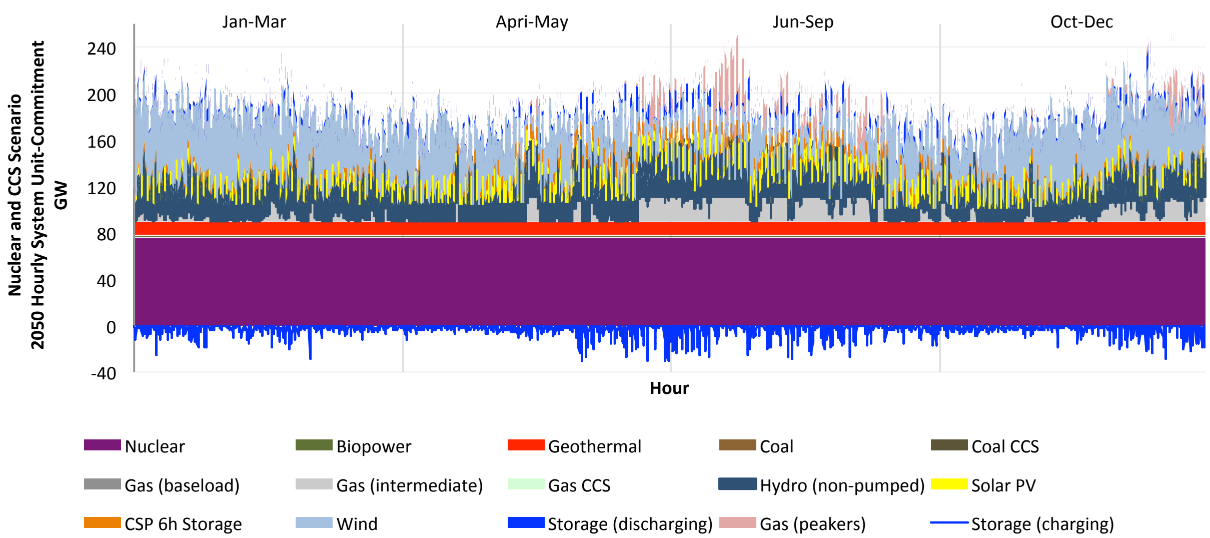
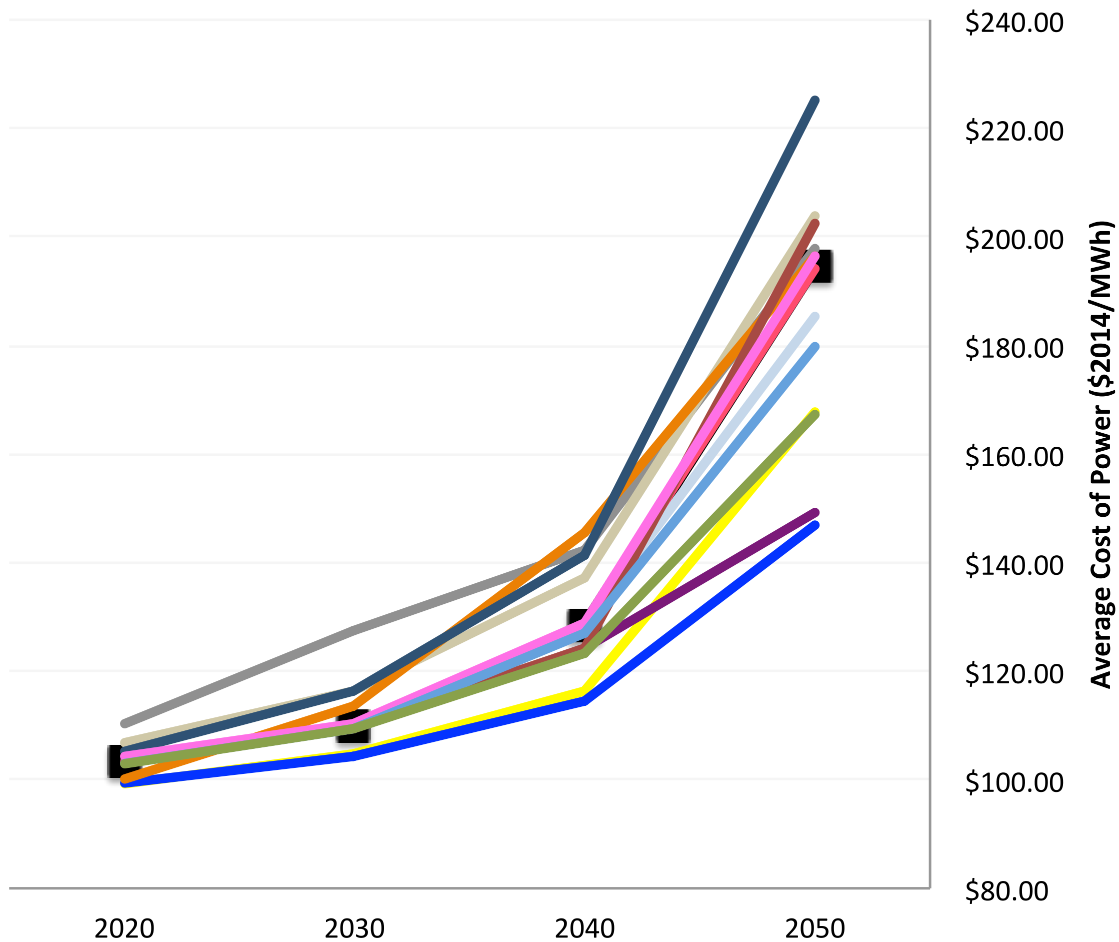


Figure 57. WECC system hourly unit-commitment, Nuclear and CCS *scenario, 2050.*

4. The Cost of the Decarbonized Power System



	2020	2030	2040	2050
Reference	$103.18	$110.07	$128.57	$194.43
SunShot	$99.26	$104.56	$116.32	$167.78
Low-Cost Batteries	$103.18	$110.06	$129.06	$185.14
High-Efficiency Batteries	$103.15	$110.00	$128.55	$194.13
SunShot and Low-Cost Batteries	$99.41	$104.49	$114.47	$146.69
High-Price Natural Gas	$110.19	$127.46	$142.13	$198.02
Methane Leakage	$106.83	$116.13	$137.30	$203.88
Nuclear and CCS	$103.24	$109.36	$124.41	$149.33
Limited Efficiency	$100.13	$113.38	$145.58	$196.70
High-Cost Transmission	$103.20	$109.65	$124.34	$202.50
Limited Hydro	$105.16	$116.12	$141.22	$225.03
Limited-Flexibility Hydro	$104.19	$110.37	$128.70	$196.54
Load-Shifting	$103.00	$109.38	$126.97	$179.78
Load-Shifting and Flexible EV Charging	$102.95	$109.17	$123.39	$167.50

Figure 58. Average cost of power through 2050 across scenarios.

4.1. *The 2030 Timeframe*

Figure 58 shows the average system cost over time in the scenarios investigated here. All costs quoted in this section are in real $2014.

Through 2030, costs stay relatively constant across scenarios. The availability of SunShot solar power results in the most pronounced decrease in costs relative to the *Reference* case, from $110/MWh to $105/MWh in the *SunShot* scenario and $104/MWh in the *SunShot and Low-Cost Batteries* scenario. On the other hand, the availability of inexpensive batteries by itself does not effect substantial cost-reductions relative to the *Reference* scenario through 2030. Similarly, the availability of flexible loads results in only a small decrease in average cost from $110/MWh in the *Reference* scenario to $109/MWh in the *Load-Shifting and Flexible EV Charging* scenario, reflecting 1) the availability of sufficient flexibility that can provide services comparable to what batteries and load-shifting provide already exists within the system in the 2030 timeframe (specifically hydro and natural gas generation) and 2) the fact that batteries and load-shifting may not be able to provide the kind of flexibility most needed by the system as the times of highest stress for the grid include extended periods of low energy availability requiring storage of longer duration.

Natural gas plays a central role in the 2030 power system because of its low emissions relative to coal, which it displaces between present day and 2030, and its ability to vary output on a seasonal basis to compensate for seasonal variations in load and renewable energy availability, particularly wind, whose deployment grows in this timeframe. The cost of natural gas infrastructure and fuel are two of largest components of power system costs, comprising more than a third of system cost in almost all scenarios (Figure 59). If the price of natural gas is doubled relative to the *Reference* scenario or its emissions are increased due to upstream methane leakage, a fraction of the gas generation that is run in baseload mode is replaced by geothermal power and larger deployments of wind and solar PV take place. The cost of the power system increases from $110/MWh in the *Reference* scenario to $116/MWh in the *Methane Leakage* scenario and to 127/MWh in the *High-Price Natural Gas* case. The latter scenario has the highest power cost in 2030: while the deployment and use of infrastructure in the two natural gas scenarios is very similar, the higher natural gas price increases total fuel costs, a major component of total power cost in the 2030 timeframe, and thus total system cost in the *High-Price Natural Gas* scenario. The need for deployment of additional infrastructure is the key factor in the increase in power cost in the *Limited Efficiency* scenario and the *Limited H*ydro scenario (Figure 59).

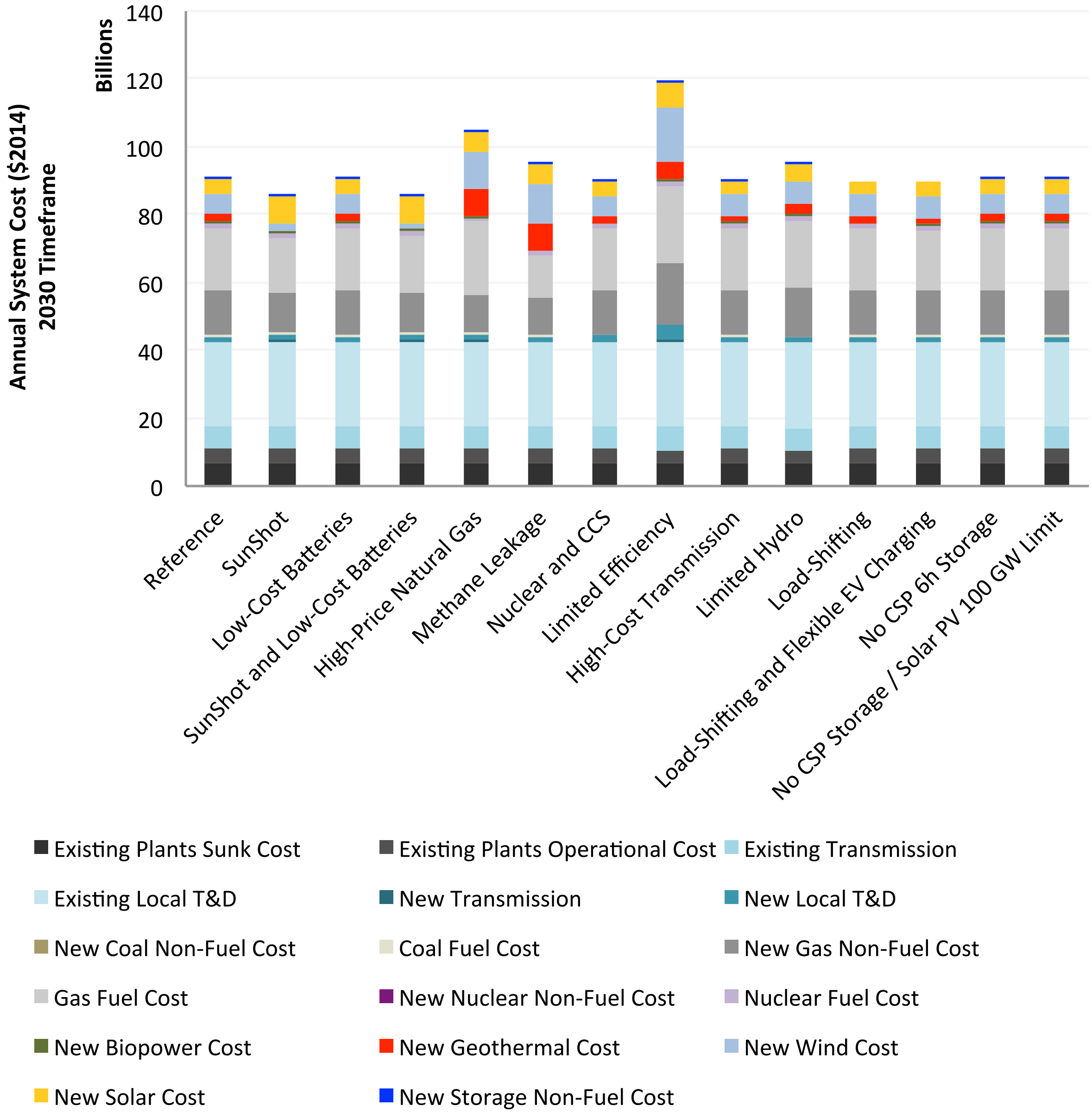


Figure 59. Total annual system cost by source and scenario in the 2030 timeframe.

4.2. The 2050 Timeframe

Across scenarios, costs continue to rise through 2040 and then increase sharply by 2050 when the system has to meet a stringent carbon cap of 85 percent below 1990 emissions levels.

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 MWh 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/MWh. Average costs in 2050 are only slightly higher in the *Limited Efficiency* scenario relative to the *Reference* scenario, but the higher total load of the latter means that the total cost of the system with limited efficiency is substantially higher (Figure 60). 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 1) the total amount of natural gas that can be used by the system is constrained by the carbon cap, 2) natural gas is very valuable to the system as it can provide flexibility on timescales ranging from the hourly to the seasonal, 3) natural gas fuel cost is a small part of system cost in this timeframe at less than 3 percent of total system cost in most scenarios (Figure 60). Limiting the amount of natural gas use further by increasing the fuel's emissions in the *Methane Leakage* scenario increases costs by 5 percent in 2050 to $204/MWh.

The *Limited Hydro* scenario that has the most expensive power on an average cost basis in 2050 at $225/MWh, reflecting the cost of additional deployment of wind and CSP with 6 hours of storage to compensate for the energy deficit resulting from lower hydro output. Total hydro output is highest in May, June, and July, and it contributes times of high system stress in July (in the *Reference* case, total hydro energy output in July is about 17 percent of total system load).

System flexibility resources – including transmission, CAES and battery storage, and CSP with 6 hours of thermal storage – become a large component of power system cost in 2050. If the price of transmission is tripled, the SWITCH investment optimization responds by increasing deployment of CSP with 6 hours of storage at the expense of wind capacity, which tends to be remote and require long transmission lines that bring the resource to load.

Low-cost flexibility is crucial to cost-containment as the power system is deeply de-carbonized through 2050. The availability of low-cost batteries or demand response push the cost of the power system down relative to the *Reference* case to $185/MWh, $180/MWh, and $168/MWh respectively in the *Low-Cost Batteries*, *Load-Shifting*, and *Flexible EV Charging* scenarios, a decrease of 5-14 percent relative to the *Reference* system. The *SunShot* scenario has even lower costs -- $168/MWh or about 14 percent lower than the *Reference* case – largely because reaching the SunShot target makes possible the cost-effective deployment of CSP with 6 hours of thermal energy storage and reduces the reliance on wind whose seasonality requires supporting infrastructure to help meet summer loads.

With the assumptions in the *Nuclear and CCS* scenario, the cost of power in 2050 is $149/MWh, 23 percent lower than in the *Reference* case. Cost estimates for nuclear power vary widely and may be substantially higher than modeled here (Bauer, Brecha, and Luderer 2012). Nuclear power also faces public acceptance challenges, so its deployment at large scale may not be politically feasible. An important finding is therefore that the *SunShot and Low-Cost Batteries* scenario has the lowest costs of all scenarios investigated here, including the *Nuclear and CCS* case. The average cost in this scenario is less than $147/MWh 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 percent lower in 2050 and also provide substantial savings in the near- and mid-term (Figure 58). While not modeled here, 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.

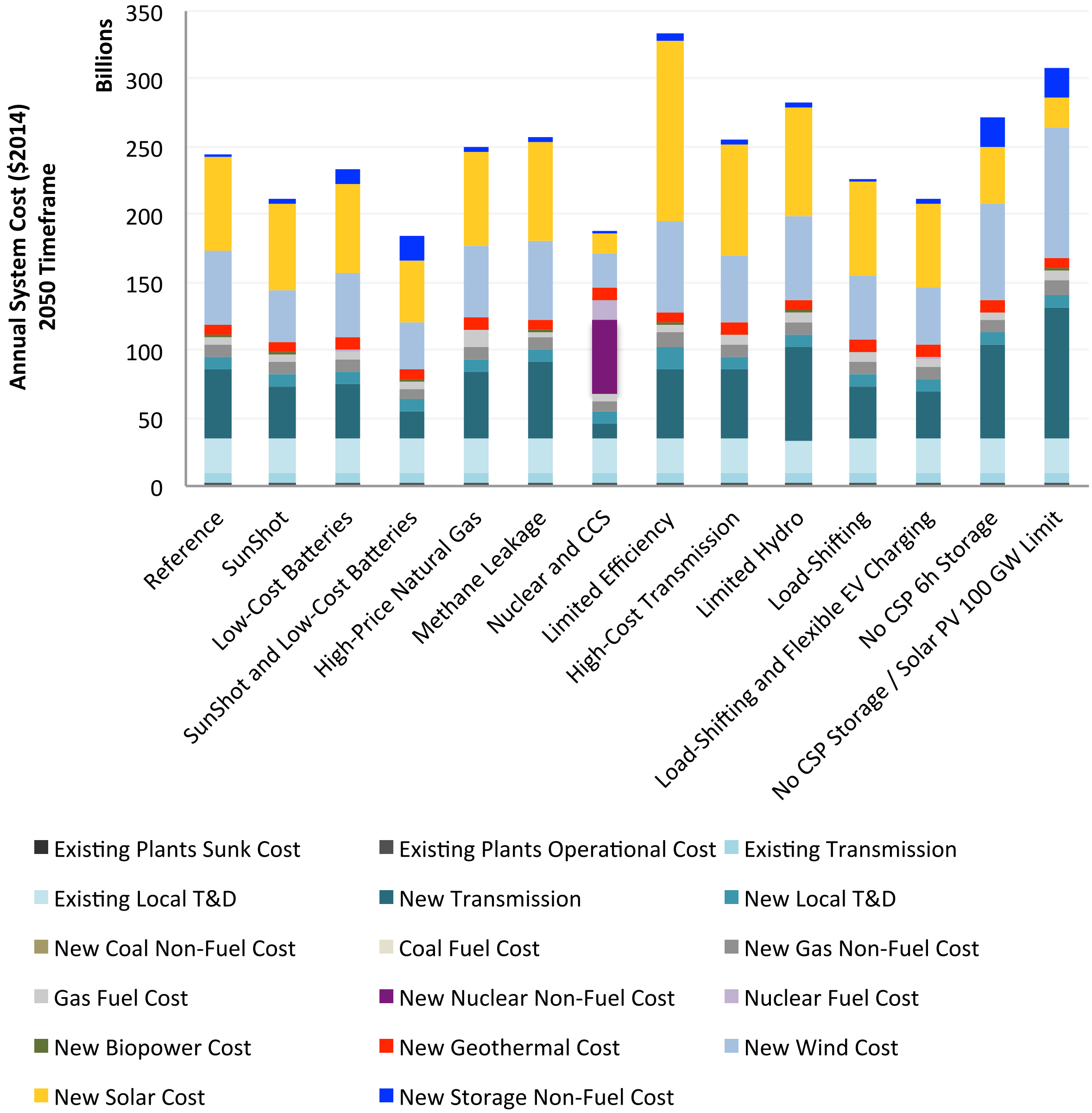


Figure 60. Total annual system cost by source and scenario in the 2050 timeframe.

VII. Conclusions and Implications For Policy

1. Current Policy Environment

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 Scoping Plan" 2014). In addition, Executive Order S-3-05 calls for a further decline in the state's emissions to 80% below 1990 levels by 2050. In this work, I explore how the electricity sector of the entire WECC electricity sector can achieve deep GHG emission reductions in the 2050 timeframe as addressing emissions beyond California is indispensable to meaningful climate change mitigation.

A number of states in the WECC already have Renewable Portfolio Standards (RPS), which require that a fraction of electricity consumed within the state to be produced by qualifying renewable generators ("Database of State Incentives for Renewables and Efficiency" 2011). The State of California has a range of other policy targets, including a goal for storage deployment: as required by California Assembly Bill 2514, the California Public Utilities Commission has directed the state's investor-owned utilities to deploy 1.3 GW of storage by 2020, including 0.7 GW of utility-scale storage.

2. Planning for System Flexibility in Low-Carbon Power Systems

2.1. Key Planning Considerations and Cost-Reduction Opportunities

The results presented here indicate that focusing on decreasing solar costs is among the most effective approaches for keeping power system costs low in the near- to mid-term timeframe as the power system begins to decarbonize. Solar power may have significant cost-reduction potential and programs are in place to reach aggressive solar cost targets by 2020 ("SunShot Initiative" 2014). Wind is a more mature technology and cost-reductions are less likely ("Cost and Performance Data for Power Generation Technologies" 2012). The main driver of storage build-out in the mid-term is solar power deployment, which in turn can be driven by a rapid decline in solar costs. Cost-reductions in battery technology may not be an effective means of containing near- and mid-term power system costs as sufficient flexibility may be available to the system from less expensive natural gas, hydro, and compressed air energy storage to integrate higher levels of solar power into the grid at medium emissions levels through 2030. As the cap becomes more stringent, low-cost battery technology has an important advantage over CAES as it is emissions-free: in the deeply decarbonized 2050 power system, emissions are very valuable and CAES use will be limited by the carbon cap.

A central finding of the work presented here is that wind and solar PV in the WECC may have different flexibility 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: its tendency to stay low or high for extended periods of time. 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 shortage. Such very-long-duration storage is not modeled here, but could be key to reducing electricity sector decarbonization costs. Conversely, solar PV has an inherent periodicity over the diurnal timescale and exhibits synergies with storage technologies designed for daily arbitrage such as compressed air energy storage and some advanced batteries. 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 subsystem component and the energy subsystem component 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. California's storage mandate only gives a power subcomponent GW target for storage deployment in the state. The timescales over which storage can operate are crucial to system design and reliable operation. Storage requirements should be set as part of overall system development goals as different decarbonization pathways have different flexibility needs. In the scenarios investigated here, energy shortages resulting from low wind output in the summer become a key feature of the system and driver of its costs by 2030. Storage with an energy subcomponent designed for the subhourly, hourly, or even daily timescale is not the appropriate technology to address these prolonged periods of energy scarcity as energy prices remain consistently high and the price differences observed during these times may be smaller than needed to justify the use of storage for arbitrage and the incurrence of storage losses.

Different storage technologies can provide different grid services, from shifting large amounts of energy over long periods of time (hours, days, or even months and seasons) to balancing the grid on much shorter timescales such as minutes or seconds. Storage policy should consider the value of each of these services – in the context of planned system development – and storage technologies' current competitiveness, setting mandates accordingly. Establishing a storage target for California would increase power system costs in the near term, but this effect is small relative to the total cost of the system. If support for *appropriate* storage technologies today helps to bring their cost down, the higher near-term cost could be counterbalanced by lower required future investment, affording a cost-effective flexibility source to the power system and making it possible to integrate higher levels of wind and solar power. As shown here, lowering the cost of storage could have widespread economic benefits and facilitate climate change mitigation.

An important question then becomes how to design policy to promote technological learning and storage cost-reductions over time. Support policy for storage deployment today should ensure that goals and performance incentives are in place to put cost pressure on system manufacturers and installers. Gradual scale-up to allow time for learning, ample opportunities to review progress, and open-information requirements to make the learning and experience of early deployers widely available are key policy features. Because storage technologies span the range of technological maturity, those that are still in the early stages of the innovation chain –

and thus may not be able to compete on a cost basis with the more mature technologies yet – may benefit from R&D funding more than from deployment incentives.

2.2. A Comprehensive Portfolio of Flexibility Options

Another important policy consideration is that storage is only one source of system flexibility. Fast-ramping generation, demand response, and flexible electric vehicle charging can provide comparable services and should be allowed to compete with storage on a level playing field as part of a comprehensive system flexibility portfolio. Better estimating demand response potential and the cost of implementation programs to assess the value to the electricity sector is a crucial area of research needs. The deeply de-carbonized electricity system of the future will likely need both storage and demand response to enable deep penetration levels of renewables by providing zero-emission balancing at the lowest cost. Additionally, continued implementation of aggressive energy efficiency to slow demand growth has been shown to be crucial in containing costs and enabling deep de-carbonization of the electric power system for climate change mitigation.

Inexpensive natural gas, if available, is of high value to the power system in the near- and mid-term as it provides relatively low-carbon resource that can address both hourly and seasonal flexibility needs. A number of questions remain about the environmental implications of fracking for shale gas. Because of the potential high value of natural gas, addressing issues such as methane leakage from the upstream supply chain and water supply contamination should be a priority to determine whether natural gas can play a large role as a “bridge” fuel.

2.3. The Benefits of a System-Wide Approach

In planning for low-carbon electricity systems, it is pivotal 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. The boundary of analysis should be over a large geographic region as the increase in flexibility requirements can be managed through geographic diversity of the renewable resource and transmission interconnection. Furthermore, considering technologies in isolation may miss critical synergies and tradeoffs among them. As most of the intermittent generation and supporting infrastructure has not been deployed yet, employing an i*nvestment* modeling framework like SWITCH is critical to finding cost-effective combinations of low-carbon resources and flexibility alternatives. However, operational detail must be incorporated to understand system dynamics and the interplay among technologies.

3. Investment Incentives and Market Design

In a de-regulated electricity policy environment with competitive wholesale energy spot markets, it is the market prices – which are based on the variable costs of the marginal generator in each time segment – that act as a signal to potential investors about the value of new assets, although energy markets without scarcity pricing can be ineffective in ensuring adequate investment in capacity (Oren 2003; Stoft 2002; Joskow and Tirole 2008). With high penetration levels of wind and solar energy, the marginal-cost pricing approach to incentivize investment may face additional challenges. The reason is that these generator types require large upfront investments but have near-zero marginal costs, thus putting downward pressure on prices and hindering all assets' ability to recover investment costs through the energy spot market unless prices rise higher at other times (resulting in higher price volatility). Furthermore, as the share of wind and solar energy in the electricity system increases, the capacity factors of conventional generation are often reduced, resulting in fewer opportunities for cost-recovery.

In the results shown here, the marginal generators is frequently one with zero marginal cost, the net load is often negative, and the annual capacity factors of natural gas generation are greatly reduced, suggesting that alternative revenue streams may be necessary to support investment unless large spikes in energy spot market prices are allowed. In the *Reference* scenario, for example, the capacity factor of CCGTs decreases from 92 percent to 32 percent between 2020 and 2050. Despite their infrequent utilization, however, the present work shows that these assets are very valuable to the electricity system due to their versatility and flexibility that can help the system maintain the balance between supply and demand at all times and ensure a planned level of reliability.

A key next step is to provide a quantification of the revenue stream available via the default market strategy and investigate other market metrics and designs appropriate for inducing investment in the categories of generation such capacity markets or "capabilities" markets (e.g. markets for flexible capacity. New market structures and policy will have to offer the additional incentives necessary for all grid assets to fully recover their costs and justify investment while providing the most value to the system and ensuring cost-effective system development over time.

4. Conclusion

Meeting climate change mitigation targets by 2050 will require both deep de-carbonization of the electric power sector and the electrification of many of the end-uses of natural gas and oil, adding substantial load from electric vehicles and heating. Recent deployment trends suggest that renewable wind and solar technologies will make a contribution to power grid decarbonization. A main challenge for these resources is that their output is variable and uncertain, and, as such, less flexible than conventional generation, posing new challenges to system operations and planning.

My PhD research seeks to incorporate operational detail into a long-term capacity-expansion model of the power system to make possible a more accurate economic evaluation of wind and solar technologies, the associated system flexibility needs, and the range of resources that can address those needs. For the purpose, I have the developed the "system flexibility module" within the SWITCH-WECC model, implementing unprecedented operational resolution in a long-term investment model of a very large geographic region. The system flexibility model has made it possible to evaluate a range of system flexibility resources in an investment framework. My focus is in particular on the need for and value of storage in electric power systems with very low greenhouse gas emission levels.

In this work, I explore a number of scenarios for deep emissions reductions from the WECC electric power sector through 2050. I find that meeting a carbon emissions reduction target of 85 percent below 2050 levels is feasible across a range of assumptions. The cost of achieving the goal is highly uncertain, but a number of opportunities to containing costs exist. Key findings include:

- In the 2030 timeframe, lowering the cost of solar technologies to the SunShot target is the main cost-reduction strategy
- Achieving the ARPA-E battery cost target has a small impact on costs in the 2030 timeframe as other sources of flexibility are available to the system, including gas generation, hydro, and CAES
- The price of natural gas is key to its utilization in the 2030 timeframe, but is not an important driver in 2050 when natural gas flexibility is of high value but its use is limited by the carbon cap
- Solar PV deployment is the main driver of CAES and battery storage deployment: its diurnal periodicity provides opportunities for daily arbitrage that these technologies are well-suited to provide
- Storage operation is very different from present day patterns – storage tends to charge during the day when solar PV is available and discharge in the evening and at night
- Similarly, the ability to shift loads to the daytime solar peak could have cost-reduction benefits for the system
- Wind output exhibits large seasonal variations; because it can remain at very low (or very high) levels for extended periods of time, it does not benefit from CAES an battery

storage (operating as providers of daily arbitrage) as much as solar and instead requires storage with a large energy subcomponent

- CSP with 6 hours of thermal storage is an important component of the 2050 power system but it directly competes with the combination of solar PV and batteries
- If low solar PV costs and low battery costs are achieved, the two technologies may be deployed at large-scale, displacing CSP with 6 hours of thermal storage
- The combination of SunShot solar technology and advanced battery technology has the largest impact on total storage capacity deployment in 2050
- A system dominated by nuclear technology can have substantial storage needs because of the inflexibility of nuclear power output and the variability in load served by other sources
- The combination of SunShot solar PV and low-cost batteries can provide substantial savings through 2050, greatly mitigating the cost of climate change mitigation
- Policy goals for storage deployment should incorporate both the power subsystem component and the energy subsystem component of energy storage
- Storage deployment requirements should be set as part of overall system development goals as system flexibility needs will vary depending on the rest of the grid mix
- Near-term support policies for storage deployment should ensure that goals and incentives are in place to put pressure on system manufacturers and installers to reduce costs over time.
- Policy should be technology-neutral and support a comprehensive portfolio of system flexibility options, allowing flexible generation, demand response, and flexible electric vehicle charging, which can provide comparable services, to compete with storage on a level playing field.
- The increase in system flexibility requirements should be managed through a system-wide approach including regional cooperation to strategically plan for transmission interconnection and geographic diversity of renewable resource deployment to mitigate the variability of overall output.
- System-level planning is critical to ensure that appropriate incentives are put in place for all grid assets to fully recover their costs and justify investment while providing the most value to the system and ensuring cost-effective system development over time

The electric power grid evolves slowly: the lead times for generation and transmission projects are long as the siting and permitting process is extensive, new infrastructure often requires multi-billion-dollar investments that amortize over several decades, and securing financing and cost-recovery can be difficult. The task of deploying high levels of renewable generation is complicated further by their intermittent nature, which calls for new operational and planning practices, and by the need to simultaneously deploy sufficient transmission and develop supporting infrastructure such as flexible generation, storage, and/or demand response. Strategic planning, coordinated actions, innovative policy and market design, and long-term policy certainty may be necessary to induce the transformative changes that will be required to drastically reduce greenhouse gas emissions while minimizing costs. With my PhD research, I have sought to contribute a deeper understanding of the pathways to decarbonization of the electricity sector and creative methods to facilitate the transition and reduce adverse energy-related environmental impacts. 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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