Title

Scenarios for Deep Carbon Emission Reductions from Electricity by 2050 in Western North America Using the SWITCH Electric Power Sector Planning Model

Author

Nelson, James Henry

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Scenarios for Deep Carbon Emission Reductions from Electricity by 2050 in Western North America Using the SWITCH Electric Power Sector Planning Model

By

James Henry Nelson

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in

Energy and Resources

in the

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of the

University of California, Berkeley

Committee in charge:

Professor Daniel Kammen, Chair
Professor Duncan Callaway
Professor Shmuel Oren

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Abstract

Scenarios for Deep Carbon Emission Reductions from Electricity by 2050 in Western North America Using the SWITCH Electric Power Sector Planning Model

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Doctor of Philosophy in Energy and Resources

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In this study we use a state-of-the-art planning model for the electric power system – the SWITCH model – to investigate the evolution of the power systems of California and western North America from present-day to 2050 in the context of deep decarbonization of the economy. We find drastic power system carbon emission reductions to be feasible by 2050 under a wide range of possible futures. The average cost of power in 2050 is found to range between $149/MWh and $232/MWh across scenarios, a 21 to 88 % increase relative to a business-as-usual scenario, and a 38 to 115 % increase relative to the present-day cost of power.

In order to rapidly decarbonize, the power system undergoes sweeping change. Between present-day and 2030, the evolution of the Western Electricity Coordinating Council (WECC) power system is dominated by the implementation of aggressive energy efficiency measures, the installation of renewable energy and gas-fired generation facilities, and the retirement of coal-fired generation. In the 2040 time frame, deployment of wind, solar, and geothermal power reduce power system emissions by displacing gas-fired generation. In the 2050 time frame this deployment trend continues for wind and solar, but is accompanied by large amounts of new storage and long-distance, high-voltage transmission capacity. In stark contrast to present-day operation, electricity storage is used primarily to move solar energy from the daytime into the night in order to charge electric vehicles and meet demand from electrified heating. Transmission capacity over the California border is increased by 40 - 220 % by 2050, implying that transmission siting, permitting, and regional cooperation will become increasingly important over time. California remains a net electricity importer in all scenarios investigated.

Wind and solar power are key elements in power system decarbonization, providing 37 – 56 % and 17 – 32 % of energy generated respectively across WECC in 2050 if no new nuclear capacity is built. In an effort to integrate wind and solar resources, the amount of installed gas capacity remains relatively constant between present-day and 2050, though carbon capture and sequestration (CCS) is installed on some gas plants by 2050. The fleet-wide average capacity factor of non-CCS gas generation drops steeply between 2030 and 2050, reaching only 5 – 16 % in 2050 for scenarios that meet the 86 % emission reduction target.

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I am very grateful for support from Link Energy Fellowship during my graduate career.

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This project would not have been possible without the groundbreaking work of Matthias Fripp on the SWITCH model. Contributions from former members of the SWITCH-WECC team are also appreciated – Ian Hoffman, Christian Blanco, and Autumn Petros-Good. I'm excited to see where future members of the SWITCH team at Berkeley will take the model.

This work builds off the California's Carbon Challenge Phase I report (Wei, et al., 2012). The work of authors on the Phase I report – Jim McMahon, Jane Long, Mike Ting, Ranjit Bharvirkar, Chris Jones, and Chris Yang – is fundamental to the analyses performed here.

I would also like to thank the policy and technical advisory committees convened for this project, as well as sponsors Guido Franco, Simone Brant, and Joe O'Hagan at the California Energy Commission. Their valuable feedback has molded much of the analysis presented here.

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GLOSSARY

Acronym	Definition
AC	Alternating Current
AEO	United States Energy Information Agency Annual Energy Outlook
AGC	Automatic Generation Control
AWEA	American Wind Energy Association
BDT	Bone Dry Ton
BioCCS	Biomass integrated combined cycle generators equipped with carbon capture and sequestration
CAES	Compressed Air Energy Storage
Cal/EPA	California Environmental Protection Agency
CANWEA	Canadian Wind Energy Association
CARB	California Air Resources Board
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Sequestration
CCST	California Council on Science and Technology
CEC	California Energy Commission
CITRIS	Center for Information Technology Research in the Interest of Society
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
CSP	Concentrating Solar Power – Solar Thermal Technology
DC	Direct Current
DNI	Direct Normal Radiation
DOE	United Stated Department of Energy
DSIRE	Database of State Incentives for Renewable Energy
EIA	United States Energy Information Administration
EPRI	Electric Power Research Institute
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GE	General Electric
GHG	Greenhouse Gas
GIS	Geographic Information Systems
GMT	Greenwich Mean Time
GW	Gigawatt
IEO	United States Energy Information Agency International Energy Outlook
IGCC	Integrated Gasification Combined Cycle
LSE	Load Serving Entity
MMBtu	Million British Thermal Units
MSA	United States Metropolitan Statistical Areas
MSW	Municipal Solid Waste

$MtCO_2$	Million metric tons of Carbon Dioxide
MVA	Megavolt ampere
MW	Megawatt
MWh	Megawatt Hour
NaS	Sodium Sulfur (battery)
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NOx	Nitrogen Oxide
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
OTC	California's Once-Through Cooling regulations
PV	Photovoltaic (solar)
RAEL	Renewable and Appropriate Energy Laboratory
REC	Renewable Energy Certificate
ROW = rest of WECC	parts of the Western Electricity Coordinating Council outside California
RPS	Renewable Portfolio Standards
SAM	National Renewable Energy Laboratory System Advisor Model
SONGS	San Onofre Nuclear Generating Station
SOx	Sulfur Oxide
SWITCH	A loose acronym for Solar, Wind, Hydro, Conventional generators, and Transmission
tCO_2	Metric Tons of Carbon Dioxide
TDY	Typical Direct Year of solar insolation
USGS	United States Geological Survey
WACC	Weighted Average Cost of Capital
WECC	Western Electricity Coordinating Council
W_p	Watt (peak) – rated capacity of generation
WREZ	Western Renewable Energy Zones
WRF	Weather Research and Forecasting mesoscale weather model
WWSIS	Western Wind and Solar Integration Study

1 EXECUTIVE SUMMARY

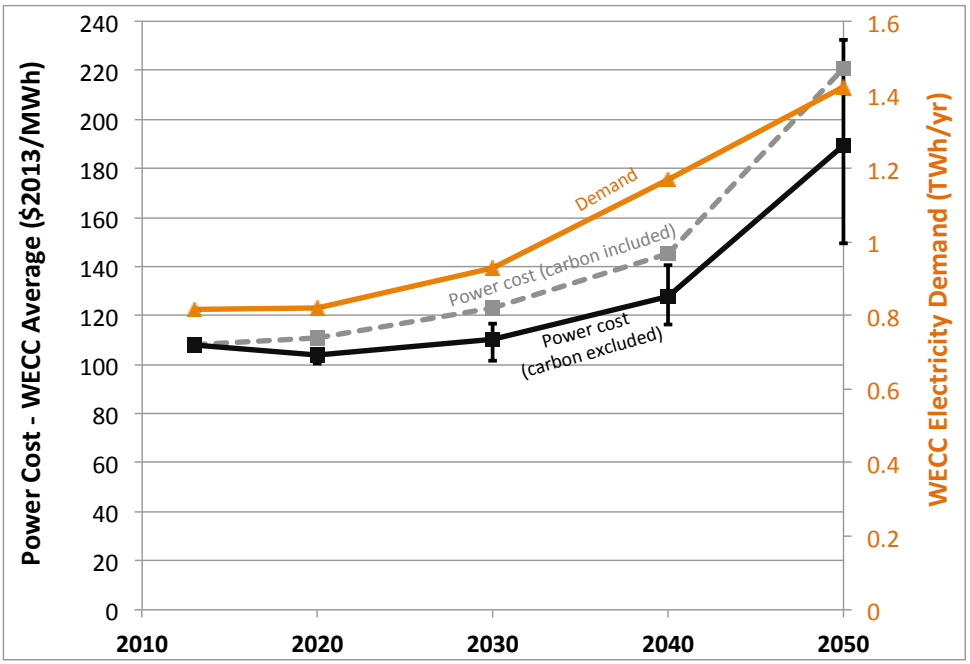
In this study we use a state-of-the-art planning model for the electric power system – the SWITCH model – to investigate the evolution of the power systems of California and western North America (specifically WECC, the Western Electricity Coordinating Council) from present-day to 2050 in the context of deep decarbonization of the economy. As the cost of electricity is an important factor for the economic welfare of society, cost-minimization framework is employed. We simulate how projected electricity demand, reliability requirements, and policy goals might be met at the lowest possible cost. The power system is constrained to reach 14 % of 1990 CO_2 emission levels by 2050 under a range of scenarios, each with specific assumptions about future demand profiles, costs, policy mandates, technological availably, and electric system flexibility.

The electricity system is of fundamental importance to the decarbonization of the entire energy system, as fuel switching away from oil and natural gas and towards electricity is a key decarbonization strategy. The scenarios presented here incorporate hourly electricity demand profiles resulting from the electrification of heating and vehicles, as well as from substantial energy efficiency. Even with aggressive efficiency measures, WECC-wide electricity demand is likely to increase by at least 75 % between present-day and 2050 (Figure 1-1) due to population growth and additional demand from electric vehicles and electric heating.

The results presented here should be interpreted in the context of the economic optimization from which they are generated. They do not represent prescriptions or projections but rather they depict minimum-cost strategies for a range of possible scenarios that meet policy targets while also supplying reliable electricity.

We find drastic power system carbon emission reductions to be feasible by 2050 under a wide range of possible futures. Assuming that carbon permit revenues are reinvested into the power system, the WECC-wide average cost of power in 2050 is found to range between $149/MWh and $232/MWh across scenarios. This power cost level represents a 21 to 88 % increase relative to a business-as-usual scenario in which emissions stay flat after 2020, and a 38 to 115 % increase (in real terms) relative to the present-day cost of power. As this study assumes little technological progress by default in many parts of the electricity system, these cost estimates may represent an upper bound. We demonstrate that breakthroughs in the cost of solar energy or the deployment of demand response could contribute greatly to containing the cost of electricity decarbonization.

Figure 1-1: WECC average power cost and electricity demand by investment period in the Base Scenario

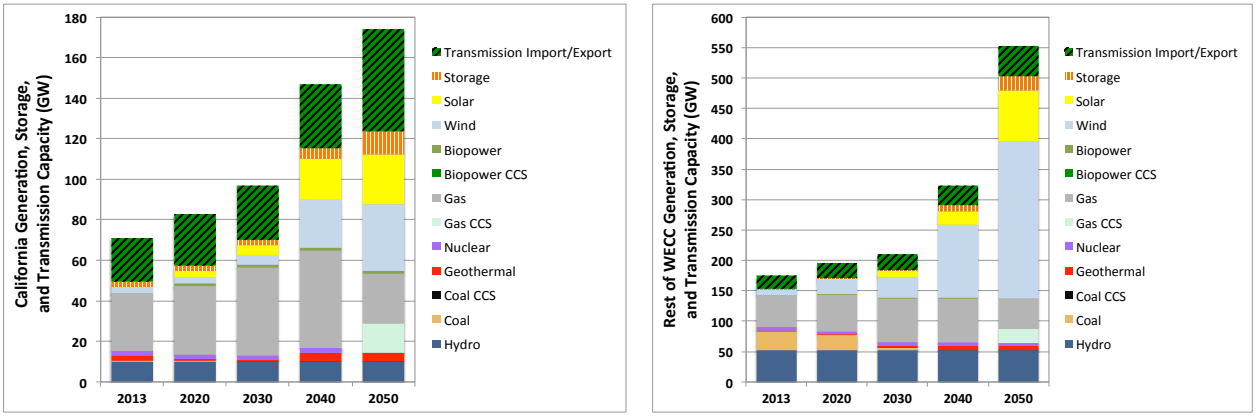


The power cost with 'carbon included' differs from that with 'carbon excluded' by the cost of carbon permits. The error bars represent the range of power costs (with carbon excluded) found in scenarios other than the Base Scenario.

In order to rapidly decarbonize, the power system undergoes sweeping change. Between present-day and 2030, the evolution of the WECC power system is dominated by the implementation of aggressive energy efficiency measures, the installation of renewable energy and gas-fired generation facilities, and the retirement of coal-fired generation (Figure 1-2). In the 2030 time frame, the flexibility provided by the existing transmission network, existing hydroelectric facilities, the geographic consolidation of balancing areas, and a large fleet of gas-fired generation units is largely sufficient to integrate 45 - 86 GW of wind and solar power capacity in WECC, representing 12 - 21 % of total electricity produced. Consequently, deployment of new storage or long-distance, high-voltage transmission capacity is shown not to be a dominant strategy through 2030. Transmission capacity into California, made available in part by the retirement of out-of-state coal generation, is dominated by renewable power in the form of bundled Renewable Energy Certificates (RECs) in the 2030 time frame. The cost of power stays almost constant until 2030 – despite demand growth and reduction in emissions – due to moderate gas prices, the expiration of existing generator sunk costs, and the development of high quality renewable resources.

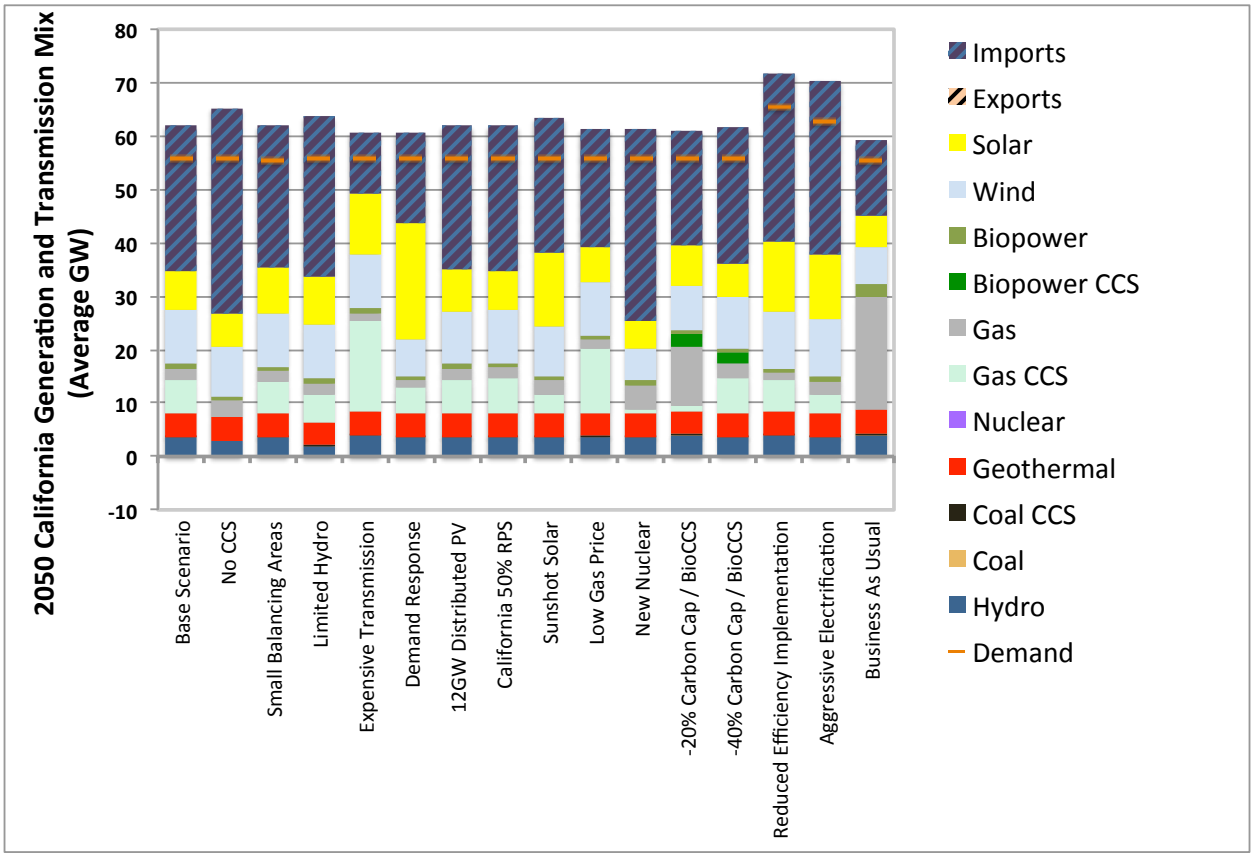
Near- to mid-term renewable energy policy targets – either a 12 GW distributed generation mandate in California by 2020 or a California 50 % RPS by 2030 – can help to deploy renewable generation in California on an accelerated schedule. However, these policy targets have less effect on the generation mix in the 2040 to 2050 time frame, as the cap on carbon emissions is the dominant driver of renewable energy deployment post-2030.

Figure 1-2: Base Scenario generation capacity, storage capacity, and transmission import/export capacity across the California border as a function of investment period in California and the rest of WECC



Transmission import/export capacity is the same magnitude on both plots.

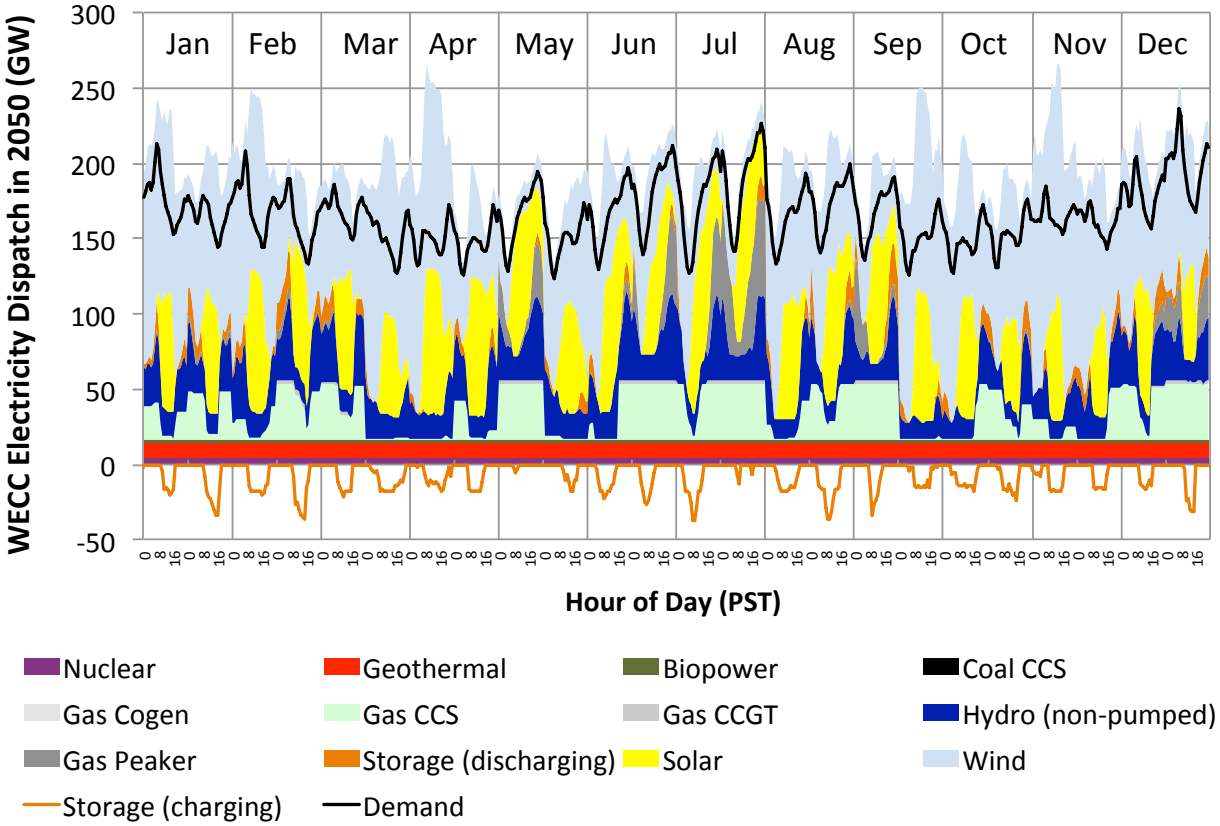
Figure 1-3: California average hourly generation mix by fuel, imports and exports, and demand in 2050 for all scenarios



A similar figure for the rest of WECC can be found in the main text (Figure 4-4). California remains a net importer in all scenarios.

Post-2030, the electricity system undergoes a radical transformation in order to eliminate almost all carbon emissions from the generation mix. In the 2040 time frame, deployment of wind, solar, and geothermal power reduce power system emissions by displacing gas-fired generation. In the 2050 time frame this deployment trend continues for wind and solar, but is accompanied by large amounts of new storage and long-distance, high-voltage transmission capacity. In stark contrast to present-day operation, electricity storage is used primarily to move solar energy from the daytime into the night in order to charge electric vehicles and meet demand from electrified heating (Figure 1-4). Low-cost solar power is found to increase the need for electricity storage. If demand response is deployed in large scale in this time frame, it substitutes for the functionality of storage, thereby strongly incentivizing the deployment of solar generation, especially in California.

Figure 1-4: Base Scenario hourly power system dispatch across WECC in 2050

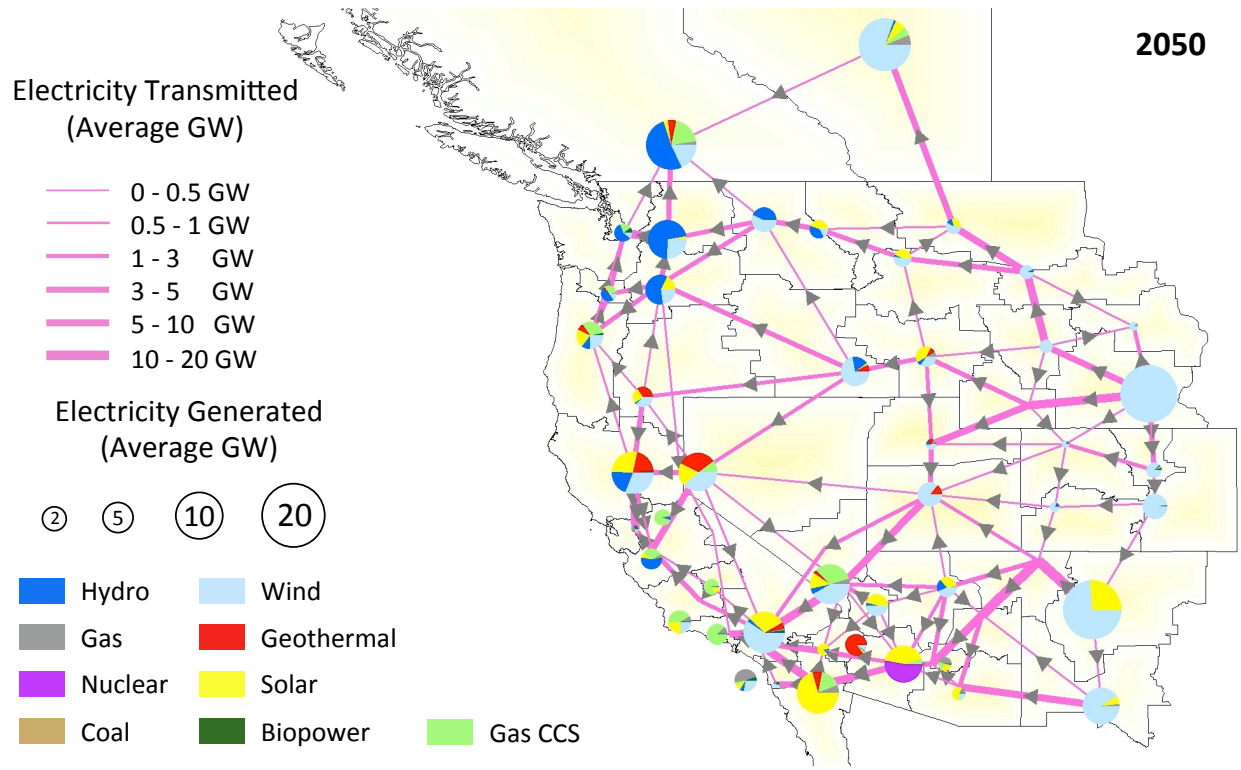


Two days per month are represented – the median demand day and the day on which the hour of peak demand occurs. Total generation exceeds demand due to distribution, transmission, and storage losses, as well as variable renewable energy curtailment. Plots of specific days can be found in the main text in Figure 4-13.

Through 2050, transmission lines that exist today are found to be mostly sufficient to move power between Pacific Coast states. New transmission capacity is built primarily to move power over hundreds of miles from the inside of the continent towards demand centers on the coast. High-voltage DC transmission may be well suited to provide much of this new

transmission capacity. Transmission capacity over the California border is increased by 40 - 220 %, implying that transmission siting, permitting, and regional cooperation will become increasingly important over time. California remains a net electricity importer in all scenarios investigated. The percent of electricity imported into California ranges from 22 % to 60 %, with most scenarios resulting in imports of about 40 %. The implementation of demand response programs could reduce the necessary import/export capacity into California. The deployment of out-of-state nuclear power or a lack of availability of Carbon Capture and Sequestration (CCS) technology would require high levels of California transmission import/export capacity.

Figure 1-5: Base Scenario average hourly generation mix by fuel within each SWITCH load area, and average hourly transmission flow between load areas in 2050



Wind and solar power are key elements in power system decarbonization, providing 37 – 56 % and 17 – 32 % of energy generated respectively across WECC in 2050 if no new nuclear capacity is built. At these penetration levels of variable renewable energy, the least cost strategy for meeting policy, reliability, and demand targets includes the curtailment of wind, and to a lesser extent solar facilities at hours of high renewable output and/or low electricity demand (Figure 1-3). In this study, transmission and storage are installed to capture energy from variable renewable facilities, but there is an economic trade-off between building additional storage and transmission facilities or slightly over-sizing renewable power facilities such that there is ample energy from these facilities in hours of great need. Curtailment of some variable renewable power becomes the lowest-cost strategy under the aggressive carbon targets investigated in this study. Demand response can help to reduce curtailment, but does not entirely eliminate

curtailment. Consequently, determining how the cost of variable renewable curtailment is compensated will become increasingly important over time.

In an effort to integrate wind and solar resources into the power system, the amount of installed gas capacity remains relatively constant between present-day and 2050 (Figure 1-2), though CCS is installed on some gas plants by 2050. The fleet-wide average capacity factor of non-CCS gas generation drops steeply between 2030 and 2050, reaching only 5 % to 16 % in 2050 for scenarios that meet the 86 % emission reduction target, indicating that gas plants are only operated for a handful of hours each year but are of extremely high value during those few hours. This result suggests the difficulty of supporting gas generation through energy and ancillary service market revenues, and implies the need for other revenue streams such as a capacity market. As there is little space in the carbon cap for fossil fuel emissions by 2050, sub-hourly spinning reserves are almost exclusively provided by hydroelectric and storage facilities.

Both gas-fired CCS and nuclear power are found to be economical in the context of deep emission reductions, but neither is found to be essential to meeting 2050 emission targets. Both technologies are subject to large political and/or technical uncertainty and therefore economics may not be the driving force for installation. The deployment of moderate amounts of flexible gas CCS to balance variable renewable generation is found to be one of the most effective ways to contain the costs of reducing carbon emissions, especially in California. Gas CCS is not found to be economical to run in baseload mode due to the prevalence of inexpensive wind and solar power, as well as incomplete emissions capture by the CCS system. Coal-fired CCS is not deployed at scale in any scenario investigated due to unfavorable economics and incomplete emissions capture. The finding that baseload fossil fueled CCS is not economical at deep carbon reduction levels is counter to the prevailing thinking about CCS and follows directly from using a detailed modeling platform such as SWITCH.

Biomass CCS can be effective at reducing power sector emissions far below zero by 2050, and can therefore be thought of as a hedge against incomplete decarbonization of other sectors (notably the transportation sector). The cost to make the power system net carbon negative is moderate if biomass is made available to the electric power system instead of to the production of biofuels.

2 THE SWITCH MODEL AS IMPLEMENTED IN THIS STUDY

2.1 INTRODUCTION AND MOTIVATION FOR MODELING FRAMEWORK

Text adapted from (Wei, et al., 2012).

It is likely that future low carbon electricity systems will rely on variable renewable generation sources such as solar and wind power. The variability of wind and solar can pose challenges for power systems in which a large fraction of electricity originates from these sources. Construction of large-scale electricity storage and transmission capacity can aid in the integration of variable renewables. In order to determine ideal candidate investments, significant temporal and spatial resolution is needed in electricity planning models.

Traditional power system planning models and processes encounter difficulties with the spatially and temporally complex nature of variable renewable resources, as the temporal and spatial components of hour-to-hour and day-to-day power system operations have been largely abstracted from the planning process. Candidate portfolios of generation, transmission, energy efficiency, and to a lesser extent demand response and electricity storage, are evaluated by detailed hourly or sub-hourly operational models in the planning process. However, the development of the composition of these portfolios has not traditionally been as sophisticated (Mills & Wiser, 2012; Mai, Drury, Eurek, Bodington, Lopez, & Perry, 2013).

In addition, the traditional planning process has generally considered a relatively slowly changing generation landscape, allowing planning on the 10-year time frame to be sufficient even though many electric sector investments have a 20 to 60 year lifespan. If almost all carbon emissions from the electricity system are to be eliminated by 2050, the planning process must incorporate the fast rate of infrastructure change between present-day and 2050 implied by such a drastic transformation. Incorporating long-term carbon reduction mandates into the planning process will help to reduce the cost of emission reductions by eliminating erroneous investments in carbon-emitting power system infrastructure.

The importance of the power system planning process is highlighted in the following quote from (Williams, et al., 2012):

"If electricity does become the dominant component of the 2050 energy economy, the cost of decarbonized electricity becomes a paramount economic issue. […] These findings indicate that minimizing the cost of decarbonized generation should be a key policy objective."

In an effort to minimize the cost of transitioning to a decarbonized power system, the SWITCH model operates on many different spatial and temporal scales. SWITCH uses spatially resolved, time-synchronized hourly demand and renewable generation profiles in a capacity-planning model. The contribution of baseload, dispatchable and variable renewable generation options alongside storage and transmission capacity are determined on a least-cost basis while ensuring that future electricity demand is met reliably. The model concurrently optimizes investment in and dispatch of power system infrastructure, an approach that allows for proper valuation of variable renewable capacity over a wide range of possible power system configurations. While

precise limitations of the future transmission system are not calculated here, the utilization of transmission lines is limited to realistic levels by a novel derating technique. Renewable portfolio standard and carbon cap constraints are considered simultaneously with investments such the dependence of policy mandates on the valuation of power system infrastructure build-out is explicitly evaluated.

In this study, SWITCH is used to examine many possible scenarios in which the electric power system of California and western North America undergoes a sweeping reduction in carbon emissions between present-day and 2050. The results of these scenarios precede a complete description of the model formulation in acknowledgment that most readers are likely to be interested in the conclusions of the study rather than the methodology. However, the reader may find it helpful to refer to appendices devoted to the description of data sources and model formulation in order to understand the context in which the results are created. We decide to forgo a summary and conclusions section at the end of the results section in favor of the executive summary above.

The SWITCH electric power system planning model was created at the University of California, Berkeley by Dr. Matthias Fripp (Fripp, 2008; Fripp, 2012). The version of SWITCH used in this study is maintained and developed by Ph.D. students James Nelson, Ana Mileva, and Josiah Johnston in Professor Daniel Kammen's Renewable and Appropriate Energy Laboratory (RAEL) at the University of California, Berkeley. Previous publications from RAEL include: (Nelson, et al., 2012; Wei, et al., 2012; Wei, et al., 2013; Mileva, Nelson, Johnston, & Kammen, 2013). Many improvements have been made to the modeling framework and scenario assumptions since the first phase of this project (Wei, et al., 2012) that have substantially impacted the modeling results. A discussion of these changes and their impact can be found in Appendix C : Improvements from Phase I and Their Implications.

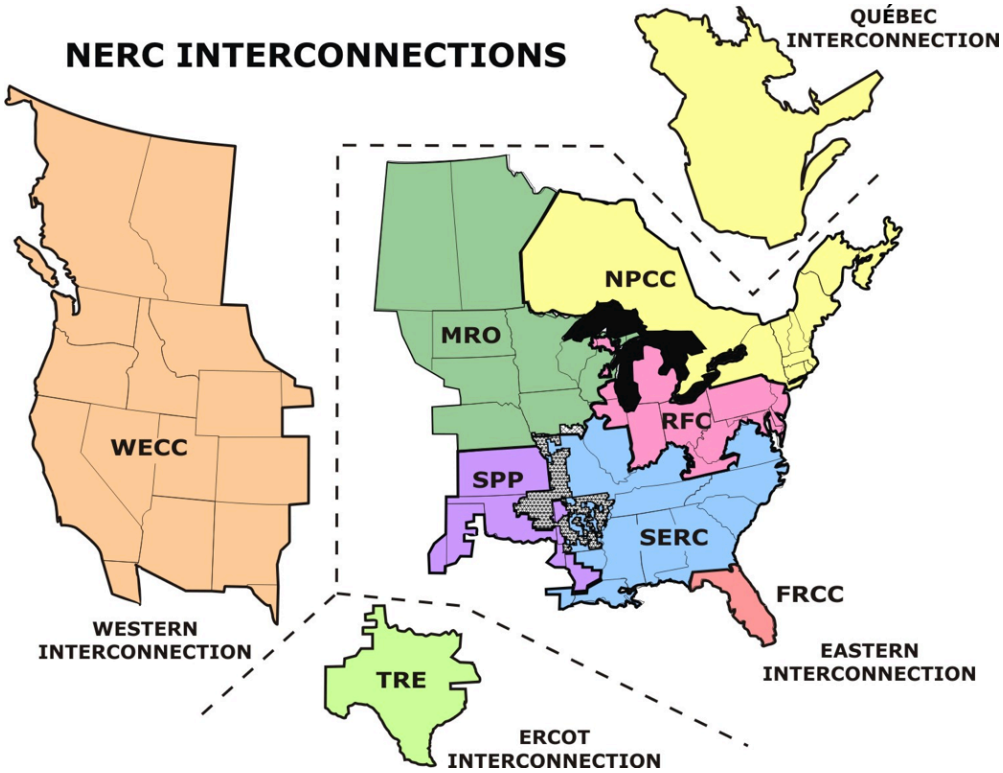
2.2 GEOGRAPHIC SCOPE

The SWITCH model as implemented in this study encompasses the synchronous region of the Western Electricity Coordinating Council (WECC), which extends east-west from the Pacific coast of North America to the eastern border of Colorado, and north-south from the Canadian provinces of British Columbia and Alberta to Arizona and the Mexican state of Baja California Norte. As suggested by Figure 2-1, little electricity is moved across interconnection boundaries. WECC therefore is modeled in this study as a self-contained electricity system with no trading between other interconnections.

While this study focuses on the state of California, it is important to consider regions outside California with respect to future electricity production. California currently represents approximately one third of electricity demand in WECC, and imports hydroelectric power from the Pacific Northwest as well as coal and nuclear power from the Desert Southwest. These imports may change over time, and it is therefore important to explicitly model all of WECC in order to account for interactions between California and the rest of the region. However, the SWITCH modeling framework is not presently able to account for many local and state-level policies and preferences that can change the build-out of the electricity system. An example of

this is the recent drive in California to build in-state solar power. Consequently, the results must be understood in the context of substantial WECC-wide coordination to reduce power system costs and carbon emissions.

Figure 2-1: North American Electric Reliability Corporation regions



Source: (NERC, 2013).

In the version of SWITCH used in this study, WECC is divided into 50 'load areas,' within which power is generated and stored, and between which power is transmitted (Appendix A.1.1). Twelve of these 50 load areas are in California. Load areas represent regions of electricity demand within WECC. In addition, load areas correspond to parts of the existing electric power system within which there is significant transmission and distribution infrastructure, but between which limited long-range, high-voltage transmission currently exists. Consequently, load areas are regions between which new transmission may be needed.

2.3 SWITCH-WECC CAPABILITIES AND LIMITATIONS

In Table 2-1 we provide a high-level summary of SWITCH-WECC model capabilities and limitations. A complete description of the model can be found in the appendices.

Table 2-1: Capabilities and limitations of the SWITCH model as implemented in this study.

Category	Currently, SWITCH can:	Currently, SWITCH cannot:
Model uses	Create long-term investment plans that meet load, reliability requirements, operational constraints, and policy goals using projected technology costs. A simplified hourly dispatch algorithm within the investment framework captures aspects of wind and solar variability and mitigation measures for such variability	Perform detailed mixed-integer unit commitment to simulate day-to-day grid operations
Geographic extent and resolution	Model the Western Electricity Coordinating Council (WECC): California, Oregon, Washington, Idaho, Montana, Utah, Wyoming, Nevada, Colorado, Arizona, New Mexico, Baja California Norte, British Columbia, Alberta	Import or export power from the eastern United States or eastern Canada
	Model 50 load areas or "zones" in the WECC within which demand must be met and between which power is sent	Perform bus or substation level analysis
Technology options	Operate existing generation and storage infrastructure within operational lifetimes	
	Retire existing generation infrastructure	
	Install and operate conventional and renewable generation capacity using projected fuel and technology costs. Natural gas fuel costs are modeled with price elasticity	Determine economy-wide fuel prices
	Install and operate storage technologies with multiple hours of storage duration for power management services	Install and operate storage technologies with shorter storage duration
	Use supply curve for biomass to deploy bioelectricity plants	Determine the optimal ratio of biomass allocation between electricity and other end uses (notably biofuels for transportation)
Transmission network	Install new transmission lines and operate new and existing lines as a transportation network. Transmission path limits that approximate transmission system operational constraints are enforced	Enforce DC or AC power flow, stability, or contingency constraints for the transmission network
Distribution network	Maintain existing distribution capacity and build new distribution capacity to meet peak demand in each load area	Simulate detailed distribution system dynamics or economics
Demand	Meet hourly demand forecasts in 50 WECC load areas through 2050. Energy efficiency, electric vehicles, and heating electrification demand forecasts are disaggregated.	Evaluate optimal levels of energy efficiency or electrification of transportation and heating
	Dispatch demand response subject to pre-specified resource availability	Evaluate optimal levels of demand response procurement
Reliability	Ensure load is met on an hourly basis in all load areas	Account for sub-optimal unit-commitment due to forecast error; include treatment of electricity market structures
	Maintain spinning and non-spinning	Explicitly balance load and generation on the

Category	Currently, SWITCH can:	Currently, SWITCH cannot:
	reserves in each sub-regional balancing area in each hour to address contingencies	sub-hourly timescale, maintain regulation reserves, model system inertia or Automatic Generation Control (AGC)
	Maintain a 15 % capacity reserve margin in each load area in each hour	Address issues of catastrophic risk and blackout resilience
Operations	Cycle baseload coal generation on a daily basis and enforce heat-rate penalties for operation below full load	Enforce coal ramping constraints or allow coal plants to shut down on a seasonal basis
	Enforce startup costs and part-load heat-rate penalties for intermediate generation such as combined cycle gas turbines (CCGTs)	Perform detailed unit-commitment
	Enforce startup costs for combustion turbine peaker plants	Perform detailed unit-commitment
	Shift demand within a day using projections of demand response potential	
	Operate hydroelectric generators within water flow limits	Model detailed dam-level water flow or environmental constraints
Policy	Enforce Renewable Portfolio Standards (RPS) at the load-serving entity level using bundled Renewable Energy Certificates (RECs)	Model tradable RECs, enforce NOx and SOx limits
	Enforce a WECC-wide carbon cap or carbon price that varies over time	Provide global equilibrium carbon price or warming target; assess leakage or reshuffling from carbon policies; enforce state-level carbon caps
	Enforce the California Solar Initiative (CSI) and other distributed generation targets	Assess incentives for distributed generation
	Calculate costs that must be recovered from consumers	Determine rate structures to recover costs
Environmental Impacts	Exclude sensitive land from project development	Enforce local criteria air pollutant constraints
	Deploy concentrating solar power (CSP) with air-cooling to minimize water impacts	Enforce local water constraints
Uncertainty	Perform deterministic, scenario-based planning	Perform stochastic planning; develop robust optimization plans using multiple scenarios

2.4 COST AND FUEL PRICE INPUTS

The assumed capital, operational, and fuel costs of generation, storage, and transmission projects are fundamental drivers in each SWITCH optimization. SWITCH is an optimization model that seeks to minimize the cost of meeting demand, reliability, and policy constraints. The benefits of installing an infrastructure project are weighed against the cost of that project in order to find the best set of investments. In Table 2-2, cost inputs are broken up by the spatial and temporal scales over which they are incurred.

Table 2-2: Cost and fuel price inputs to SWITCH in this study.

Temporal / Spatial	**Decadal** (Investment Period)	**Daily** (Peak and median day of each month in the Investment Optimization; 365 days in the Dispatch Optimization)	**Hourly** (or 4-hourly in the Investment Optimization)
Entire WECC system	• Generator, storage, transmission, and distribution base capital and fixed O&M costs • Natural gas wellhead price supply curve • Nuclear fuel price • Carbon price (if enabled)		
Sub-region	• Non-bio fuel prices • Natural gas price regional adjustment • Sunk transmission and distribution costs • New base distribution costs		
Load areas	• Generator, storage, transmission, and distribution local adjustment to base capital and fixed O&M cost • Grid connection of non-sited generation (new bio, natural gas, nuclear, coal, storage) • New non-sited baseload fuel and variable O&M • Bio solid fuel price supply curve	• New flexible baseload (coal) fuel and variable O&M	• New dispatchable generation fuel and variable O&M • New combined cycle startup costs • New and existing storage variable O&M
Existing generator or storage projects; new wind, solar, or geothermal projects	• Existing generator and storage sunk costs • Existing baseload fuel and variable O&M • Grid connection of sited generation (wind, solar, geothermal)	• Existing flexible baseload (coal) fuel and variable O&M	• Existing dispatchable generation fuel and variable O&M • Existing combined cycle startup costs

O&M is short for 'Operations and Maintenance' costs.

2.5 INDEPENDENT VARIABLES

Independent variables represent the various options that are available to the SWITCH optimization in order to satisfy demand, reliability, and policy constraints. The installation of physical ("in the ground") power systems infrastructure over time is controlled by capacity investment decision variables. These can be found in the 'Decadal (Investment Period)' column of Table 2-3. The utilization of physical power systems infrastructure is controlled by dispatch decision variables found in the 'Daily' and 'Hourly columns of Table 2-3. Choices are made in every study hour or every study day about how to dispatch generation, storage, transmission, and demand response via the dispatch decision variables.

Table 2-3: Independent variables optimized by SWITCH in this study.

Temporal / Spatial	**Decadal** (Investment Period)	**Daily** (Peak and median day of each month in the Investment Optimization; 365 days in the Dispatch Optimization)	**Hourly** (or 4-hourly in the Investment Optimization)
Entire WECC system	• Natural gas consumption (derived)		
Sub-region			
RPS areas (roughly load serving entities)			• Transmit renewable energy certificate • Surrender renewable energy certificate
Load areas	• Capacity installed of non-sited new generation and storage (gas, coal, bio, nuclear, storage) • New baseload output • Transmission and distribution capacity • Biomass solid consumption (derived)	• New flexible baseload (coal) power output	• New dispatchable generation power output and operating reserve commitment • New combined cycle unit commitment • Storage charge and discharge • Demand response load shifting • Transmission dispatch
Existing generator or storage projects; new wind, solar, or geothermal projects	• Retire or operate existing generator • Exiting baseload power output • New wind, solar, or geothermal capacity installed	• Existing flexible baseload (coal) power output	• Existing dispatchable generation power output and operating reserve commitment • Existing combined cycle unit commitment

2.6 CONSTRAINTS

The constraints of SWITCH can be thought of as the requirements that must be met in each optimization in order to meet policy targets while reliably operating the power system. The optimization can meet these requirements with different combinations of decision variables (Section 2.5: Independent Variables) and it must pick the values of decision variables that minimize the total power system cost (Section 2.4: Cost and Fuel Price Inputs) over the next 40 years.

Each constraint will have a corresponding long-run marginal cost in the investment optimization. SWITCH investment optimizations calculate long-run instead of short-run costs because the model can make infrastructure investments that change the shape of the short-run supply curve. The interpretation of long-run marginal costs can be quite different from that of short-run costs – in a present-day short-run framework in California, gas-fired generation is typically on the margin because it has the highest variable costs of any generation unit. However, if investment decisions are allowed, then virtually any generator can be on the margin, including those with zero variable costs such as wind and solar, as long as the total system cost induced by installing that generator is the smallest of any option available at the margin. The long-run costs calculated by SWITCH include not only the cost to install and operate a generation unit, but also costs related to delivering electricity generated to the point of demand via transmission and storage.

Table 2-4: Constraints in version of SWITCH used for this study.

Temporal / Spatial	**Decadal** (Investment Period)	**Daily** (Peak and median day of each month in the Investment Optimization; 365 days in the Dispatch Optimization)	**Hourly** (or 4-hourly in the Investment Optimization)
Entire WECC system	• Carbon emission compliance • Natural gas supply curve price-consumption limits		
Sub-region	• California distributed renewable target compliance • Regional generator exclusions		• Operating reserve compliance
RPS areas (roughly load serving entities)	• RPS compliance		
Load areas	• Installed capacity limit of non-sited new generation (bio, compressed air energy storage) • Solid biomass supply curve price-consumption limits • Baja California Norte export limit	• Storage, demand response, and hydro energy balance	• Meet demand • Meet capacity reserve margin • Generator, storage, and transmission capacity limits • Demand response limits
Existing generator or storage projects; new wind, solar, or geothermal projects	• Installed capacity limit of sited generation (existing generator or storage; new wind, solar, or geothermal)		• Existing generator or storage project capacity limits

3 DESCRIPTION OF SCENARIOS

3.1 CARBON EMISSIONS CAP

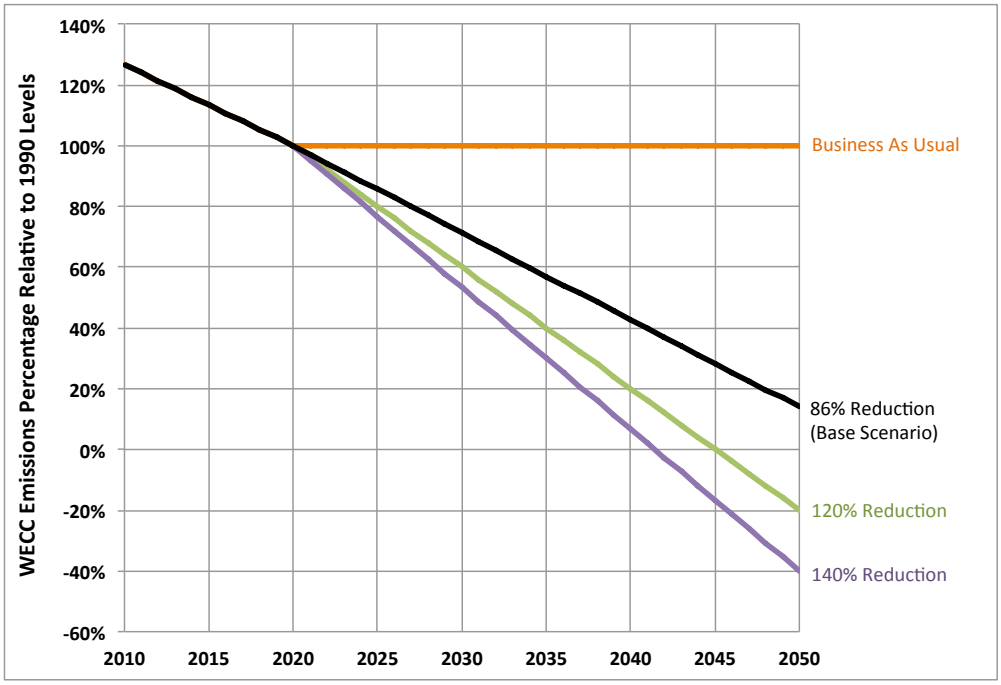
In this study we investigate the decarbonization of the WECC electricity system over time. 2050 is chosen as an endpoint for all scenarios investigated as it represents the time frame in which global carbon emissions must be drastically reduced in order to reduce the likelihood and magnitude of negative effects of climate change. On a local level, Governor Schwarzenegger's Executive Order S-3-05 requires California to reduce greenhouse gas (GHG) emissions to 80 % below 1990 levels by 2050. As there is large uncertainty about many of the drivers of electricity sector infrastructure deployment, we take a scenario-based approach to investigate different future possibilities with respect to the power system.

In this study the "rest of WECC" (the parts of WECC outside California) is assumed to be decarbonizing the electric grid at the same rate as and in conjunction with California. Trading of carbon emission permits is therefore implicitly assumed between all of the states and provinces in WECC. While we recognize that this does not reflect the current policy paradigm, it is likely that there will be future impetus to reduce carbon emissions in the rest of WECC. Renewable portfolio standards already exist in many western states, and existing coal-fired generators are slowly being retired. New coal generation capacity without carbon capture and sequestration is unlikely to be built as federal carbon emission standards loom large. As this study investigates the very long-term implications of carbon emission reductions on the electric power system, the likely appearance of various carbon reduction policies provides weight to the idea of enforcing a WECC-wide carbon cap in the future. We do not examine scenarios in which the rest of WECC does not follow the same emission trajectory as California. This represents an important topic that could form the basis of further study.

We investigate four different possible carbon emission trajectories in the WECC electric power sector (Figure 3-1). In the *Base Scenario* and most other scenarios, we cap the total carbon emissions from the WECC power system in the year 2050 at 86 % below the 1990 emissions baseline of 285 $MtCO_2$/yr. The emissions level allowed in 2050 is therefore (1 - 0.86) * 285 $MtCO_2$/yr = 40 $MtCO_2$/yr. We assume a linear decrease in carbon emissions from present-day until 2020, reaching 100 % of 1990 levels in 2020. Further declines between 2020 and 2050 are taken on a linear declination schedule that meets the 2050 cap. We do not currently treat non-CO_2 greenhouse gas emissions from the power sector in SWITCH.

The only scenarios that differ in carbon cap magnitude from the 86 % cap are the *Business-As-Usual Scenario* (Section 3.12) and the Biomass CCS scenarios (Section 3.11).

Figure 3-1: WECC emissions trajectories over time that are investigated in this study



The 86 % target is chosen in part because it represents a more aggressive target for the electricity sector relative to the economy-wide 80 % reduction target. Recent research (CCST, 2011; Williams, et al., 2012; Wei, et al., 2012; Wei, et al., 2013) has highlighted that decarbonization of the power system is likely to be easier than that of other sectors (importantly the transportation sector), and thus the power system should have a more aggressive target than the rest of the economy. This difference in sectoral targets can be thought of as a way to equilibrate the price of carbon emissions between different sectors in absence of a modeling framework that explicitly models economy-wide carbon trading.

The 86 % target is also chosen because it is the lowest target for the electricity sector that the SWITCH modeling team believes can be represented with sufficient accuracy in the current model framework. The timescales of variability introduced by variable renewable energy (wind and solar power) – from sub-second to multi-year – present major challenges to existing power system capacity planning models. The geographical diversity of renewable resources also requires treatment of the transmission system in planning models. The ability to model all relevant temporal and spatial scales is not currently possible in a single optimization platform and is an active area of research. SWITCH is currently able to assess carbon emissions from electricity on timescales ranging from sub-hourly to yearly, while simultaneously considering the need for new high-voltage, long-distance transmission. The 2050 carbon emissions and generation mix quoted in this study are the result of simulating the WECC power system based on one year of hourly variable renewable output and demand data, broken down into independent blocks of 24 hours (one day). We therefore do not explore monthly or seasonal energy storage except for existing hydroelectric capacity, which is operated subject to historical monthly limits and is therefore not an independent variable with which to balance monthly or

seasonal variability. The 86 % value chosen arises from the most difficult scenario to model with SWITCH from an emissions perspective – the *No CCS Scenario*. In this scenario, generators do not have the option of including carbon capture with sequestration (CCS) technology, and both new nuclear and bioelectricity power plants are not allowed to be installed. Pushing the *No CCS Scenario* beyond 86 % reductions would have, in the opinion of the modeling team, not satisfactorily reflected the cost of meeting deeper emissions reductions without CCS, new nuclear, or bioelectricity.

3.2 BASE SCENARIO ASSUMPTIONS

We define a base scenario for the electric power sector of WECC that is believed to contain assumptions that are, in aggregate, neither aggressive nor conservative in the context of drastic carbon emission reductions. A complete discussion of the data, assumptions, and model formulation that drive the *Base Scenario* can be found in the appendices. Key assumptions are explored via many different sensitivity scenarios. These deviations from *Base Scenario* assumptions will be discussed in subsequent sections of this chapter.

Table 3-1: Base Scenario assumptions that will be varied in sensitivity studies.

Parameter	Base scenario defaults that will be varied for sensitivity scenarios
Carbon cap (WECC-wide)	100% of 1990 emissions levels in 2020 Linear decrease beyond 2020 to 86% below 1990 emission levels in 2050
Generation fleet	Carbon capture and sequestration (CCS) included
	New biomass excluded from electric power
	New nuclear excluded (existing nuclear given option to run)
	Solar (and most other generation and storage) costs as projected by Black & Veatch
	Hydropower at historical (2004-2011) average generation levels
Gas price	NEMS Annual Energy Outlook Base Case 2012
Transmission cost	$1,130 per MW of thermal capacity per km
Policy	12 GW distributed generation mandate in California not included
	33% Renewable Portfolio Standard (RPS) in California in 2020 included; higher RPS targets in California not included
Demand profile	Electrification of heating and vehicles
	Widespread energy efficiency implementation
Demand response	Disabled
Sub-hourly reserve balancing	NERC sub-regional level: 6 regions across WECC

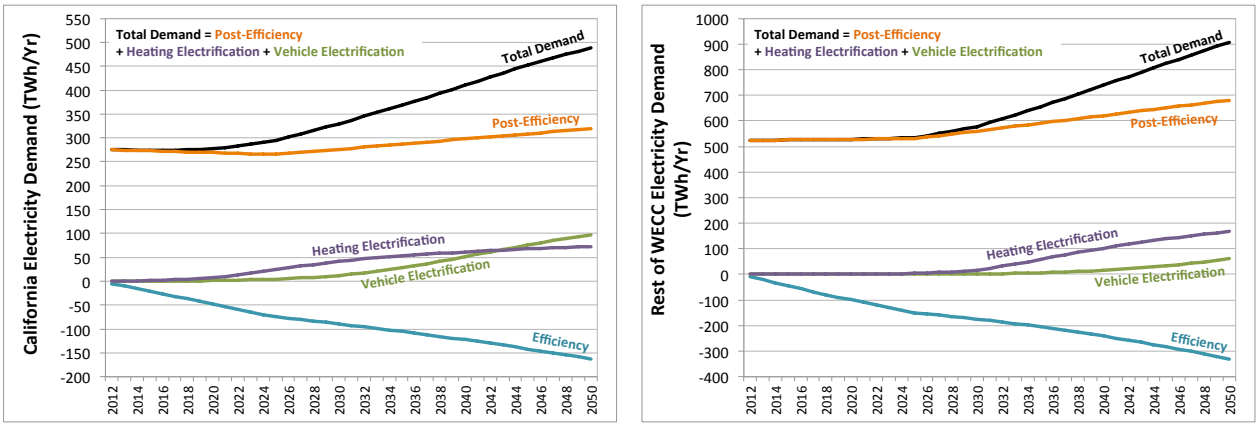
3.3 BASE SCENARIO DEMAND MAGNITUDE AND PROFILE

Hourly demand data from 2006 is used as the base year for all demand profiles. The hourly magnitude of demand over all 8760 hours of 2006 is modified in future years by the

introduction of energy efficiency measures, vehicle electrification, and heating electrification. Due to the prominent position of energy efficiency in the California loading order and the importance of energy efficiency in meeting GHG emission reduction goals (Wei, et al., 2012), we include the widespread implantation of energy efficiency measures in the *Base Scenario*. Figure 3-2 shows that energy efficiency allows post-efficiency demand to remain roughly flat, which in the context of increasing population represents a decrease in per capita electricity consumption over time. We recognize that level of energy efficiency found in the *Base Scenario* differs from that found in the California Energy Commission (CEC) demand forecast (CEC, 2013), and we therefore also model a *Reduced Efficiency Implementation Scenario* in which only 50 % of the efficiency measures included in the *Base Scenario* are implemented.

A more detailed discussion of demand magnitude and profile can be found in a forthcoming Lawrence Berkeley National Laboratory report, as well as (Wei, et al., 2012).

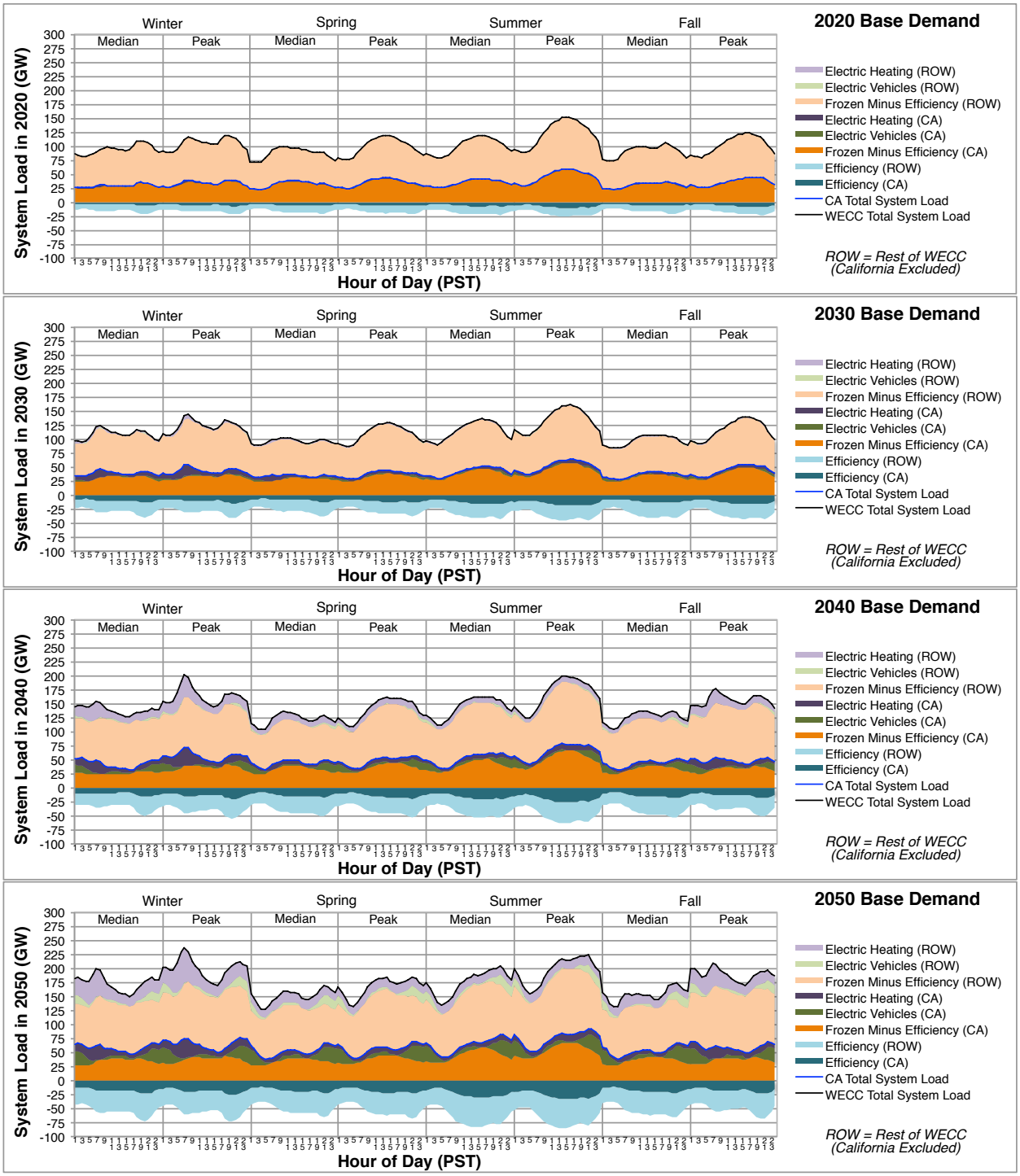
Figure 3-2: Demand over time for California and the rest of WECC, divided into demand categories



The black 'Total Demand' line represents the input demand into SWITCH. 'Post-Efficiency' represents the non-electrification demand after efficiency measures have been taken. The 'Efficiency' line represents the cumulative effect of efficiency measures over time and thus is depicted as a negative demand. The frozen efficiency demand projection from which efficiency measures are taken is not shown, but can be reconstructed by adding the absolute value of 'Efficiency' to 'Post-Efficiency'.

As shown in Figure 3-3, drastic shifts in demand profile between 2020 and 2050 are seen from the implementation of efficiency and addition of demand from electric vehicles and heating. Note that an early morning demand peak in winter appears by 2050. This peak does not currently occur in the present-day WECC-wide demand profile.

Figure 3-3: Base demand profiles by decade



"Total System Load" represents the demand profile input into SWITCH. One peak and one median demand day per season are shown in the figure for clarity, though SWITCH uses six days per season for each decadal investment period. "Frozen Minus Efficiency" represents the demand profile after efficiency measures have been implemented, but before any heating or vehicle electrification.

3.4 SCENARIOS MATRIX

Table 3-2: Scenarios for the electricity system investigated in this study

Scenario name	Demand profile	Electricity supply options	Policy options	System flexibility	2050 WECC electricity carbon cap (vs. 1990)
Base	Base	Base	Base	Base	14%
No CCS	Base	**CCS unavailable**	Base	Base	14%
Small Balancing Areas	Base	Base	Base	**Load-area level operating reserves**	14%
Limited Hydro	Base	Base	Base	**Linear decrease to 50% hydro energy by 2050**	14%
Expensive Transmission	Base	Base	Base	**Expensive new transmission**	14%
Demand Response	Base	Base	Base	**Aggressive demand-shifting**	14%
12 GW Distributed PV	Base	Base	**12 GW distributed PV in California by 2020**	Base	14%
California 50% RPS	Base	Base	**50% RPS in California by 2030**	Base	14%
SunShot Solar	Base	**SunShot solar costs**	Base	Base	14%
Low Gas Price	Base	**Low natural gas price**	Base	Base	14%
New Nuclear	Base	**New nuclear allowed outside California**	Base	Base	14%
-20% Carbon Cap / BioCCS	Base	**BioCCS included, new biomass allowed**	Base	Base	**-20%**
-40% Carbon Cap / BioCCS	Base	**BioCCS included, new biomass allowed**	Base	Base	**-40%**
Reduced Efficiency Implementation	**Reduced efficiency implementation**	Base	Base	Base	14%
Aggressive Electrification	**Aggressive heating and vehicle electrification**	Base	Base	Base	14%
Business-As-Usual	**Frozen efficiency and minimal electrification**	**New nuclear allowed outside California & new biomass allowed**	Base	Base	**100%**

3.5 DEMAND MAGNITUDE AND PROFILE SENSITIVITIES

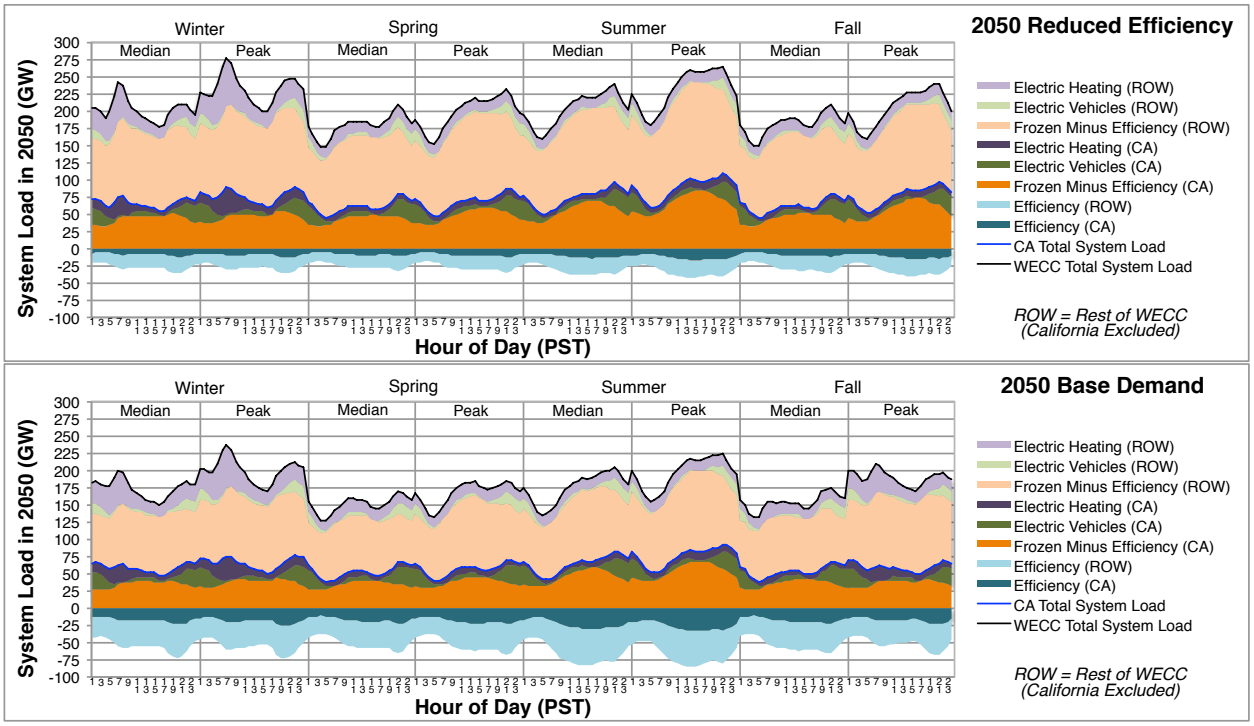
3.5.1 REDUCED EFFICIENCY IMPLEMENTATION

The *Base Scenario* includes reduction in demand from widespread energy efficiency implementation, thereby assuming that installation of a fleet of energy efficiency technologies will occur. These technologies are commercially available today, but may or may not have reached cost-effectiveness. California has prioritized energy efficiency over the installation of new generation capacity through the loading order, and we assume that the installation of high levels of energy efficiency measures will occur in the future. Future technological innovation in energy efficiency could provide further potential for demand savings, but is not modeled here.

The *Reduced Efficiency Implementation Scenario* explores the possibility that widespread efficiency is not achieved across a wide range of end-uses. In this scenario, electricity savings from energy efficiency are assumed to be 50 % of that found in the *Base Scenario* for every end-use across WECC, excluding electrified heating and vehicles. We assume a 20 % increase electric space heating demand, reflecting the possibility that building shells may not achieve technical potential efficiency. Little increase in water heating efficiency relative to present-day is assumed in the *Base Scenario*, so decreased efficiency implementation in electric water heating has negligible impact. The increase in space heating demand equates to a 10 % increase in total electric heating demand in 2050 relative to the *Base Scenario* because electric heating is split roughly equally between space and water heating. We do not assume increased demand from inefficient electric vehicles in this scenario.

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

Figure 3-4: Demand profile in 2050 for the Reduced Efficiency Implementation Scenario

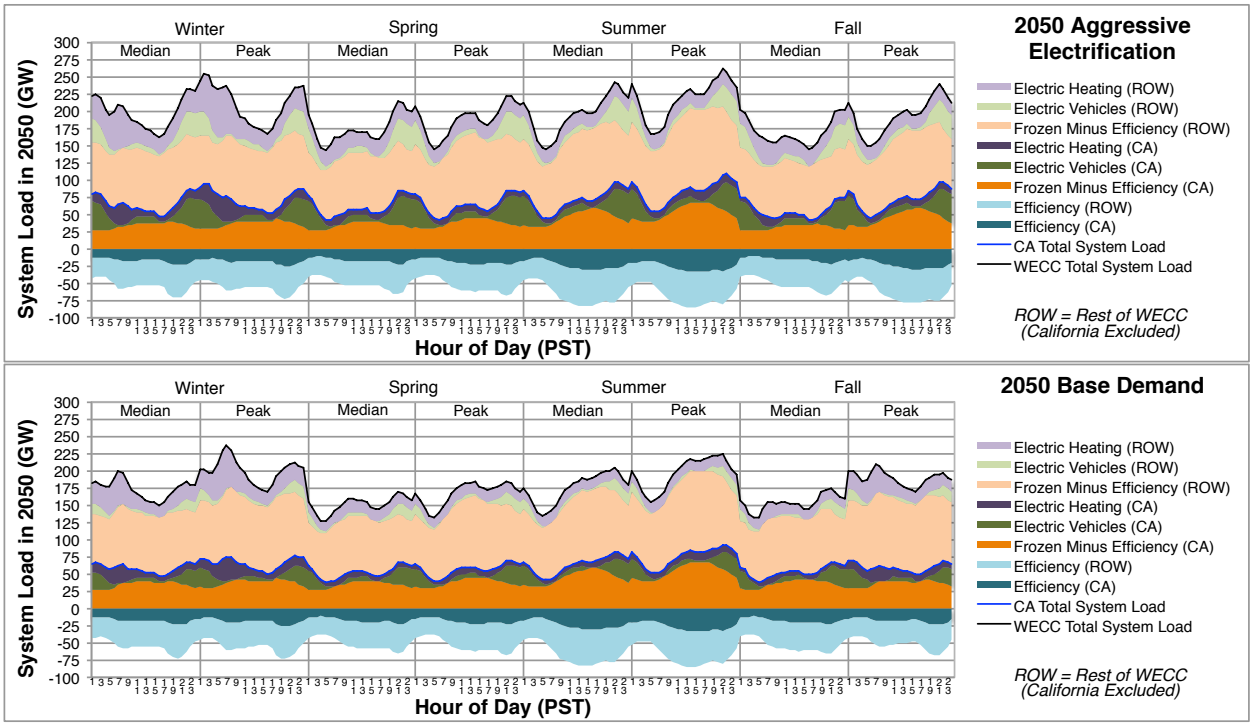


The Base Scenario demand profile is included for comparison.

3.5.2 AGGRESSIVE ELECTRIFICATION

If electrification is embraced as the leading economy-wide greenhouse gas emission reduction strategy, there could be substantially more electricity demand from electric transportation and heating by 2050 than is included in the *Base Scenario*. The *Aggressive Electrification Scenario* includes 77 % increased vehicle and 22 % increased heating demand relative to the *Base Scenario* in 2050. This represents an additional 173 TWh of demand that must be supplied by the electricity system while still reducing carbon emissions to the level of the *Base Scenario* – 14 % of 1990 levels by 2050.

Figure 3-5: Demand profile in 2050 for the Aggressive Electrification Scenario



The Base Scenario demand profile is included for comparison.

3.6 DEMAND RESPONSE

The *Demand Response Scenario* explores the possibility that GW-scale, inter-hourly demand shifting may be available to the power system in the 2050 time frame. In all scenarios but the *Demand Response Scenario*, demand response is not included and electricity demand is therefore static. This assumption should not be taken to mean that demand response does not have an important part to play in future power systems. Rather, the modeling team did not have access to data on the long-term price and availability of demand response by end-use category. In an effort to draw conservative conclusions about the difficulty of integrating variable renewable energy into the power system, we did not want to rely on a resource for which we had little information regarding the cost and magnitude of potential. In order to create a scenario with substantial demand response, in the *Demand Response Scenario* we assume that demand response is costless both to call upon and to procure. Results from this scenario therefore reflect a world in which demand response is inexpensive to procure in the long-term, representing a bounding case that explores a potentially very valuable resource.

Demand response potentials for different end uses were estimated for each decade, as described in Section A.5: Demand Response Hourly Potentials and summarized in Table 3-3.

Table 3-3: Demand response potential in the Demand Response Scenario

Year	Residential and Commercial		Electric Vehicles		Total	
	WECC-wide Average Hourly Moveable Potential (MW)	Average Moveable Percentage of Hourly Total Demand	WECC-wide Average Hourly Moveable Potential (MW)	Average Moveable Percentage of Hourly Total Demand	WECC-wide Average Hourly Moveable Potential (MW)	Average Moveable Percentage of Hourly Total Demand
2020	236	0.3%	118	0.1%	354	0.4%
2030	2414	2%	1544	2%	3958	4%
2040	8688	7%	7537	6%	16255	12%
2050	16498	10%	18016	10%	34514	20%

3.7 REDUCED FLEXIBILITY SCENARIOS

3.7.1 EXPENSIVE TRANSMISSION

The ability to build new transmission from areas of high variable renewable resource to demand centers is important to the integration variable renewable generation. Many regions of high quality renewable resources are remote and relatively undeveloped in terms of nearby transmission capacity. While the cost for additional transmission capacity used in this study is believed to be realistic, we explore the possibility that building new transmission capacity in the future may be difficult. In the *Expensive Transmission Scenario*, new transmission capacity is assumed to be three times as expensive as in the *Base Scenario*, an increase from $1,130 to $3,390 per MW of thermal capacity per km. This cost increase could come from many factors, examples of which are: delays in siting and permitting, compensation of landowners along transmission paths, and advanced transmission technologies that can help to balance variable renewable generation.

3.7.2 LIMITED HYDRO

One of the implications of global climate change may be reduced snowmelt from mountainous regions, resulting in decreased stream runoff and decreased energy production from hydroelectric facilities. We model the possibility of reduced hydroelectric energy in the *Limited Hydro Scenario* by reducing the average capacity factor of each dam in WECC on a linear schedule from historical averages in the present-day to 50 % below the historical average in 2050. This method does not include the regional or seasonal variability in runoff that may result from climate change. Consequently the *Limited Hydro Scenario* should be taken as a high-level exploratory scenario that investigates the importance of hydroelectric energy production to the WECC power system.

3.7.3 SMALL BALANCING AREAS

Committing and dispatching sub-hourly operating reserves over large geographic areas can reduce the cost of adding variable renewable generation to the power system (Hunsaker,

Samaan, Milligan, Guo, Liu, & Toolson, 2013). Consequently, increased coordination between the 37 balancing areas in WECC is likely as the amount of variable renewable generation increases over time. Deployment of the Energy Imbalance Market between the California Independent System Operator and PacifiCorp represents a step in this direction. This study investigates the evolution of the power system on a timescale that is likely to be longer than the evolution of increased coordination in sub-hourly reserve balancing. We therefore assume by default that sub-hourly reserves (spinning and quickstart) are balanced at the sub-regional level rather than the current 37 WECC balancing areas. In all scenarios except for the *Small Balancing Area Scenario*, six sub-regional balancing authorities are modeled: California, Pacific Northwest, Rocky Mountains, Desert Southwest, Baja California Norte, and Canada-WECC.

As the coordination and consolidation of balancing authorities is still in progress, we explore the possibility that sub-hourly reserves continue to be committed on the local balancing area level in the *Small Balancing Area Scenario*. In this scenario each load area is required to commit spinning and quickstart reserves, each at the level of 3 % of demand plus 5 % of variable renewable generation output within that load area. The 50 SWITCH load areas do not map exactly onto the 37 WECC balancing areas, but in most cases have similar geographic extent to the current WECC balancing areas.

3.8 PRICE AND COST SENSITIVITIES

3.8.1 LOW NATURAL GAS PRICE

The *Low Natural Gas Price Scenario* explores the possibility that natural gas prices may remain at relatively low levels through 2050. We use the United States Energy Information Agency's 2012 Annual Energy Outlook (AEO) High Technical Recoverable Resources scenario (EIA, 2012) as the basis of low natural gas price projections. The 2012 AEO projects regional price and consumption out to 2035, so a linear extrapolation is performed to project out to 2050. The base wellhead gas price is compared in Table 3-4 between the *Base Scenario* and the *Low Natural Gas Price Scenario*. The base wellhead price is regionally adjusted and also modified up or down by elasticity within SWITCH – the input wellhead price into SWITCH is shown for simplicity.

Table 3-4: Wellhead natural gas prices in the Base Scenario and Low Natural Gas Price Scenario by investment period.

Base Wellhead Natural Gas Price ($2013/MMBtu)	2020	2030	2040	2050
Base Scenario (default gas prices)	5.0	6.7	8.5	10.2
Low Gas Price Scenario	3.3	4.1	5.0	5.8

A scenario with high natural gas prices is not explored because the AEO 2012 does not contain a scenario that results in a large difference relative to reference scenario natural gas prices when extrapolated out to 2050. The omission of a high gas price scenario is not likely to be of substantial importance in the 2050 time frame as the fuel cost of natural gas is a minor driver of

grid operations due to the stringent cap on carbon emissions. A high natural gas price would create a disincentive to natural gas CCS technology, and in the limit that no CCS is built, the high gas price case would look like the *No CCS Scenario* in 2050. However, in the 2020 to 2040 time frame, the dependence on natural gas seen in most scenarios might be reduced in a high gas price scenario.

3.8.2 SUNSHOT SOLAR COSTS

Table 3-5: Comparison of solar technology overnight capital costs between default cost values found in the Base Scenario and costs found in the Sunshot Solar Scenario

Solar Technology	Year	*Base Scenario* Capital Cost $2013/$W_p$ (default costs)	*Sunshot Solar Scenario* Capital Cost $2013/$W_p$
Central Station PV	2020	2.64	1.07
Central Station PV	2030	2.43	1.07
Central Station PV	2040	2.27	1.07
Central Station PV	2050	2.13	1.07
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
Solar Thermal Trough Without Thermal Storage	2020	4.77	2.69
Solar Thermal Trough Without Thermal Storage	2030	4.38	2.69
Solar Thermal Trough Without Thermal Storage	2040	3.99	2.69
Solar Thermal Trough Without Thermal Storage	2050	3.60	2.69
Solar Thermal Trough With Six Hours Thermal Storage	2020	6.86	3.29
Solar Thermal Trough With Six Hours Thermal Storage	2030	5.58	3.29
Solar Thermal Trough With Six Hours Thermal Storage	2040	4.94	3.29
Solar Thermal Trough With Six Hours Thermal Storage	2050	4.94	3.29

Operations and maintenance costs are lower in the Sunshot Solar Scenario, but are not shown here because they constitute a small fraction of the total cost of solar energy. Overnight costs of other technologies can be found in Appendix A.10.1.

The installed cost of solar photovoltaics (PV) has undergone a drastic decrease in recent years. The *Sunshot Solar Scenario* explores the possibility that this trend continues into the future, with central station PV reaching an installed capital cost of ~$1/$W_p$ by 2020 (Table 3-5). Commensurate reductions in distributed photovoltaics are also assumed in this scenario. Moderate reductions in the cost of solar thermal relative to the *Base Scenario* are assumed, as the deployment trajectory of solar thermal is likely to be correlated with that of PV. This

scenario builds on the work of the SunShot Vision Study (DOE, 2012) and (Mileva, Nelson, Johnston, & Kammen, 2013).

3.9 NEW NUCLEAR OUTSIDE CALIFORNIA

The *New Nuclear Scenario* explores the possibility that new nuclear capacity could be built in WECC but outside of California in order to meet increasingly stringent carbon emission requirements. New nuclear generation capacity inside California is currently prohibited and no change to current policy is explored in this study. It may be politically difficult for California to import electricity from new nuclear power facilities given the in-state ban on new facilities, but in the *New Nuclear Scenario* we assume that electricity from new nuclear facilities could be imported into California. The *New Nuclear Scenario* should be viewed as an economic test for the viability of nuclear power to reduce carbon emissions from electricity generation. Nuclear power is frequently criticized for having high cost relative to other sources of generation, but often such comparisons do not include a number of improvements to the power system that must be made to integrate high fractions of wind and solar power. The purpose of the *New Nuclear Scenario* is therefore to compare on a level playing field the cost of decarbonization via nuclear power relative to renewable and/or CCS options.

3.10 INTERMEDIATE CALIFORNIA POLICY TARGETS

Two scenarios investigate the implications of increasing California-specific renewable energy policy targets in the 2020-2030 time frame while still reaching 2050 carbon emission targets.

3.10.1 CALIFORNIA DISTRIBUTED GENERATION MANDATE

California Governor Jerry Brown has set a goal of reaching 12,000 MW of distributed generation within the state of California by the year 2020 (Wiedman, Schroeder, & Beach, 2012). SWITCH does not enforce this goal by default and it is therefore not included in the *Base Scenario*. However, in the *12 GW Distributed PV Scenario* we do force SWITCH to install 12,000 MW of distributed solar photovoltaic capacity in California by 2020.

It should be noted that SWITCH does include a constraint in all scenarios that 3,000 MW of distributed solar photovoltaic capacity must be installed by 2016 in California. This constraint represents a number of programs collectively known as the “Go Solar California” programs (The California Solar Initiative, New Solar Homes Partnership, and various other programs). As these programs are well underway and are likely to reach their targets, we include them by default.

3.10.2 CALIFORNIA 50% RENEWABLE PORTFOLIO STANDARD

State-based Renewable Portfolio Standard (RPS) targets require that qualifying renewable generators produce a fraction of electricity consumed within a Load Serving Entity (LSE). Targets follow a yearly schedule, increasing over time to the final year specified (DSIRE, 2011). In subsequent years, the RPS target then remains flat at the level of the final year. California has an RPS target of 33 % by 2020. Post-2020, the 33 % target is enforced indefinitely.

In the version of SWITCH used in this study, all legally binding RPS targets are enforced throughout WECC (state-based goals are not included). Renewable power in SWITCH is defined as power from geothermal, biomass solid, biomass liquid, biogas, solar, and wind power plants. This is consistent with most of the state-specific definitions of qualifying resources in the western United States. In most states, large hydroelectric power plants (> 50 MW) are not considered renewable power plants due to their high environmental impacts. Small hydroelectric power plants (< 50 MW) do not qualify as renewable power in the current version of the model.

California is currently considering increasing the RPS target through 2030. In the *California 50 % RPS Scenario*, we extend the California RPS target to 50 % in 2030. The target is then held constant at 50 % post-2030.

3.11 CARBON-NEGATIVE ELECTRICITY WITH BIOMASS CCS

Under an economy-wide carbon cap, the underground sequestration of carbon from solid biomass sources could enable other sectors of the economy to reduce emissions at a slower rate than would be necessary for an electricity system with net positive carbon emissions. Pursuing this strategy could become important if decarbonization in other sectors is especially difficult.

The *-20% Carbon Cap / BioCCS Scenario* and the *-40% Carbon Cap / BioCCS Scenario* explore the possibility that if solid biomass is made available to the electric power system, it might be economical to generate electricity using solid biomass and sequester the resultant carbon underground. In this scenario we give SWITCH the option to build biomass integrated combined cycle generators equipped with carbon capture and sequestration (BioCCS for short). We also cap electricity sector emissions at below zero percent of 1990 levels by 2050, thereby forcing the electricity system to become net carbon negative. The only net carbon negative infrastructure modeled in this study is BioCCS, so a negative carbon cap forces the installation of BioCCS. The availability of biomass is input into SWITCH in the form of a supply curve for each load area (Section A.8: Biomass Solid Supply Curve).

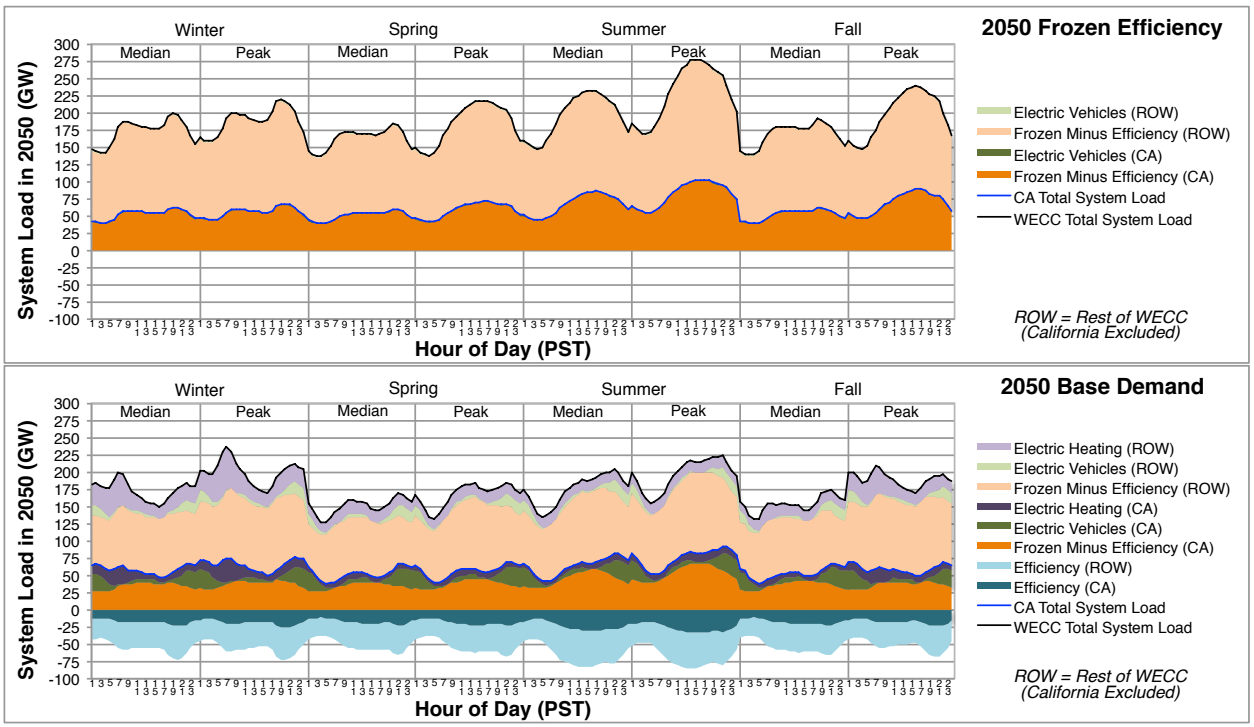
3.12 BUSINESS-AS-USUAL SCENARIO

The *Business-As-Usual Scenario* represents a reference scenario to which costs of carbon policy implementation can be compared. It does not represent a projection of the development of the WECC power system and should not be taken as such. In this scenario, a WECC-wide cap on carbon emissions is held constant at 100 % of 1990 levels from 2020 onwards. The demand profile is taken to be a frozen efficiency demand profile in which aggressive efficiency measures are not deployed. The non-electrification demand that must be served is therefore larger than that found in any other demand profile explored in this study (even larger than the reduced efficiency implementation demand profile). However, little electrification of heating or transportation is assumed, so the magnitude of demand in the frozen efficiency demand profile in 2050 is roughly equal to that found in the base demand profile. The *Business-As-Usual Scenario* has 8 % more demand across WECC in 2050 than the *Base Scenario*. The base demand

profile and the frozen efficiency demand profile differ drastically in shape, as the base demand profile has a strong winter nighttime peak in addition to the strong late afternoon summer peak found in both profiles.

The *Business-As-Usual Scenario* is given the option to install new biomass generators because the impetus to use all biomass in the transportation sector is not nearly as strong if little economy-wide decarbonization is occurring. In addition, we give the *Business-As-Usual Scenario* the option to build new nuclear capacity.

Figure 3-6: Demand profile in 2050 for the Business-As-Usual Scenario



The demand profile used in the Business-As-Usual Scenario is also referred to as the 'Frozen Efficiency' demand profile. The Base Scenario demand profile is included for comparison.

4 POWER SYSTEM PLANNING OPTIMIZATION RESULTS

4.1 ENERGY GENERATION

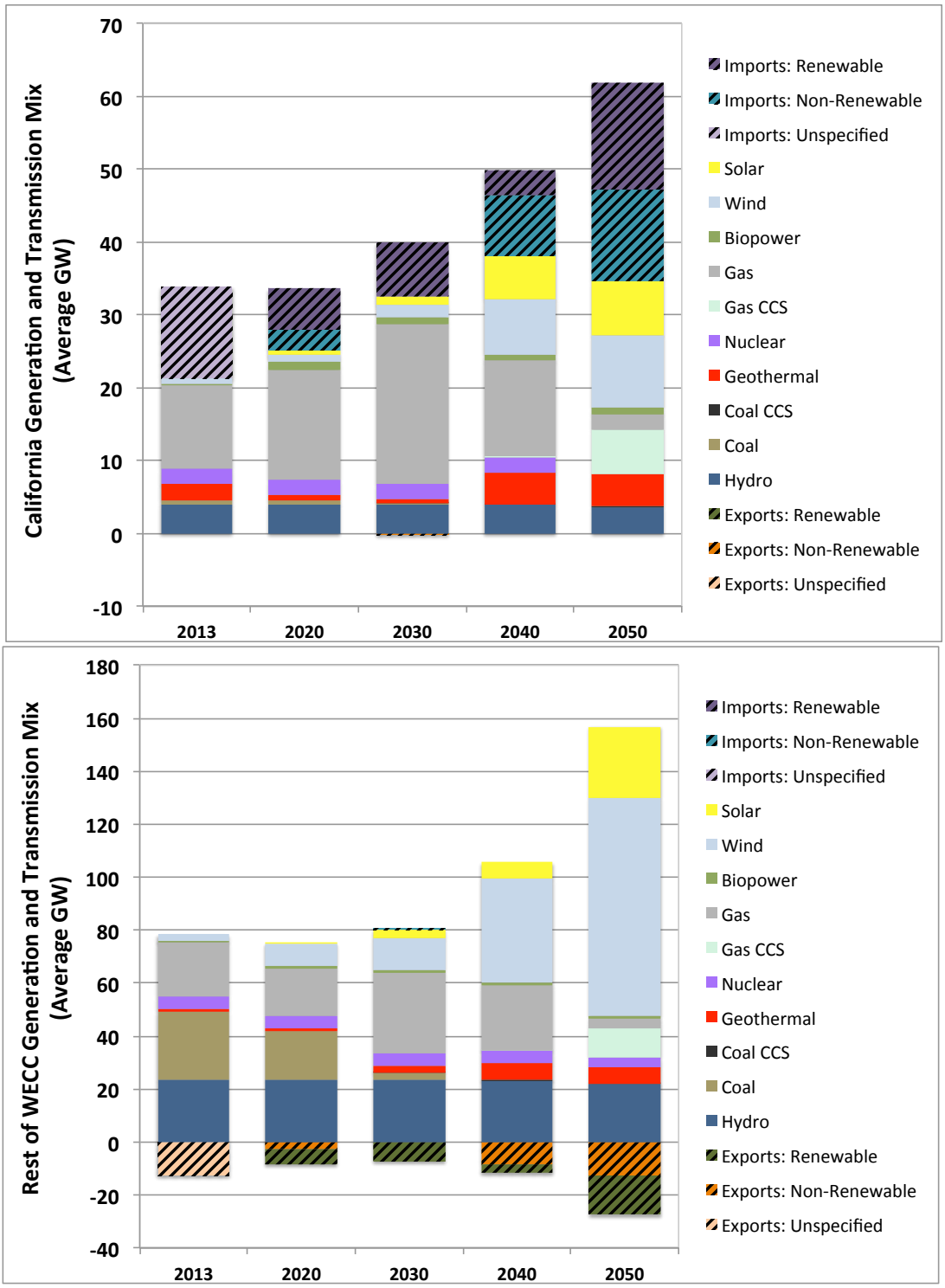
4.1.1 BASE SCENARIO

The *Base Scenario* is used as a point of comparison throughout this chapter and is therefore described more thoroughly than the exploratory scenarios.

The *Base Scenario* includes the implementation of drastic efficiency measures based on existing available technology. Many of these efficiency measures are deployed between present day and 2020, thereby reducing the total magnitude of demand slightly, even during a period of moderate population growth. Consequently, demand is relatively flat in the 2020 time frame and little change is seen between the generation mix of present day and 2020 power systems, with the exception of growth in renewable generation from renewable portfolio standards. As the cap on carbon emissions is enforced across all of WECC in this study, coal retirements outside of California aid in the meeting of 2020 carbon targets (100% of 1990 levels). The amount of electricity generated from natural gas is not reduced during this time frame in the *Base Scenario* due largely to coal retirements.

In the 2030 time frame, natural gas and renewable generators have replaced virtually all coal generation as existing coal plants are retired by SWITCH after 40 years of operation. Post-2030 carbon emission targets preclude the construction of coal without CCS. The retirement of coal alongside continued efficiency deployment in the 2030 time frame makes transmission capacity into California available. While some renewables are installed within the footprint of California, the deployment of renewable power plants to California's 33 % RPS target is done largely out of state due to a combination of lower installed cost and higher resource quality. In the version of SWITCH used for this study, RPS targets can only be met by renewable energy that is either generated inside or delivered to the state for which the target is binding (tradable RECs are not modeled). Consequently, transmission capacity is reserved almost exclusively for renewable imports into California in the 2030 time frame. If the current trend of in-state renewable energy deployment in California continues, the magnitude of RPS-eligible imports into California shown here may not be realized. However, it should be noted that California could economically meet much of its RPS target using out of state power. Discussion should continue about the value of in-state renewable deployment as in many cases out-of-state renewable power might be less expensive.

Figure 4-1: Base Scenario average hourly generation and transmission mix as a function of investment period and fuel, in California and the rest of WECC

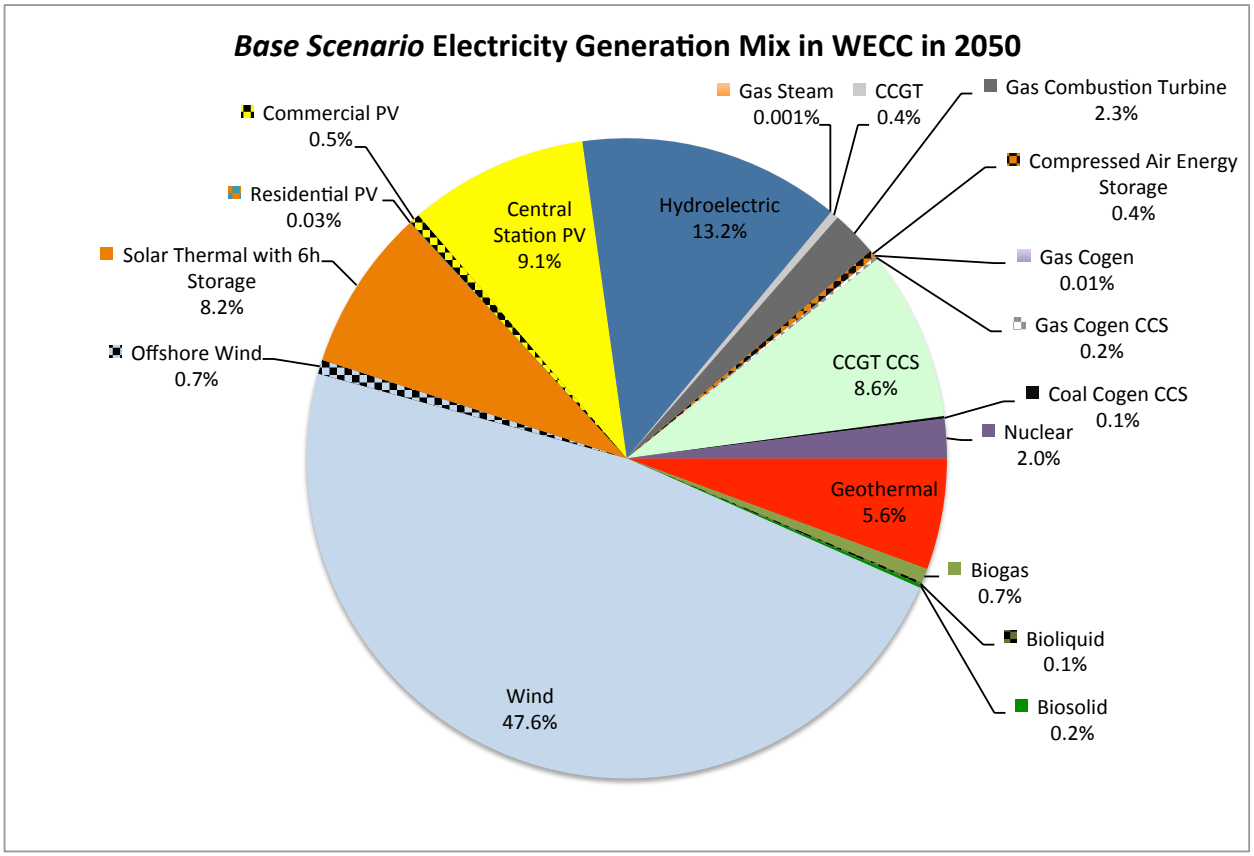


To convert into yearly energy totals in GWh per year, multiply the average GW by 8760 hours per year. We do not track renewable energy certificates in 2013 and therefore transmission in this time frame is 'Unspecified'. Transmission is specified in net (as opposed to gross) terms.

Existing hydroelectric facilities located in the Pacific Northwest currently send power to California, but are less available to California by 2030. This is evident in Figure 4-1 as imports into California approach zero from the 'non-renewable' category, of which large hydro is a part. Instead of hydroelectric power, wind power from the Pacific Northwest dominates north-south transmission flow into California in the 2030 time frame.

Between 2030 and 2050, natural gas without CCS is phased out in order to meet an increasingly stringent carbon cap. A moderate amount of gas CCS appears in the WECC power mix after 2040, comprising 8.6 % of electricity generated across WECC in 2050 (Figure 4-2). Gas combustion turbines, which can ramp output up and down quickly, are used occasionally in times of peak net demand (demand minus variable renewable generation), and are the dominant source of carbon emissions in the 2050 time frame.

Figure 4-2: Base Scenario technology mix across WECC in 2050 as a percentage of total electricity generated



The fleet of combined cycle gas turbines (CCGTs) deployed in the 2020-2030 time frame is mothballed for large parts of the year in the 2050 time frame (Figure 4-2) due to the cap on carbon emissions. CCGTs without CCS provide only 0.4 % of energy across WECC in 2050, with an average capacity factor of 9 %. In the framework of the SWITCH model, we do not consider these CCGT investments 'stranded,' as the model has foresight out to the point at which their capacity factors are drastically reduced, and would therefore not choose to install them if the

decrease in capacity factor in late plant life was a crucial economic factor in their installation. In other words, SWITCH finds the installation of these CCGTs to be the economical solution for meeting demand in the 2020-2040 time frame even given that CCGT utilization must decrease by 2050. We do not investigate CCGT investments that would be made without foresight regarding this capacity factor decrease, but it is very likely that more investment in CCGT capacity in the 2020-2040 time frame would be made without such foresight. The risk of political difficulties created by deploying and then quickly retiring a new fleet of CCGTs may justify a different strategy in the 2020-2040 time frame. This strategy is the subject of ongoing investigation, but is not discussed further in this study.

In the 2030-2050 time frame, solar and wind are deployed quickly and at scale to replace gas generation. By 2050 solar and wind comprise 18 % and 49 % of electricity generated respectively. Geothermal also increases in this time frame, reaching 6 % of electricity generated in 2050. We do not explore enhanced geothermal technologies in this study due to a lack of technological maturity, but were enhanced geothermal to become a viable option in the future, the fraction of electricity generated from geothermal could rise.

The deployment of solar electricity is dominated by photovoltaic technologies between present day and 2040, but in the 2050 time frame there is a large build-out of solar thermal with thermal energy storage. Despite higher capital costs than central station photovoltaics in the 2050 time frame, solar thermal with thermal energy storage comprises 46 % of total solar electricity generated in 2050 (8 % of total electricity – see Figure 4-2) in large part due to the ability to produce electricity after the sun has gone down. With large amounts of nighttime demand from electric vehicles and electric heating in 2050, the value of nighttime power is high and thus solar thermal is deployed at scale. Nighttime electricity demand is increasing year-on-year in this study, so it is only after 2040 that solar thermal with thermal energy storage is deployed at multi-GW scale. We do not see solar thermal without thermal energy storage deployed at any time between present-day and 2050 in the *Base Scenario* due to unfavorable costs and similar production profiles relative to central station photovoltaics.

4.1.2 EXPLORATORY SCENARIOS

4.1.2.1 2030 TIME FRAME

In the 2030 time frame, transmission into California is dominated by renewable power in the form of bundled renewable energy certificates (Figure 4-3, top). Net imports into California comprise between 17 and 24 % of California's electricity mix in this time frame. The *California 50 % RPS Scenario* increases the magnitude of renewable energy imports into California in 2030 to the highest level of all scenarios investigated. A 50% California RPS is found to incentivize the construction of additional geothermal and wind power in California relative to the *Base Scenario*, and also reduces the fraction of natural gas in the energy mix. This reduction of natural gas generation inside California leaves room in the carbon cap (which is enforced over all of WECC in the same magnitude in both the *Base Scenario* and the *California 50 % RPS Scenario*) for more coal generation to persist outside of California in 2030. This result must be interpreted in the context of the WECC-wide carbon cap investigated in this study, as a carbon

cap that covers only California would not show this amount of linkage between in-state and out-of-state carbon emissions.

Natural gas is shown to play a central role in the energy mix in 2030 in all scenarios investigated, providing between 41 % and 53 % of energy across WECC. A low gas price aids in the removal of coal generation from the WECC power system, but does not drastically increase the deployment of natural gas generation as the cap on carbon emissions is binding in this time frame.

Coal plays a minor role in the WECC power system in 2030, even in the *Business-As-Usual Scenario*, in which WECC-wide emissions are capped post-2020 at 100 % of 1990 levels. The favorable economics of natural gas relative to coal and the presence of high-quality renewable resources within WECC explain much of the removal of coal from the energy system.

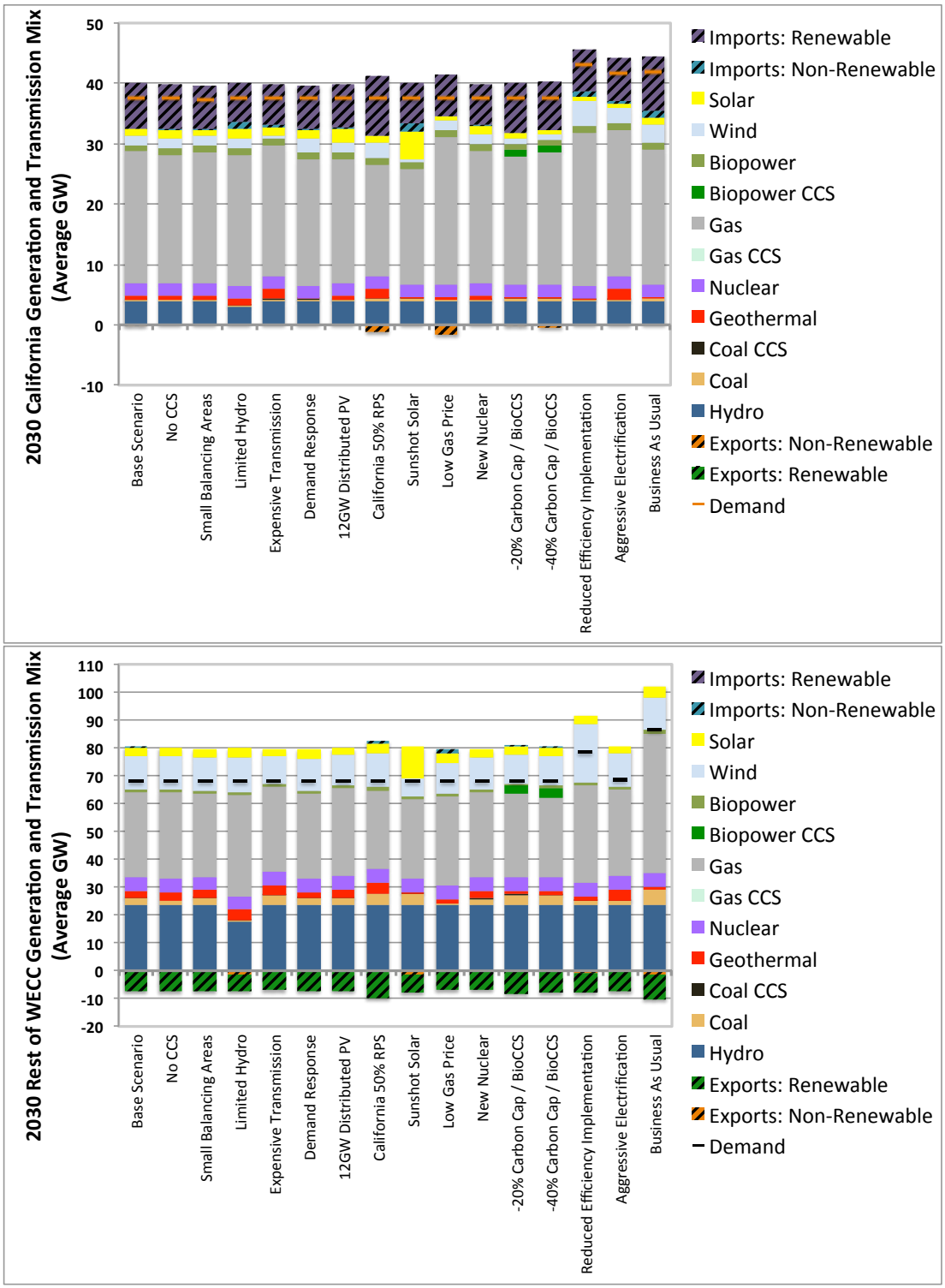
In the *Sunshot Solar Scenario*, $\$1/W_p$ central station photovoltaic capital costs are attained in 2020; smaller reductions are assumed for solar thermal. In this scenario, in which solar costs are decreased relative to the *Base Scenario*, solar deployment displaces wind and geothermal power. This demonstrates that under a cap on carbon emissions, low cost solar power may not further serve to reduce emissions of the power system. Solar is still less cost-effective than gas generation in this time frame due to relatively inexpensive natural gas fuel costs and does not therefore decrease the amount of electricity generated from gas. However, it should be noted that the presence of low-cost solar power might make it easier to enact laws that more quickly tighten the cap on carbon emissions, as the costs imposed by such a cap would be reduced with inexpensive solar power.

Even if nuclear power is available to be constructed outside of California, as is the case in the *New Nuclear Scenario*, it is shown to not be economical in the 2030 time frame as this scenario does not add new nuclear capacity by 2030. This result must be interpreted in the context of the magnitude of energy efficiency investigated in this study – we did not run a scenario with reduced efficiency implementation and new nuclear builds allowed, so it is unknown whether new nuclear would be economical if there was additional demand to be met.

The amount of geothermal development in the 2030 time frame is highly uncertain between the scenarios. This highlights that geothermal may be competitive in this time frame with other renewable or low-carbon technologies, and that depending on future cost and power system infrastructure deployment strategies, geothermal could contribute substantially towards meeting carbon emission goals in a cost-effective manner.

In scenarios with an aggressive carbon cap that reduces emissions below zero by 2050 (Figure 3-1), some biomass carbon sequestration is already installed by 2030. Biomass CCS is the only CCS technology installed by 2030 in any scenario found in this study. This result suggests that near-term CCS development may want to focus on the sequestration of biomass rather than that of fossil fuels. This is especially true if decarbonizing other sectors of the economy will be very difficult, as biomass CCS can act as a hedge against this difficulty.

Figure 4-3: Average hourly generation, transmission, and electricity demand in 2030 for all scenarios, divided into California and rest of WECC.



To convert into yearly energy totals in GWh per year, multiply the average GW by 8760 hours per year. Data can be found in Table D-1 and Table D-2.

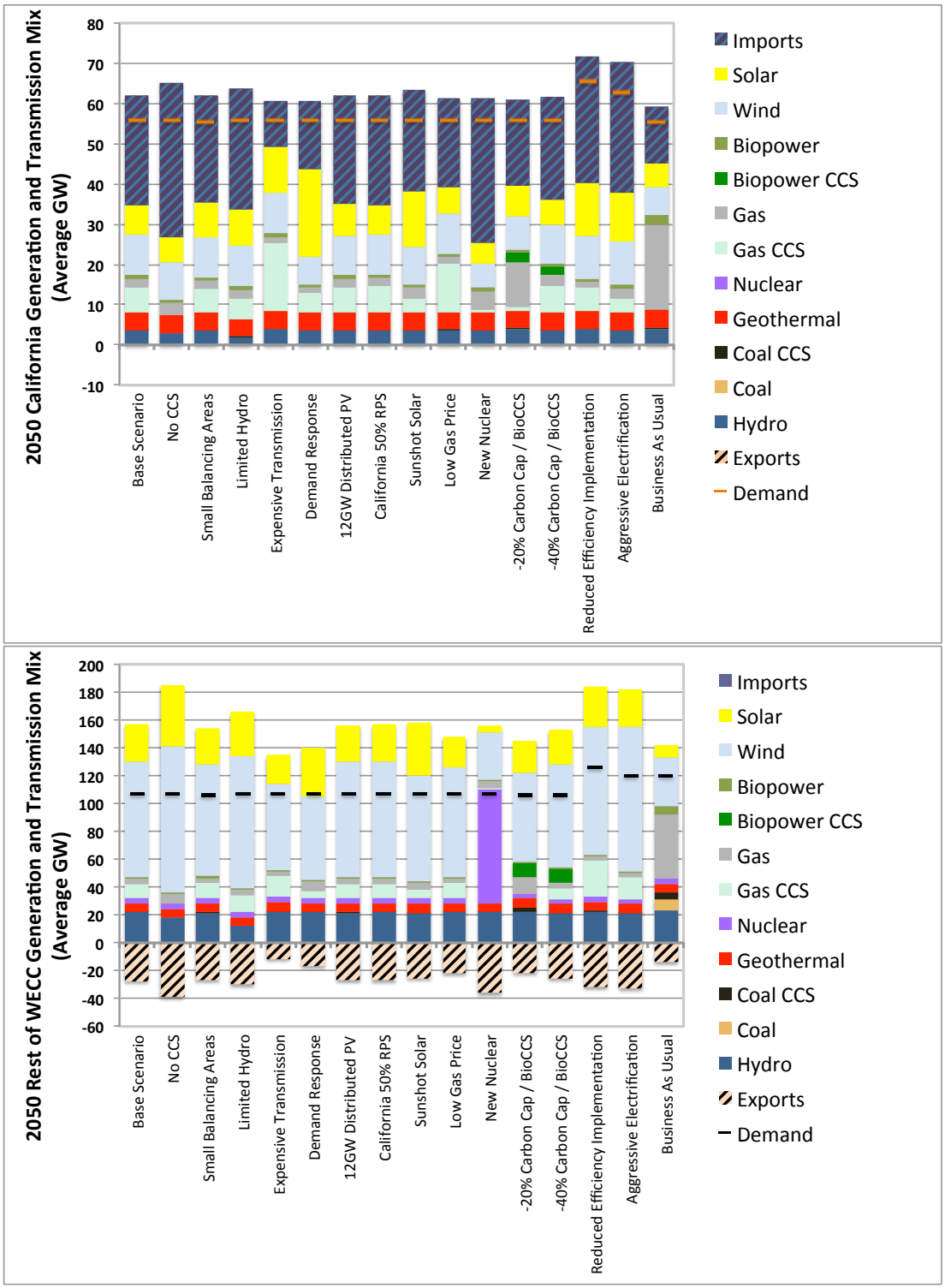
4.1.2.2 2050 TIME FRAME

By 2050, we find that there are many possible configurations of the power system that could reduce carbon emissions from electricity to 86% *or more* below 1990 levels. In general, a mix of wind, solar, geothermal, and natural gas with CCS generation sources are deployed to make a low carbon power system. Existing hydroelectric facilities are kept operational indefinitely and thereby also provide zero-carbon power. All geothermal energy available is developed in all scenarios, implying that if more viable projects are discovered than exist in the current SWITCH database of potential geothermal projects, it is likely that these additional geothermal projects would also be built.

Power from variable renewable sources comprises a large fraction of the WECC-wide generation mix, with wind contributing between 22 and 55% of electricity generated, and solar contributing between 7 and 31 % across scenarios. The positive correlation of wind power output to nighttime electricity demand from electric vehicles and heating helps to explain why more wind power relative to solar power is generally deployed across WECC (Section 4.4: Hourly Dispatch). The *Business-As-Usual Scenario* generates 22 % and 8 % of electricity from wind and solar respectively, highlighting that variable renewable sources can economically compete with conventional generation even without deep reductions in carbon emissions. The *No CCS Scenario* generates the largest fraction of power from wind and solar, comprising 79 % of total electricity generated. The *New Nuclear Scenario* generates the smallest fraction of power from wind and solar, comprising only 27 % of total electricity. All other scenarios that drastically reduce carbon emissions generate greater than 55 % of energy from variable renewables in the 2050 time frame. This percentage suggests that if decarbonization of the power system is to take place, understanding the operational difficulties associated with high fractions of energy from variable sources will become increasingly important. In addition, planning such a power system will likely require large amounts of regional coordination and detailed modeling platforms to aid in cost-effective power system deployment.

A small fraction of variable renewable energy available to the power system is not used (is curtailed) due to the lack of demand, transmission capacity, storage capacity, etc. to deliver energy to demand centers at times when it is needed. This represents an economic trade-off between building additional storage and transmission facilities or slightly over-sizing renewable power facilities such that there is ample energy from these facilities in hours of great need. Curtailing some variable renewable power becomes the lowest-cost strategy under an aggressive carbon cap, but in general power is curtailed *outside* of California. In the future, it will be important to determine how variable renewable generators are compensated for reducing power output from their maximum possible output.

Figure 4-4: Average hourly generation, transmission, and electricity demand in 2050 for all scenarios, divided into California and rest of WECC



To convert into yearly energy totals in GWh per year, multiply the average GW by 8760 hours per year. Data can be found in Table D-3 and Table D-4.

The availability of demand response in the *Demand Response Scenario* incentivizes solar generation relative to the *Base Scenario*, implying that solar is an abundant and relatively low-cost zero-carbon resource in 2050. The availability of demand response reduces the amount of gas CCS from the generation mix because as the penetration of solar is increased, more room for non-CCS gas is available within the cap on carbon emissions. Similar behavior is found in the *Sunshot Solar Scenario*, in which solar capital costs are lower than are found in the *Base Scenario*. This implies that the marginal value of solar power in the daytime in the *Base Scenario* is very low by 2050 and therefore the availability of flexibility to move demand to hours of peak solar production is more valuable relative to the existence of inexpensive solar power.

Most natural gas generation is removed from the power system by 2050 due to the cap on emissions. The remaining gas generation is almost completely CCS. The *Low Gas Price Scenario* substantially increases the amount of gas CCS in California relative to the *Base Scenario*, but the same behavior is not seen outside California. This highlights the difficulty of powering California with renewable energy relative to surrounding states on the basis of resource cost and quality. The large build-out of gas CCS capacity in California in the *Expensive Transmission Scenario* further corroborates this difficulty.

California is found to be a net power importer in all scenarios, with the *Expensive Transmission Scenario* importing the least power (19 %) and the *No CCS Scenario* importing the most power (60 %). It is clear that economic incentives exist to import large amounts power into California, but these considerations must be balanced with California's desire to create in-state jobs and power system operational constraints that may limit the total imports into California.

No coal generation without CCS remains in the power mix in 2050. A small amount of coal CCS is occasionally installed, always outside of California. These results suggest that coal CCS is not an important technology to pursue if the goal is to drastically decarbonize the energy system over the course of the next 37 years. The current state of CCS technology does not allow for complete emissions capture at reasonable cost, and even the non-captured emissions (~15 - 20 %) from coal CCS become too large in magnitude to fit within a power sector carbon cap that reduces emissions by 86 % relative to 1990 levels by 2050. These results are counter to the widespread opinion that coal CCS has a large role to play in a low-carbon energy system. Our results imply the opposite – construction of coal CCS generators would lock-in emissions (the non-captured emissions) that would be uneconomical to purge from the power system by 2050. If non-captured emissions from coal CCS could be reduced to near zero at reasonable cost, or if coal CCS generation technology were to become much less expensive than is assumed in this study, then coal CCS may be able to contribute to long-term deep carbon emission reduction targets.

In the *New Nuclear Scenario*, in which new nuclear generation is allowed to be built outside California, large-scale deployment of nuclear power takes place. In this scenario, imports into California comprise almost 60 % of California's electricity mix, almost all of which is nuclear power from out-of-state.

Given the assumed cost and availability of biomass in the 2050 time frame, Biomass CCS technology would enable the power system to become carbon-negative, possibly reducing WECC-wide carbon emissions from the electricity sector to -40 % of 1990 levels by 2050. Biomass CCS could generate roughly 7 % of WECC-wide electricity in this time frame. The assumed cost of Biomass CCS technology makes it such that even if the WECC power system is capped at -20 % of 1990 emissions (instead of -40 %), the same fraction of total WECC-wide electricity is generated from Biomass CCS in either case. In the *-20% Carbon Cap/BioCCS Scenario* there is room in the carbon cap for non-CCS gas generation due the net negative carbon emissions of Biomass CCS, whereas in the *-40% Carbon Cap/BioCCS Scenario*, little room exists for non-CCS gas because the amount of available biomass limits net-negative carbon emissions.

4.2 GENERATION, STORAGE, AND TRANSMISSION IMPORT/EXPORT CAPACITY

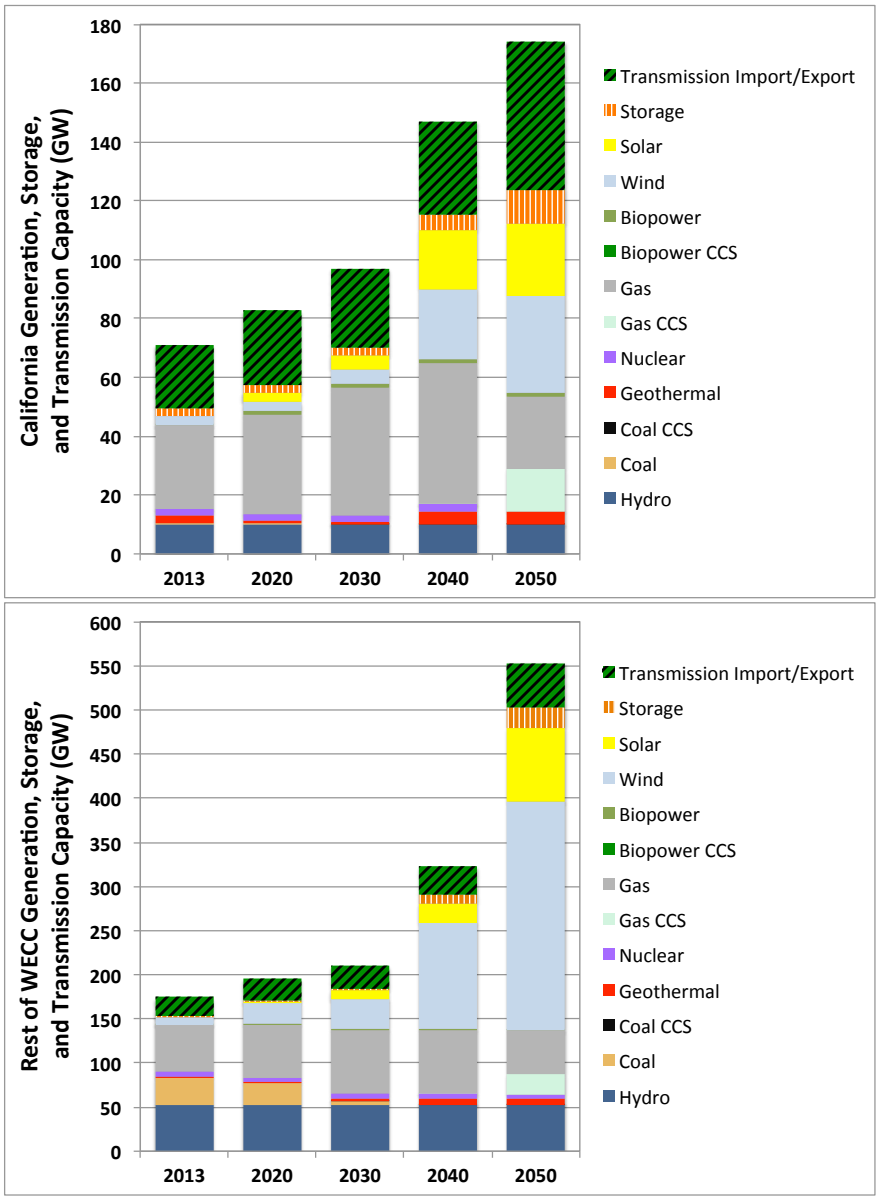
4.2.1 BASE SCENARIO

In the *Base Scenario*, California experiences a moderate expansion of natural gas capacity between present-day and 2040, followed by a contraction by 2050. In the 2050 time frame, 14 GW of gas-fired generation with CCS is cited within California in order to provide low-carbon electricity at times when insufficient low-carbon power is available. Wind and solar power deployment in California increases over time and occurs with roughly equal fractions of wind and solar capacity. A stringent carbon cap in the 2040-2050 time frame induces a large increase in the deployment of wind, solar, and geothermal generation capacity, with 33, 25, and 5 GW deployed by 2050 respectively in California.

The ability of California to import and export power becomes increasingly important over time, with the total transmission transfer capacity across the California border reaching 50 GW in 2050. This transfer capacity represents more than double the present-day transfer capacity. The ability to temporally move energy via storage also becomes important in the 2050 time frame, with 8 GW of compressed air energy storage capacity and 1 GW of battery storage capacity installed in California. In addition, 2 GW of solar thermal with thermal storage is installed in California by 2050.

The evolution of capacity in the rest of WECC largely follows that of California. Present-day California lacks substantial coal generation and thus the retirement of coal-fired power by 2030 that is observed in the rest of WECC is not observed in California. In addition, the high quality wind resources found in the rest of WECC are deployed in large quantity, becoming more than 50 % of generation capacity in the rest of WECC by 2050 (250 GW of wind capacity). Note that the deployment of power systems infrastructure in the rest of WECC happens at a quicker pace relative to California as time draws closer to 2050.

Figure 4-5: Base Scenario generation, storage, and transmission capacity as a function of investment period, divided into California and rest of WECC



Compressed air energy storage (CAES) is a hybrid gas-storage technology but for simplicity all CAES capacity is included only in the 'Storage' category here. Solar thermal generators with thermal storage are included only in the 'Solar' category. The 'Transmission Import/Export' category represents the amount of transmission path transfer capacity between California and the rest of WECC (including Baja California Norte). 'Transmission Import/Export' is of equal magnitude on both plots. Path transfer capacity is defined as the path thermal transmission capacity de-rated by a thermal-to-path transmission derating factor (Appendix A.2.2). The present day (2013) transmission import/export capacity also includes a handful of transmission projects that are assumed to come online before 2016, and therefore may appear slightly larger than expected.

4.2.2 EXPLORATORY SCENARIOS

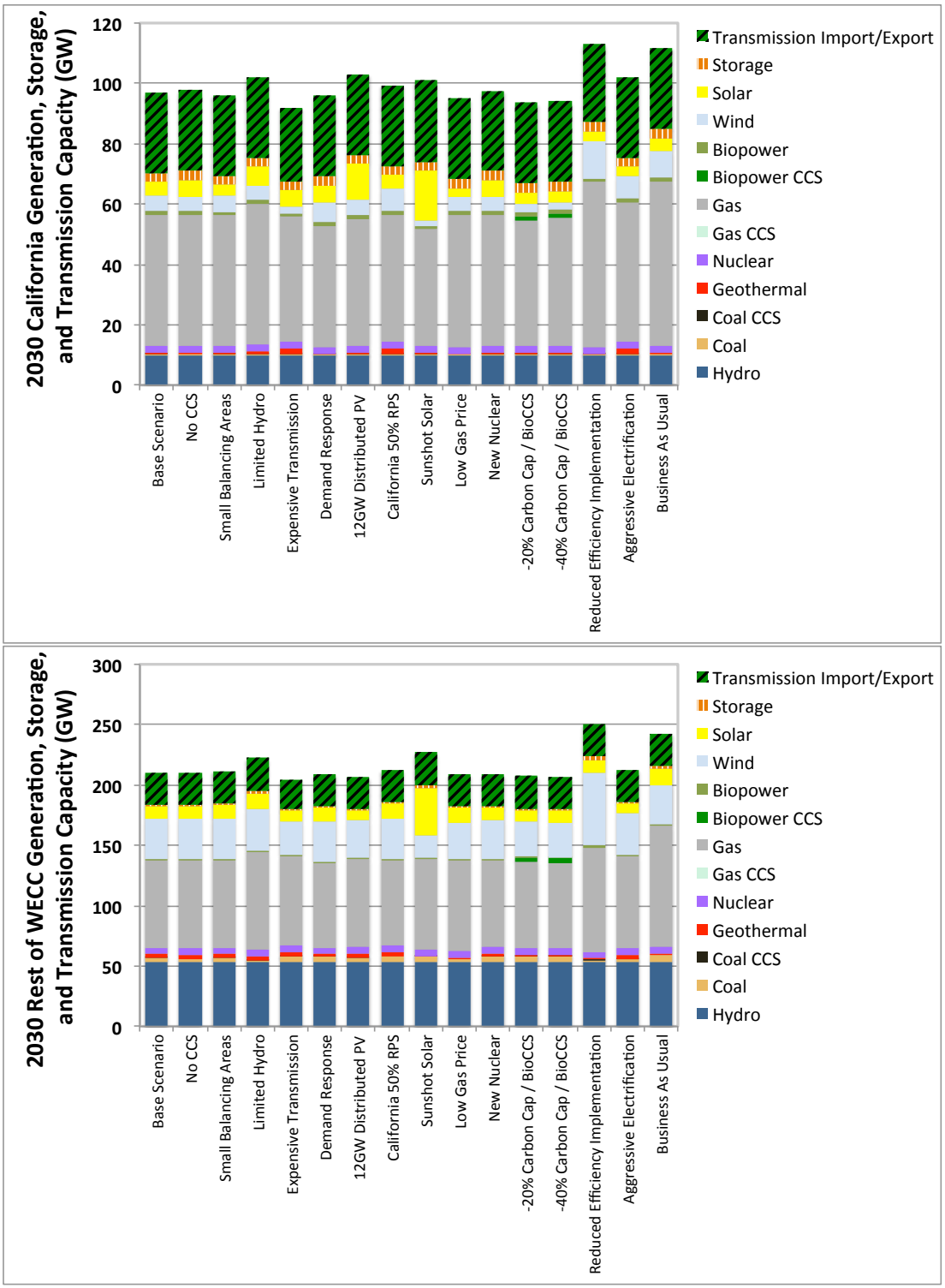
4.2.2.1 2030 TIME FRAME

In general, the scenarios explored in this study focus on the 2050 time frame, and consequently there is a relative lack of diversity in the 2030 findings. Gas capacity represents a large fraction of generation capacity across all scenarios in 2030, with roughly 40 % of total installed capacity across WECC from gas generation. California has a higher percentage of installed gas capacity relative to other generation capacity than is found in the rest of WECC. Solar and wind capacity are located both within California and in the rest of WECC in an effort to meet renewable portfolio standards and distributed generation targets.

An increase in the magnitude of California renewable portfolio standards by 2030 (*California 50 % RPS Scenario*) or distributed generation targets by 2020 (*12 GW Distributed PV Scenario*) can help to install more renewable capacity in California than is found in the *Base Scenario*. The *Expensive Transmission Scenario* is also effective at siting renewable capacity inside California rather than importing renewable power from adjacent states. California renewable policies are found to be effective at reducing the capacity factor of gas generation within the state, but less effective at reducing installed gas capacity.

Most new transmission and storage is built after 2030 to enable integration of increasing fractions of variable renewables. Build-out of transmission and storage capacity is found in some scenarios by 2030, but this build-out does not represent the dominant behavior of the scenarios investigated here. Despite the lack of deployment of new electricity transmission or storage capacity by 2030, there may need to be nearer-term development in order to be prepared for the fast post-2030 increase in capacity of these assets. The small magnitude of transmission and storage build-out is dependent on the extensive utilization of gas plants in the 2030 time frame. While we do not explicitly model gas pipelines in this study, the results infer that gas pipelines would be very active in this time period.

Figure 4-6: Generator and storage capacity installed throughout California and the rest of WECC in 2030 for all scenarios



Data can be found in Table D-5 and Table D-6.

4.2.2.2 2050 TIME FRAME

Between 2030 and 2050, natural gas generation capacity without CCS is removed from the power system and replaced by various combinations of low-carbon generation technologies due to the increasingly stringent cap on carbon emissions. If carbon capture and sequestration is available, gas CCS is built by 2050 across most scenarios in moderate quantity.

The fleet-wide average capacity factor of non-CCS gas generation drops steeply between 2030 and 2050, reaching only 5 % to 16 % in 2050 for scenarios that meet the 86 % emission reduction target, indicating that gas plants are only operated for a handful of hours each year but are of extremely high value during those few hours. This result suggests the difficulty of supporting gas generation through energy and ancillary service market revenues, and implies the need for other revenue streams such as a capacity market or long-term contracts.

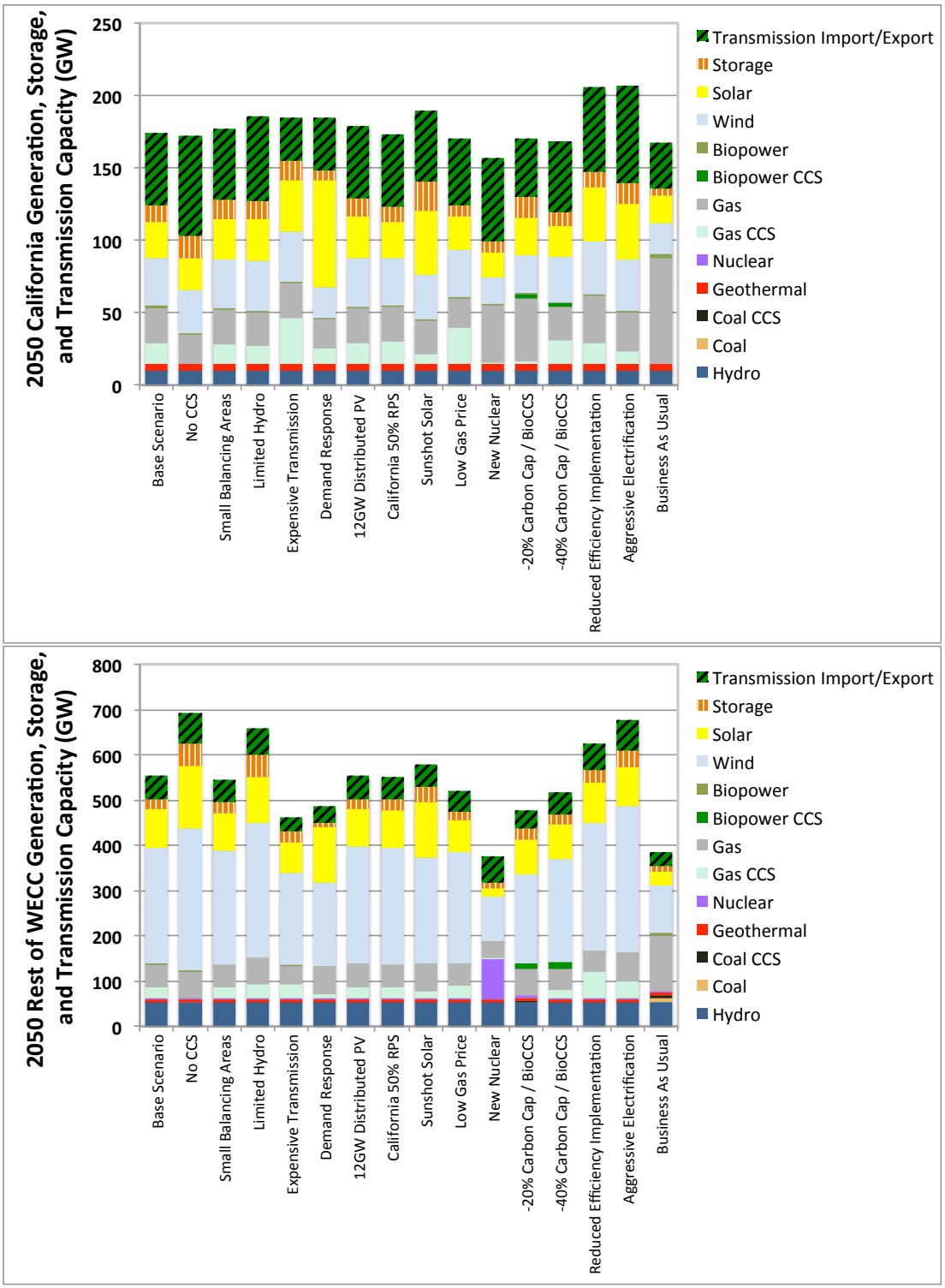
The installed capacity of wind power outside California by 2050 tends to be substantially larger than that of solar due to high capacity factor wind along the Rocky Mountains. Within California there tends to be relatively similar amounts of installed capacity of wind and solar power.

New storage is deployed at multi-GW scale by 2050 in all scenarios in which deep carbon emission reductions are enforced, with between 5 and 16 GW of capacity added in California and 8 to 49 GW added in the rest of WECC. Even in the *New Nuclear Scenario*, a scenario that is dominated by the installation of baseload nuclear power, 18 GW of new storage projects are built by 2050 as the flexibility of storage is used to help smooth peak demand. The *Business-As-Usual Scenario*, not included in the previous values, installs only 1 GW of new storage in California, but does add 12 GW in the rest of WECC. Across all scenarios, 44 % of all newly installed storage capacity is sodium sulfur battery technology, whereas 56 % of capacity is compressed air energy storage. We do not allow installation of new pumped hydro projects in the current version of SWITCH, though in some cases these storage projects may also be competitive.

In the *Sunshot Solar Scenario*, inexpensive solar power incentivizes construction of solar power projects in California. In an effort to absorb inexpensive solar power, much more new storage is added to the California electricity system than is found in the *Base Scenario*, comprising 16 GW of new capacity in the *Sunshot Solar Scenario*, (8 GW are deployed in the *Base Scenario*). Should central station photovoltaic costs fall to $\$1/W_p$ in the near-term, California should be prepared for many large-scale storage installations after 2030. However, if demand response is available in large amount by 2050 as is the case in the *Demand Response Scenario*, the need for storage may be reduced as demand response can serve many of the same functions as utility scale storage and does not suffer from the magnitude of round trip efficiency losses intrinsic to storage technologies.

Much new transmission capacity is installed after 2030 to bring remote, high-quality renewable energy to demand centers. Transmission build-out will be discussed further in Section 4.7: Transmission Capacity.

Figure 4-7: Generator and storage capacity installed throughout California and the rest of WECC in 2050 for all scenarios considered in this study



Data can be found in Table D-7 and Table D-8.

4.3 POWER SYSTEM COST

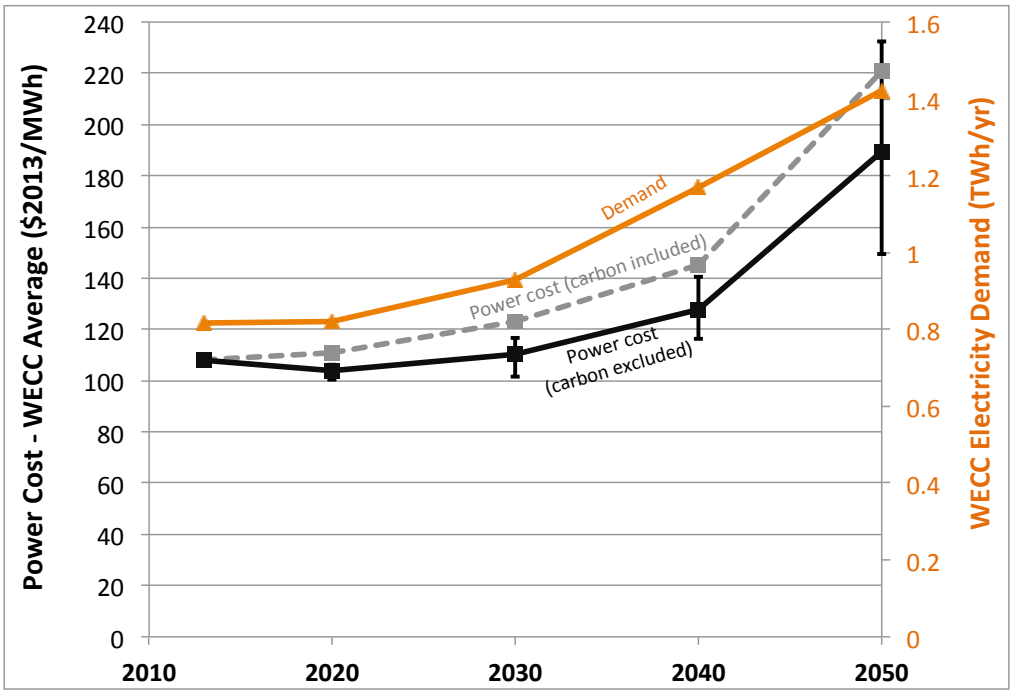
4.3.1 BASE SCENARIO

In acknowledgement that cost of electricity is an important factor in the economic welfare of society, we employ a cost-minimization framework, thereby meeting policy goals and projected electricity demand at the lowest possible cost. The cost of power reported in this study is limited to the electric power sector, so costs related to the installation of energy efficiency, vehicle electrification, heating electrification, etc., are not included here as they are traditionally tallied in other sectors. We include a treatment of natural gas price elasticity to reflect the dependence of economy-wide natural gas consumption on natural gas prices in the electricity sector.

The costs presented here should be interpreted in the context of modeling assumptions that are made in this study. In an effort to be conservative, we do not by default assume far-reaching cost or technological improvements in generation, transmission, or storage technologies. Should there be improvement in these technologies, the cost of power could decrease substantially relative to the *Base Scenario* power cost. However, if deployment of a low-carbon power system does not occur as smoothly as is envisioned here, then the calculated power cost could be liberal. The inherent uncertainty implicit in modeling the power system 37 years into the future is partially captured by the choice of many exploratory scenarios. The reader should be cautioned not to interpret the results presented here as confident indications of what will transpire in the future.

Carbon emission permits are collected from emitting sources in order to provide an incentive for these sources to reduce emissions, thereby incurring costs from investments that aid emission reductions. However, as revenue from carbon permits could be reinvested in the electricity sector, the cost of the carbon permits themselves may or may not reflect an additional cost incurred by the power system. If revenue from carbon permits were transferred out of the electricity sector, this would represent an influx of income to another sector of society. From a societal welfare perspective, this influx would counterbalance the additional cost in the electricity sector and therefore should not be counted as an additional cost to the electricity sector. Consequently, we choose to report and discuss the average cost of power without the cost of carbon permits included. For conceptual simplicity, one can therefore assume that carbon permit revenue from the electricity sector will go towards reducing the capital and fixed costs of operating the power system.

Figure 4-8: WECC average power cost and average electricity demand by investment period in the Base Scenario



The power cost with 'carbon included' differs from that with 'carbon excluded' by the cost of carbon permits. The error bars represent the range of costs found in scenarios other than the Base Scenario. We do not include a carbon price in the present-day in this study.

We find that in the *Base Scenario*, the average cost of power stays relatively flat compared to present-day power costs through 2040 (Figure 4-8). In the 2020 to 2030 time frame, reduced demand via energy efficiency measures and inexpensive natural gas are key drivers of the power cost. Between 2030 and 2040, electricity demand increases due in large part to vehicle and heating electrification. Both of these demand categories are modeled with a demand profile that peaks at night and can therefore be met in large part by wind power. As wind power is a relatively low cost zero-carbon resource, the addition of demand that can be met by wind causes power costs in the 2030 to 2040 time frame to rise quite slowly.

In the 2030 time frame, the cost of power is dominated by the deployment of gas-fired capacity and gas fuel burned at these gas plants. The decrease in existing plant sunk costs is largely offset by the cost of building new gas capacity. Even with a moderate price on carbon of \$56/tCO_2, the amount of gas burned for electricity generation puts the cost of carbon emission permits at 13 % of total electricity expenditures. Declining solar costs and increasing demand for low-carbon generation make solar energy appear as more than a sliver of cost in this time frame.

In the 2050 time frame, the average cost of power in the *Base Scenario* increases substantially relative to present-day, from \$108/MWh to \$189/MWh in real \$2013. Numerous factors drive this cost increase, with the single largest factor being the reduction of carbon emissions. The

marginal carbon price commensurate with the drastic reduction in carbon emissions by 2050 reaches almost \$1,000/tCO_2 (Table 4-1), as each extra unit of carbon that is squeezed out of the electricity sector is accompanied by the construction of transmission, storage, and low-carbon generation facilities (Figure 4-9). The emissions tuning process used in this version of the SWITCH model (Section B.8.1: Emissions) may overestimate carbon prices at deep emission reduction levels, so the actual carbon cost in 2050 could be lower than reported here. The reader is therefore asked to not put excessive weight on the 2050 carbon price, as the ability to model the price of carbon in drastic power system decarbonization scenarios is still a work in progress. Due to lower levels of emission reductions relative to 2050, pre-2050 carbon costs are not thought to have substantial overestimation from the emissions tuning process.

While \$1,000/tCO_2 is a very high price relative to present-day carbon prices, there are relatively few carbon permits in circulation (representing only 14 % of 1990 emissions). Even though the carbon price increases by 580 % between 2040 and 2050, the cost of carbon permits per MWh of electricity demand increases by only 82 %. Also, we only model electricity sector emissions and carbon prices here, but a carbon cap-and-trade program would likely cover the entire economy. The economy-wide equilibrium carbon price could therefore vary from that shown in Table 4-1 due to actions taken in sectors of the economy other than the power sector.

Table 4-1: Price of carbon permits in the electricity sector of WECC by investment period in the Base Scenario

	2020	2030	2040	2050
Carbon Price (\$2013/tCO_2)	18	56	145	998*

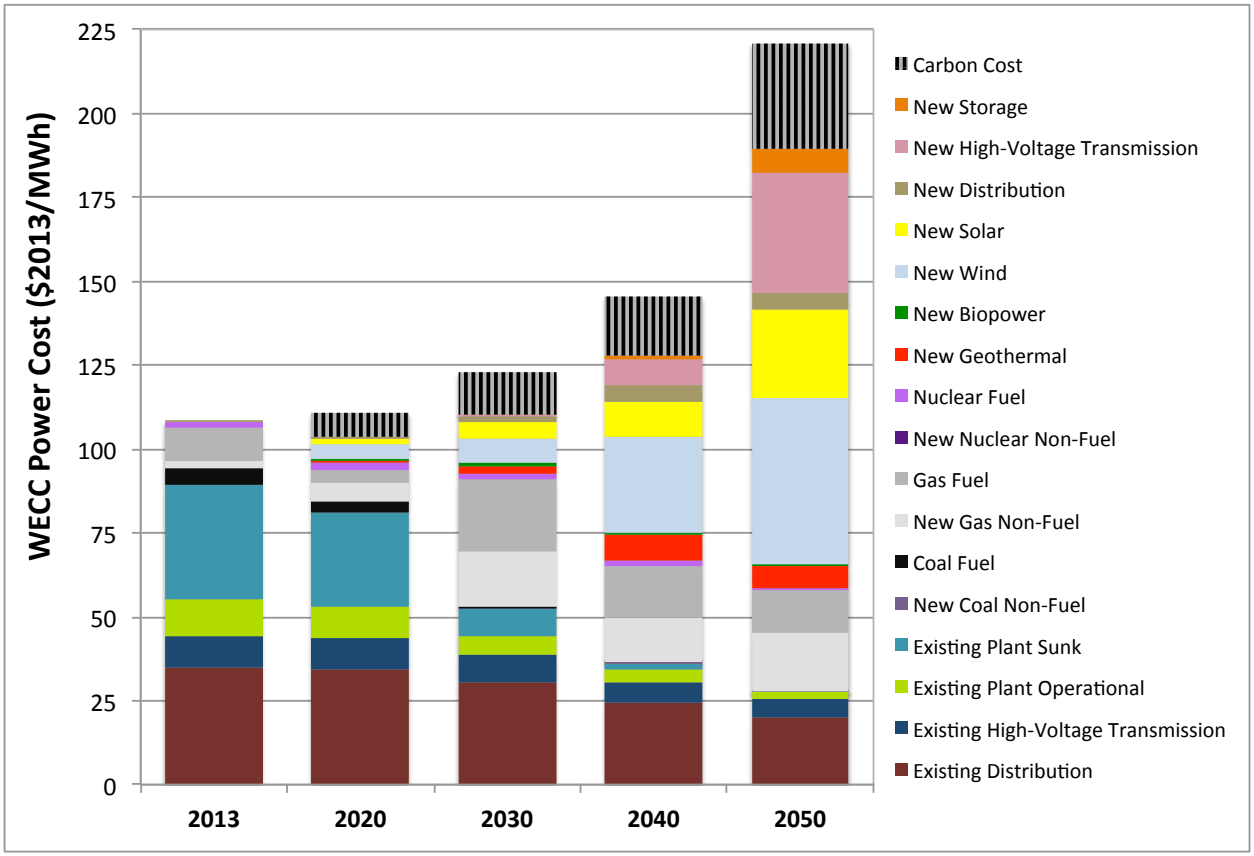
(*) The value for 2050 is tentative in the context of the modeling framework and should therefore not be given undue weight.

In an effort to spatially and temporally balance increasing fractions of variable renewable energy, the cost of power jumps in large part to the installation of substantial and transmission and storage capacity (Figure 4-9). While this trend can be seen as early as 2040, it is clear that by 2050 the balancing of low-carbon generation in space and time becomes similarly important to the generation of electricity itself from a cost perspective. This observation demonstrates that coordination of generation, transmission, and storage planning will be essential in order to meet 2050 carbon targets in a cost-effective manner. In addition, planning on the demand side through demand response and energy efficiency could be crucial in reducing the costs of transmission and storage deployment.

By 2050 the amount spent on procuring carbon permits for burning natural gas is larger than the amount spent on the fuel itself. This suggests that revenues from energy markets will be volatile as the marginal cost of the generator setting the market price will be dominated by the cost of carbon permits and will consequently be a high marginal cost. However, in many hours, the marginal generator could be wind or solar, perhaps via transmission or storage. In these hours, the marginal price of power would be zero. The price of power could therefore fluctuate between zero and a high price, with few values in between. Design of future energy markets

should take this possibility into account, and ample opportunities for generators to bid into capacity and ancillary service markets should exist in order to smooth out revenue streams.

Figure 4-9: Cost of operating the entire WECC power system in the Base Scenario per MWh of demand, broken down by cost category



Costs are specified in real $2013. Costs are not broken into the California and rest of WECC categories because much sharing of infrastructure takes place, especially in the 2050 time frame. "Non-Fuel" includes capital, and operations, and maintenance costs.

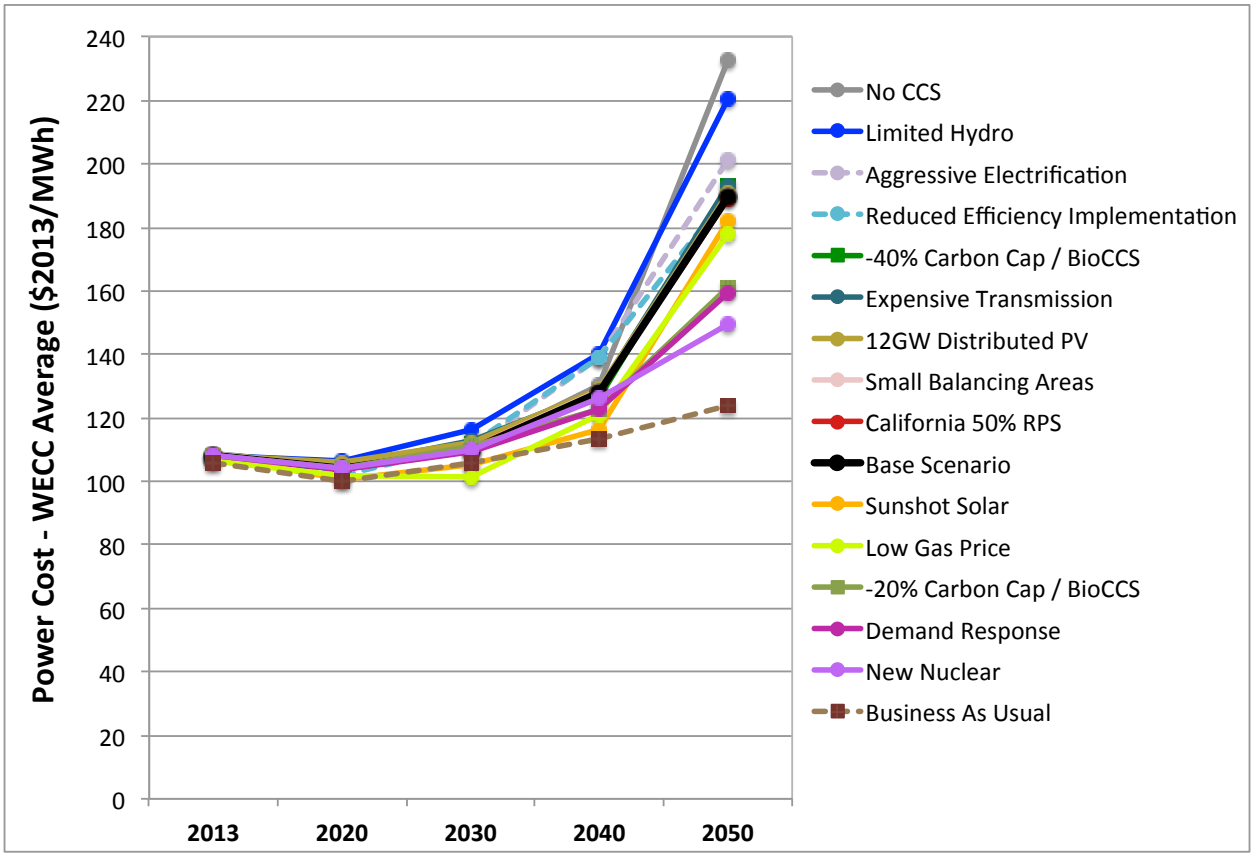
4.3.2 EXPLORATORY SCENARIOS

The WECC-wide average cost of power in 2050 is found to range between $149/MWh and $232/MWh across scenarios, a 21 to 88 % increase relative to the *Business-As-Usual Scenario* in which emissions stay flat at 100 % of 1990 levels after 2020, and a 38 to 115 % increase (in real terms) relative to the present-day cost of power. As this study assumes little technological progress by default in many parts of the electricity system, these cost estimates could represent an upper bound. However, as we do not perform detailed security-constrained power flow or transient stability checks on our results, there may be additional costs that are not captured here associated with managing contingences in the context of a power system with large percentages of energy from wind and solar power. We demonstrate that breakthroughs in the cost of solar energy or the deployment of demand response could contribute greatly to containing the cost of electricity decarbonization.

Both gas-fired CCS and nuclear power are found to be economical in the context of deep emission reductions, but neither is found to be essential to meeting 2050 emission targets. Both technologies are subject to large political and/or technological uncertainty and therefore economics may not be the driving force for installation. Deployment of nuclear power is found to be economical even at the assumed capital cost of nuclear capacity of $6.4/W ($2013) in the *New Nuclear Scenario*. Given the magnitude of cost reduction found in the *New Nuclear Scenario* relative to the *Base Scenario,* the results imply that the debate about whether to include nuclear power as part of a long-term carbon mitigation portfolio should focus less on economics and more on the societal, political, and environmental aspects of nuclear power deployment. As shown by the high cost of the *No CCS* Scenario, the deployment of moderate amounts of flexible gas CCS to balance variable renewable generation, as is found in the *Base Scenario,* is found to be one of the most effective ways to contain the costs of reducing carbon emissions, especially in California.

The cost to deploy a net carbon negative power system is negligible relative to the *Base* Scenario if biomass is made available to the electric power system instead of to the production of biofuels. Note that this cost comparison is valid in the scope of the electricity system only and does not include costs incurred and benefits received in other sectors from directing biomass to the electricity system.

Figure 4-10: Average cost of power across WECC for all scenarios



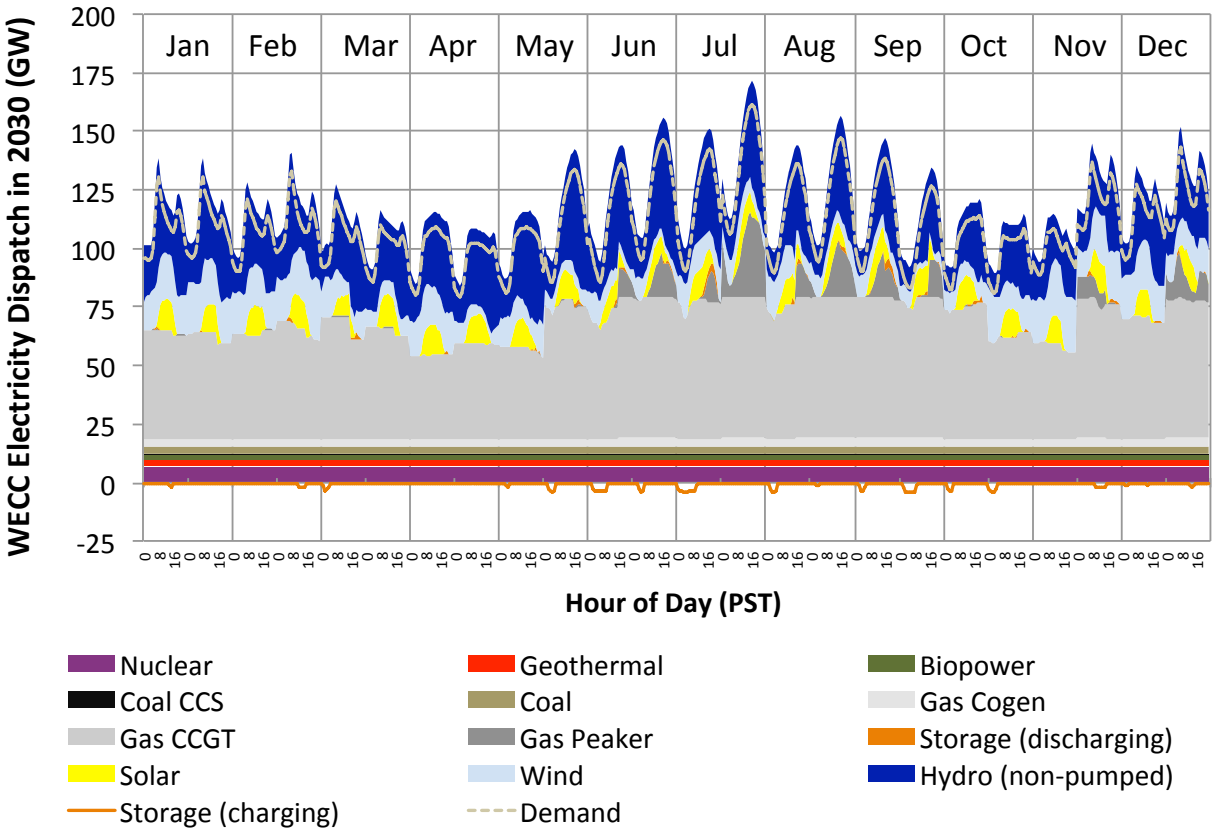
The cost of carbon permits is not included in the power cost here. Scenarios with the base carbon cap of 14 % of 1990 levels by 2050 are denoted with a round marker. Scenarios with a carbon cap different than 14 % of 1990 levels by 2050 are denoted with a square marker. Scenarios with the base demand profile are denoted with a solid line. Scenarios with a demand profile different than the base demand profile are denoted with a dashed line. Data can be found in Table D-9.

4.4 HOURLY DISPATCH

4.4.1 BASE SCENARIO

In the 2030 time frame, many natural gas combined cycle gas turbine (CCGT) generators are online in each hour (Figure 4-11). The flexibility of these generators to move their level of output up and down contributes to their successful integration into a power system in which and increasing amount of electricity is produced by variable renewable sources. The output of CCGTs is reduced in the spring and fall due to the prevalence of hydroelectricity and wind power during these seasons. The combination of hydroelectric facilities and gas generators is found to be largely sufficient to follow the net demand profile (demand minus variable renewable generation) in the 2030 time frame.

Figure 4-11: Hourly dispatch in the Base Scenario across WECC in 2030 for all months



Two days per month are represented – the median demand day and the day on which the hour of peak demand occurs. Total generation exceeds demand due to distribution, transmission, and storage losses.

In the summer months, CCGTs are almost always at full output, and additional gas resources in the form of combustion turbines are brought online to meet peak summer demands. Storage, almost exclusively existing pumped-hydro storage in the 2030 time frame, is also used during these periods of peak demand. However, for most of the rest of the year, storage is relatively dormant due the dominance of dispatchable CCGTs. In this system, much energy storage is provided in the form of fuel in the natural gas network rather than the electricity system.

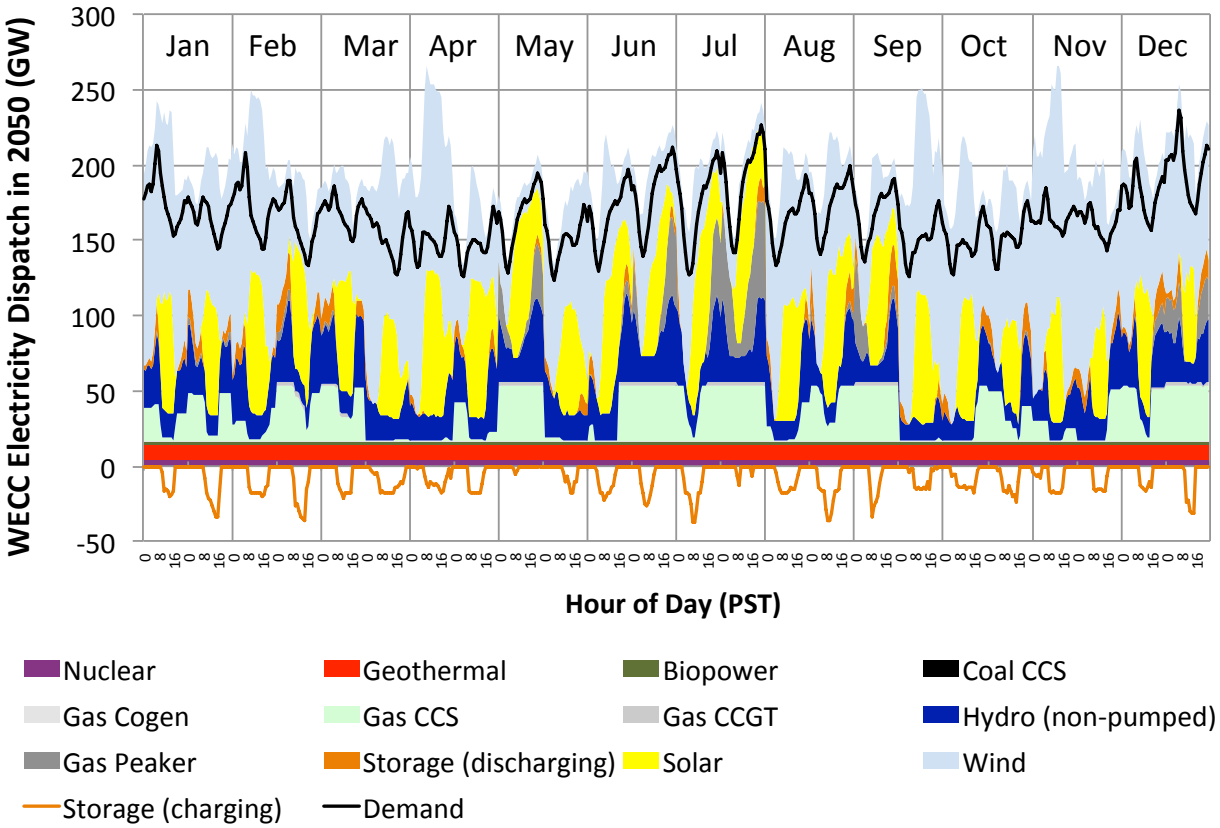
The ability of CCGTs to operate throughout the entire year (Figure 4-11) is dependent on the level of allowable carbon emissions from the electricity system, which in the 2030 time frame is still of large enough magnitude to enable the operation of some CCGTs as baseload units. While not included as a scenario in this study, it is likely that the capacity factor of CCGTs in the 2030 time frame would be reduced substantially if the carbon cap were to be tightened more quickly relative to the *Base Scenario* while keeping biomass CCS technology unavailable to the electric power system through 2030.

By 2050, almost all electricity produced from CCGTs without CCS has been eliminated from the power system due to the stringent limits on carbon emissions in this time frame. This energy

transition implies a quick change in both the source and timing of electricity generation within WECC. As can be seen in Figure 4-12, gas CCS – almost entirely CCGT technology – and non-CCS combustion turbines have considerable variability in output between seasons and even within different days of the same season. While not a full mixed-integer unit commitment model, the treatment of the costs of gas generators in the version of SWITCH used in this study captures many of the factors that influence the dispatch of CCGTs and gas combustion turbines, including start-up costs and emissions of these generators, as well reduction in efficiency from running at part-load.

Wind and solar complement each other in the seasonal timing of electricity generation. The contribution of wind electricity is notably reduced in the summer months, but solar is somewhat more productive during summer than at other times of the year. We do not model or allow seasonal storage in this study other than that embedded in the historical monthly energy availability from hydroelectric facilities. In Figure 4-12 and the 'Spring Curtailment Day' of Figure 4-13 the amount of power sometimes exceeds demand by a large margin in the spring and fall months, representing the generation of excess wind and solar energy that is not economical to store or transmit. If seasonal energy storage were to become a reality in the 2050 time frame (perhaps through the conversion to chemical energy), it could be advantageous to store wind power in spring and fall for use at other times of the year, especially summer.

Figure 4-12: Hourly dispatch in the Base Scenario across WECC in 2050 for all months

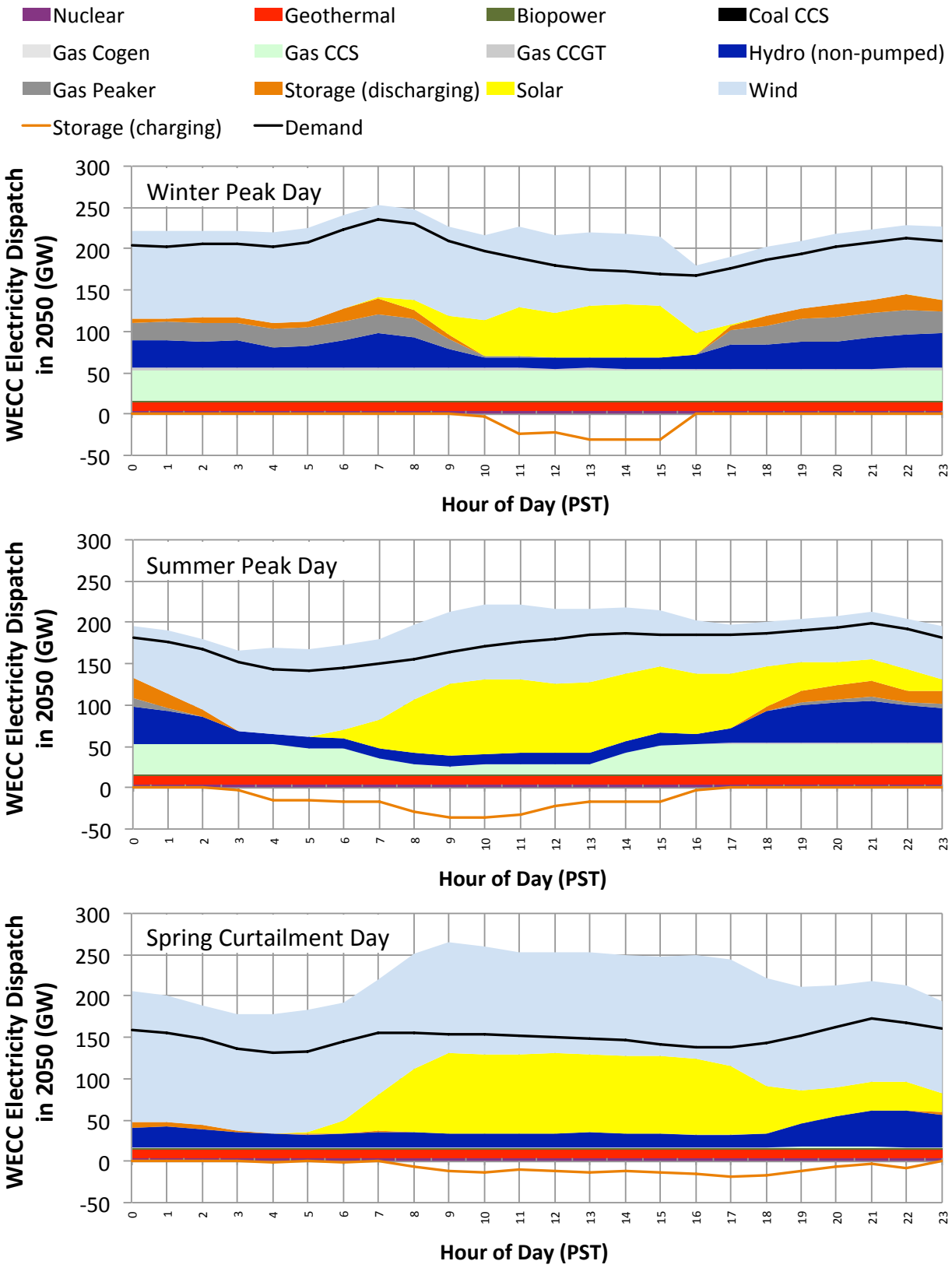


Two days per month are represented – the median demand day and the day on which the hour of peak demand occurs. Total generation exceeds demand due to distribution, transmission, and storage losses, as well as variable renewable energy curtailment. Plots of specific days can be found in Figure 4-13.

Storage is installed after 2030 to meet an increasingly stringent carbon cap, and by 2050 almost exclusively to store solar energy in the daytime for release at nighttime to serve large nighttime demands from electric heating and vehicles. This behavior is counter to the widespread idea that solar is valuable to the electric power system because of its coincidence with peak demand. While the aforementioned idea is true at relatively low penetrations of solar power, the marginal value of solar electricity in the daytime will drop off sharply with increasing penetration of solar generation capacity. As the cost of zero-carbon energy from solar is relatively low compared to other technologies, the timing of production becomes the limiting factor in increasing solar development. Energy storage in the form of batteries, compressed air energy storage, and solar thermal plants with thermal energy storage is therefore installed to aid in moving solar energy to the nighttime. Similar behavior is seen below in the *Demand Response Scenario*.

For the purpose of brevity we do not include here a discussion of the hourly dispatch of exploratory scenarios other than the *Demand Response Scenario*.

Figure 4-13: Hourly dispatch in the Base Scenario across WECC in 2050 for selected days

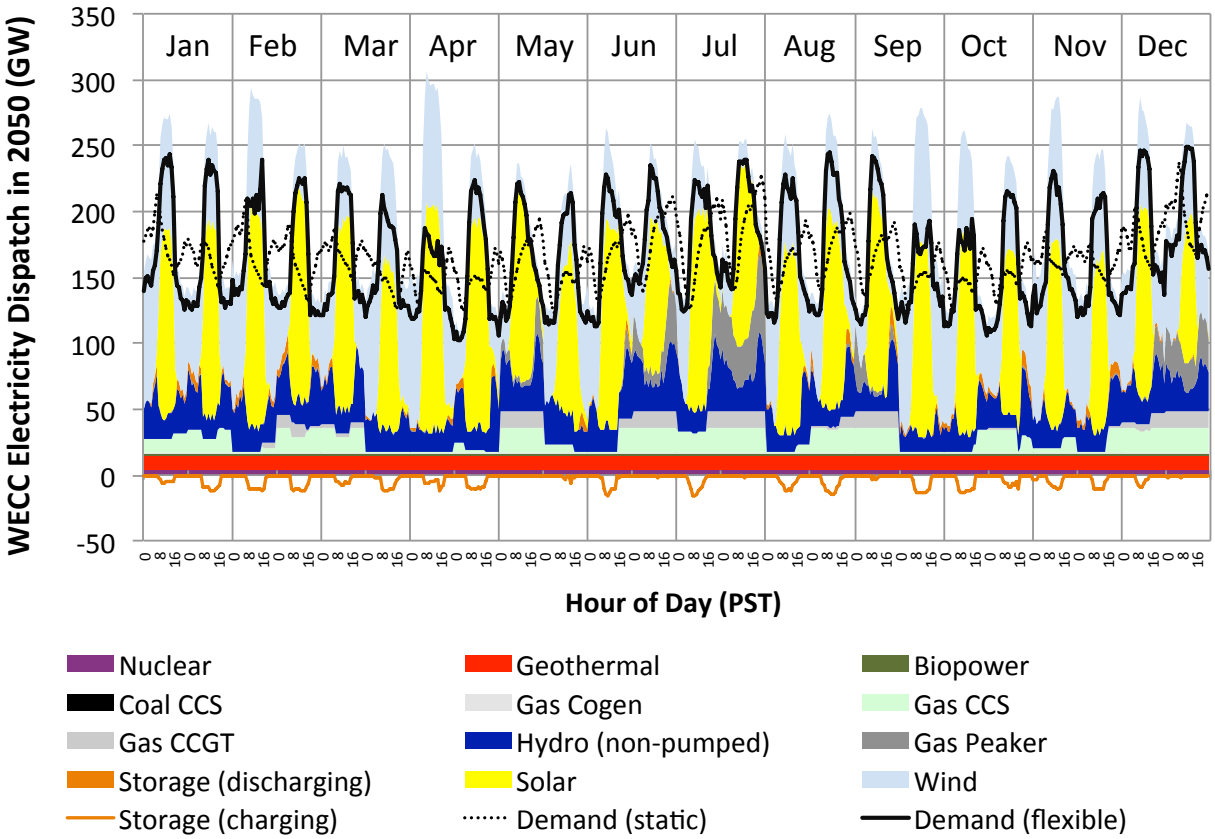


4.4.2 DEMAND RESPONSE

In the *Demand Response Scenario* we assume that demand response is costless both to dispatch and to procure (see Section 3.6: Demand Response). While this assumption is certainly liberal, it can be assumed that planning and operation of low-cost demand response would be similar to that which is shown here. This is especially true when viewed in the context of the amount of storage installed in cases without demand response as storage is expensive and is still installed at multi-GW scale across many scenarios.

In 2030, the magnitude of demand response assumed to be available in the *Demand Response Scenario* is not very large relative to demand. We therefore only discuss the 2050 time frame here, in which the magnitude of demand response is much larger.

Figure 4-14: Hourly dispatch in the Demand Response Scenario across WECC in 2050 for all months



Two days per month are represented – the median demand day and the day on which the hour of peak demand occurs. 'Demand (flexible)' represents the system demand after demand shifting via demand response, whereas 'Demand (static)' is the demand profile before demand shifting. Total generation exceeds demand due to distribution, transmission, and storage losses, as well as variable renewable energy curtailment.

In this study, by default we assume predominantly nighttime charging of electric vehicles. However, in the *Demand Response Scenario*, some of this electric vehicle demand is moveable to the daytime at the discretion of the system planner/operator. The cost of solar power in the 2050 time frame ($2.1/$W_p$ for central station photovoltaics) is such that it is economically favorable to move demand into the daytime to be met with solar power. Demand response is seen to substitute almost directly for storage technologies as it serves a similar function but is zero-cost as formulated here. We do not explore a scenario that has both low solar costs (as in the *Sunshot Solar Scenario*) and demand response, but it is very likely that the demand response behavior exhibited here would be even more prominent in such a scenario.

Demand response is usually thought of as a technology that decreases peak demand, but the dispatch of demand response in Figure 4-14 shows an increase in peak demand upon deployment of demand response. When substantial wind and solar power capacity is installed, demand response provides benefit to the power system when demand is moved from difficult hours on which to supply demand with wind and solar power to easier hours. The increase in peak demand highlights the viability of solar photovoltaic technology in the 2050 time frame, as SWITCH is willing to make the tradeoff to install additional distribution capacity in order to absorb additional solar energy via demand response. In other words, it is less expensive to install new distribution capacity to facilitate additional solar energy than it is to install other forms of infrastructure to aid in the decarbonization of the power system. This result must be understood in the context of demand response being a zero cost resource in the *Demand Response Scenario*. An increase in the cost of demand response would decrease the amount of new distribution capacity built.

4.5 SPATIAL ENERGY GENERATION AND TRANSMISSION

In the 2050 time frame, Rocky Mountain wind is extensively developed due in large part due to high wind capacity factors in this region. Wind power generated in Wyoming is sent west towards Salt Lake City, northwest towards the Pacific Northwest and Alberta, and to a lesser extent southwest towards Utah, Nevada, and California. Wind power generated in New Mexico is sent west towards Arizona and California.

Hydroelectric power that has been traditionally transmitted from the point of generation in Pacific Northwest to demand centers in California is used more locally in the Pacific Northwest by 2050. Increasing amounts of energy from variable renewable generation both located inside and also sent to the Pacific Northwest are balanced by hydroelectric generation, leaving less available hydroelectric for import into California.

Three observations imply that the Pacific coast is more difficult to decarbonize than the inland portions of WECC:

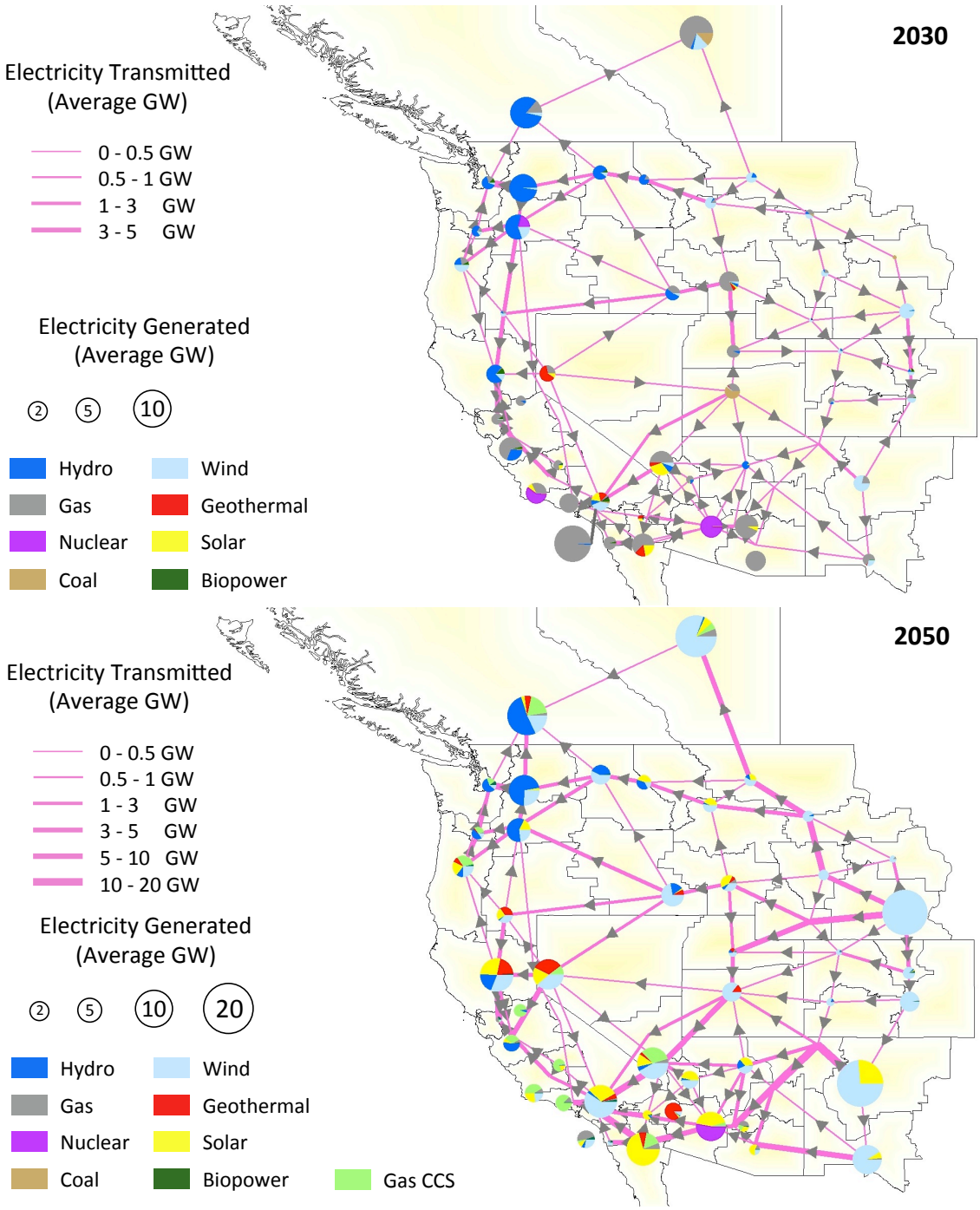
- Very little natural gas generation either with or without CCS is found far away from the Pacific coast.
- Variable renewable generation is generally only curtailed outside of California's footprint

- Almost all new transmission capacity connects east to west (Section 4.6: Spatial New Transmission Capacity Built)

This set of observations could serve as an argument to engage states that have been traditionally less politically inclined to deploy long-term climate or renewable energy policy, as their costs to implement policies similar to California GHG targets or RPS standards may be substantially less on a per MWh basis than is the case for California. The linkage between climate and/or renewable policies between many states would bring down the cost to meet these policies for all states involved.

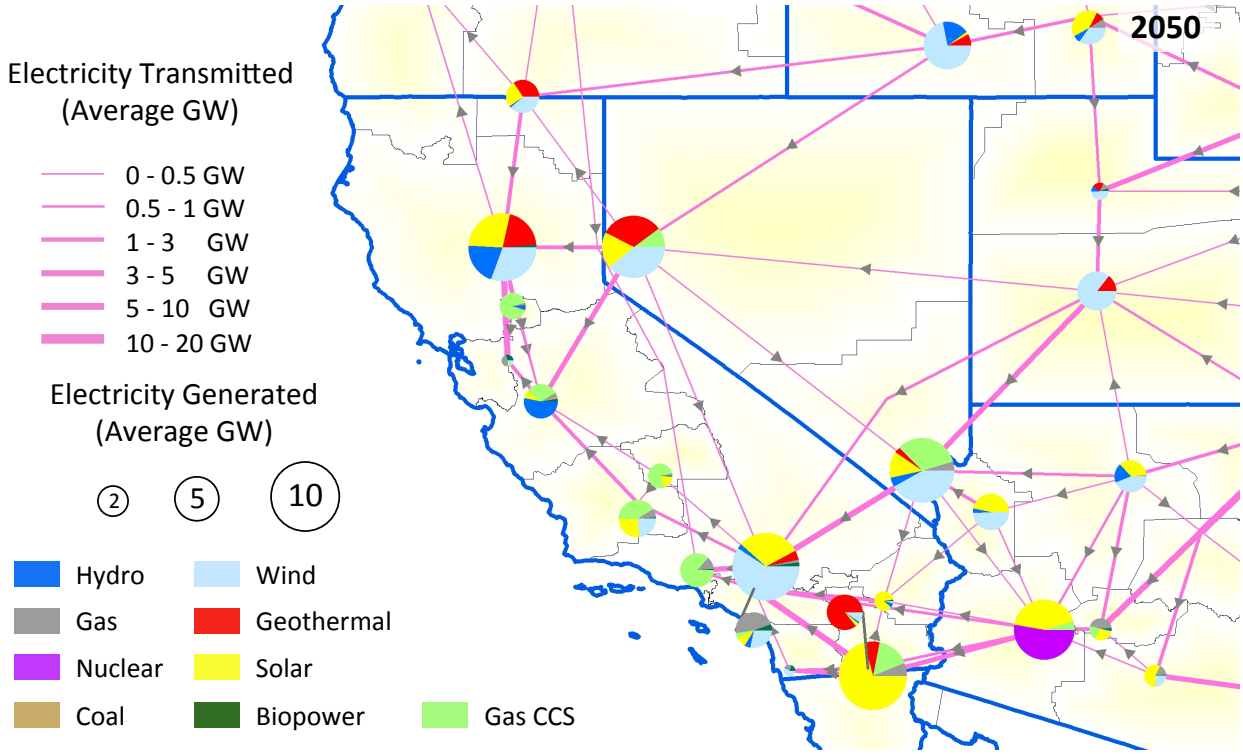
On an average basis in 2050, California is a net power importer over every major transmission path modeled in this study. The prevalence of gas CCS in and near California reinforces the idea that California is a relatively difficult area to decarbonize relative to other areas in WECC. Given the costs input to this study, by 2050 on an energy basis, gas CCS is an expensive form of generation relative to high quality solar or wind resources. Much of the natural gas generation of both non-CCS and CCS varieties is found in the Los Angeles basin. Local capacity constraints in the Los Angeles basin are not explicitly enforced in this study as they are currently difficult to model far into the future. Despite this omission, the Los Angeles basin appears to be one of the most economically favorable areas to consume natural gas. The favorable economics of using natural gas in the Los Angeles basin should be taken alongside regional planning concerns including land use, criteria pollutant emissions, grid reliability, etc. to form a complete picture about the long-term future of natural gas in this area.

Figure 4-15: Average hourly generation by fuel within each SWITCH load area, and average transmission hourly flow between load areas in 2030 and 2050



The size of each pie represents the amount of energy generated in the load area in which the pie resides. Transmission lines are modeled along existing transmission paths, but are depicted here as straight lines for clarity. These maps portray average generation and transmission over the course of an investment period, and as such, dispatch of the electric power system may vary greatly from that depicted here in some hours.

Figure 4-16: Zoom in on California of Figure 4-15 in 2050

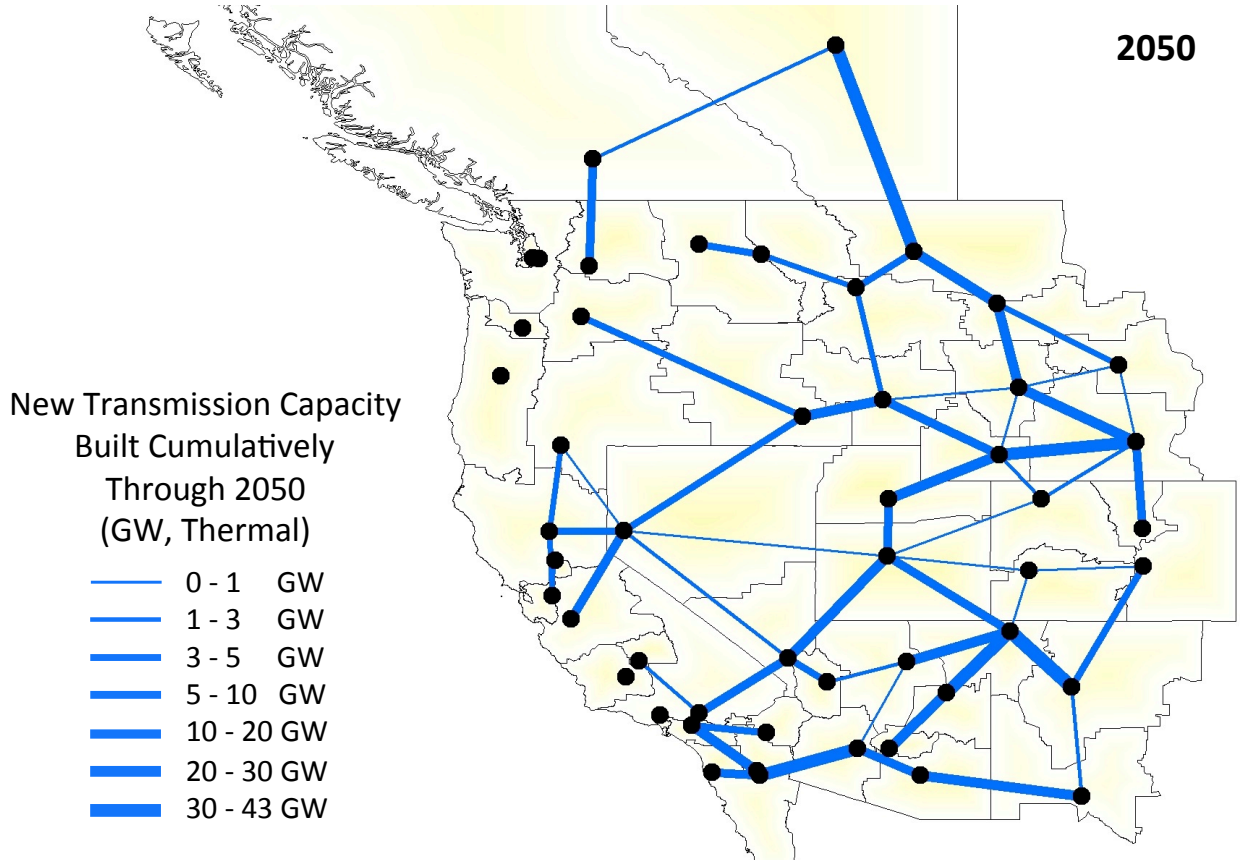


4.6 SPATIAL NEW TRANSMISSION CAPACITY BUILT

By 2030, little new long-distance, high-voltage transmission capacity across WECC is built in the *Base Scenario* due to the deployment of efficiency measures and gas-fired generation. Most new transmission is built after 2030 to enable the integration of increasing fractions of variable renewables.

By 2050 (Figure 4-17), the WECC transmission system has been reinforced in order to bring electricity generated in the eastern portions of WECC to demand centers in the west. The largest new northern lines increase the connection between Wyoming wind generation and north central WECC, primarily serving demand centers in Salt Lake City and Alberta. The largest new southern lines aid the deployment of wind and solar power across the Desert Southwest. Transmission lines that exist today on the Pacific coast (Appendix Figure A-2) are found to be mostly sufficient to move power up and down the coast, in large part due to demand growth in the Pacific Northwest that reduces the amount of hydroelectricity sent southward to California.

Figure 4-17: Spatial deployment of new transmission capacity built throughout WECC by 2050



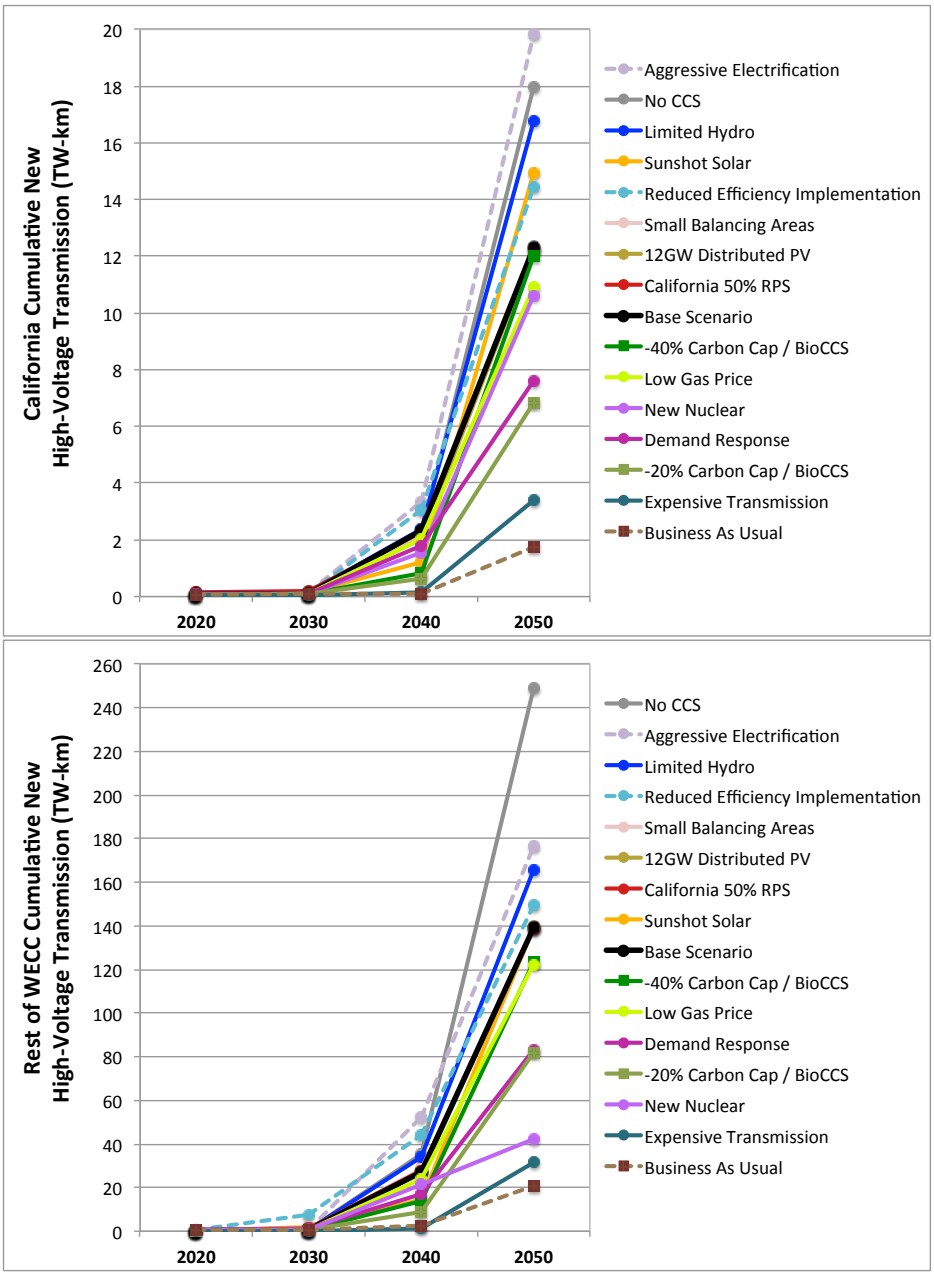
The values shown represent the thermal capacity of transmission lines and are therefore not de-rated to reflect transmission path constraints. To estimate the AC transmission path capacity from the thermal capacity, multiply by a factor of 0.59.

4.7 TRANSMISSION CAPACITY

Transmission is one of the many sources of flexibility that can be used to integrate variable renewable energy. The build-out of transmission shown here therefore generally scales with the magnitude of variable renewable energy. The *Reduced Efficiency Implementation Scenario* and the *Aggressive Electrification Scenario* build more transmission capacity than the *Base Scenario* because these two scenarios have additional demand relative to the *Base Scenario* while maintain the same cap on carbon emissions.

The *Expensive Transmission Scenario* shows the least reliance on new transmission of any scenario that has deep carbon emission reductions. In this scenario, the cost of new long-distance, high-voltage transmission is three times larger than in the *Base Scenario.* California therefore relies less on imports and develops more in-state generation capacity in the *Expensive Transmission Scenario* than in any other scenario. The rest of WECC generation capacity is reduced for the same reason.

Figure 4-18: Cumulative new high-voltage, long distance transmission capacity installed in California (top) and the rest of WECC (bottom) for all scenarios



Note the difference in scale on the top and bottom panels. The capacity shown represents thermal capacity of transmission lines and is therefore not de-rated here to reflect transmission path constraints (the average thermal-to-path derating factor used in this study for AC transmission lines is 0.59). Scenarios with the base carbon cap of 14 % of 1990 levels by 2050 are denoted with a round marker. Scenarios with a carbon cap different than 14 % of 1990 levels by 2050 are denoted with a square marker. Scenarios with the base demand profile are denoted with a solid line. Scenarios with a demand profile different than the base demand profile are denoted with a dashed line.

4.8 OPERATING RESERVES

Operating reserves are maintained to ensure that electricity supply and demand remain in balance on the sub-hourly timescale. The amount of reserves that must be kept at any given time is a function of the amount of variability in the net demand profile (demand minus variable renewable generation). The net demand profile is in turn a function of the magnitude of demand and also of the amount of power being generated from variable renewable generation. In this study we model the commitment of both spinning and quickstart reserves, thereby covering down to the five-minute timescale. We do not explicitly dispatch the power system in five-minute increments, but rather ensure that enough reserves are held at any given time to ensure reliability.

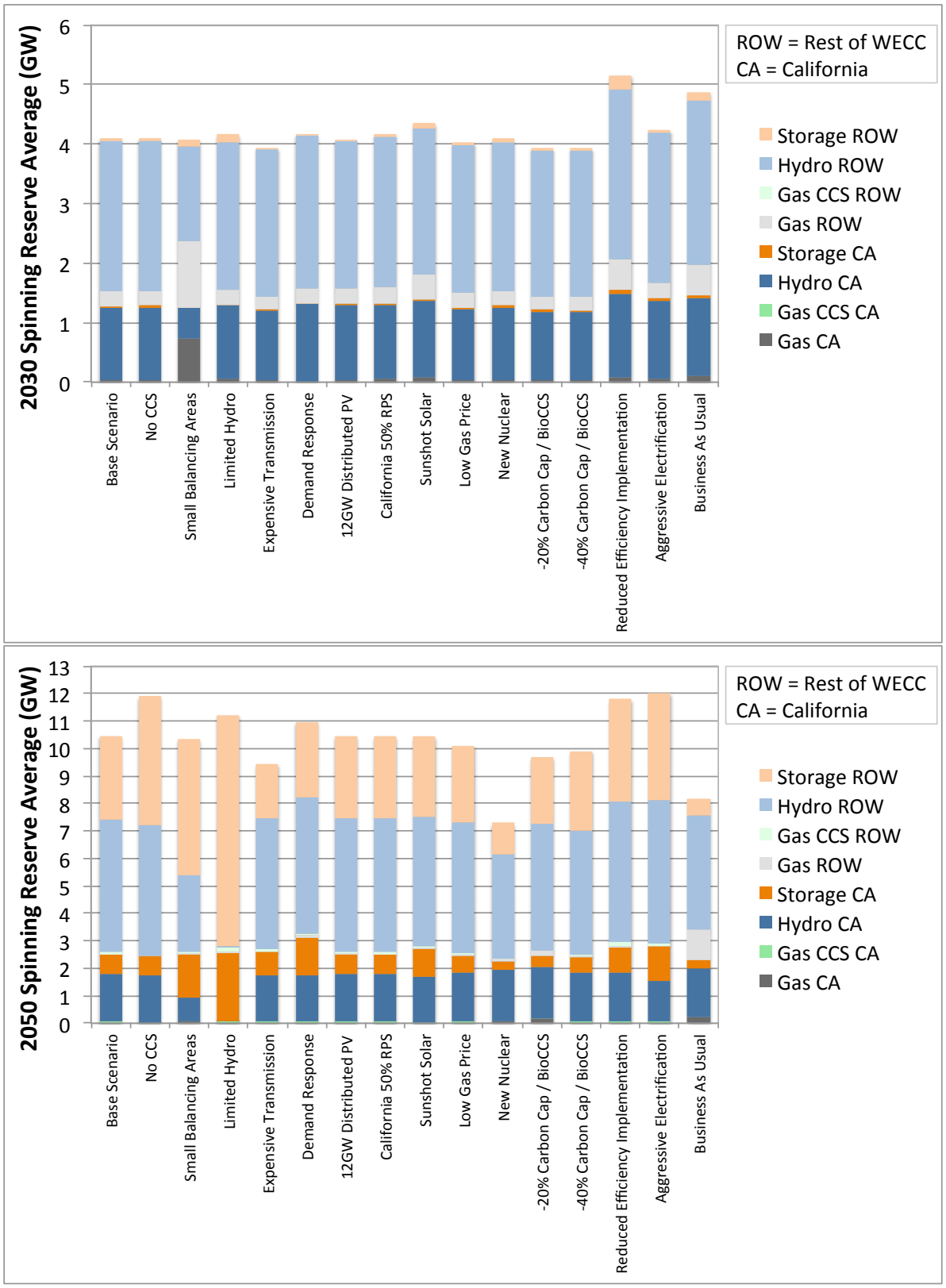
In order to balance variable renewables and to meet increased demand originating primarily from electrification of vehicles and heating, the magnitude of both spinning and quickstart reserve requirements more than doubles between 2030 and 2050. In this study we allow natural gas, hydroelectric, and storage facilities to provide spinning and quickstart reserve. Though demand response could contribute substantially to operating reserves, we do not explore this possibility in this study due to a lack of data on the long-term potential of this resource. We limit the amount of operating reserve that hydroelectric facilities can provide to 20 % of the facility turbine capacity in order to reflect wildlife and stream flow constraints that can limit fast changes in water flow through dams.

In the 2050 time frame, the *No CCS Scenario* commits the highest amount of operating reserve capacity relative to demand of any scenario because it has the most variable renewable generation. The *No CCS Scenario* has a smaller magnitude of reserve commitment in 2050 than either the *Reduced Efficiency Implementation Scenario* or the *Aggressive Electrification Scenario*, but both of these scenarios have larger total demand than the *No CCS Scenario*. Both the *Business-As-Usual Scenario* and the *New Nuclear Scenario* have smaller operating reserve requirements in 2050 than the rest of the scenarios investigated because they generate relatively small percentages of total energy from variable renewables.

4.8.1 SPINNING RESERVE

In this study, in both 2030 and 2050, hydroelectric facilities are the largest contributors to spinning reserves, providing zero-emission balancing for variable renewables. Storage is also used extensively in 2050 to provide spinning reserves and is preferred to gas generation because of carbon emissions incurred by operating gas plants at part load. By 2050 there is little room in the carbon cap to accommodate spinning reserves from gas-fired generation. A small fraction of spinning reserve is provided by compressed air energy storage in the *Base Scenario* in 2050 (~100 MW on average), further corroborating the idea that even very low carbon sources of spinning reserve commitment are economically disfavored relative to zero carbon sources as the carbon cap becomes increasingly stringent over time.

Figure 4-19: Average hourly spinning reserve commitment in 2030 and 2050 for California and the rest of WECC for all scenarios



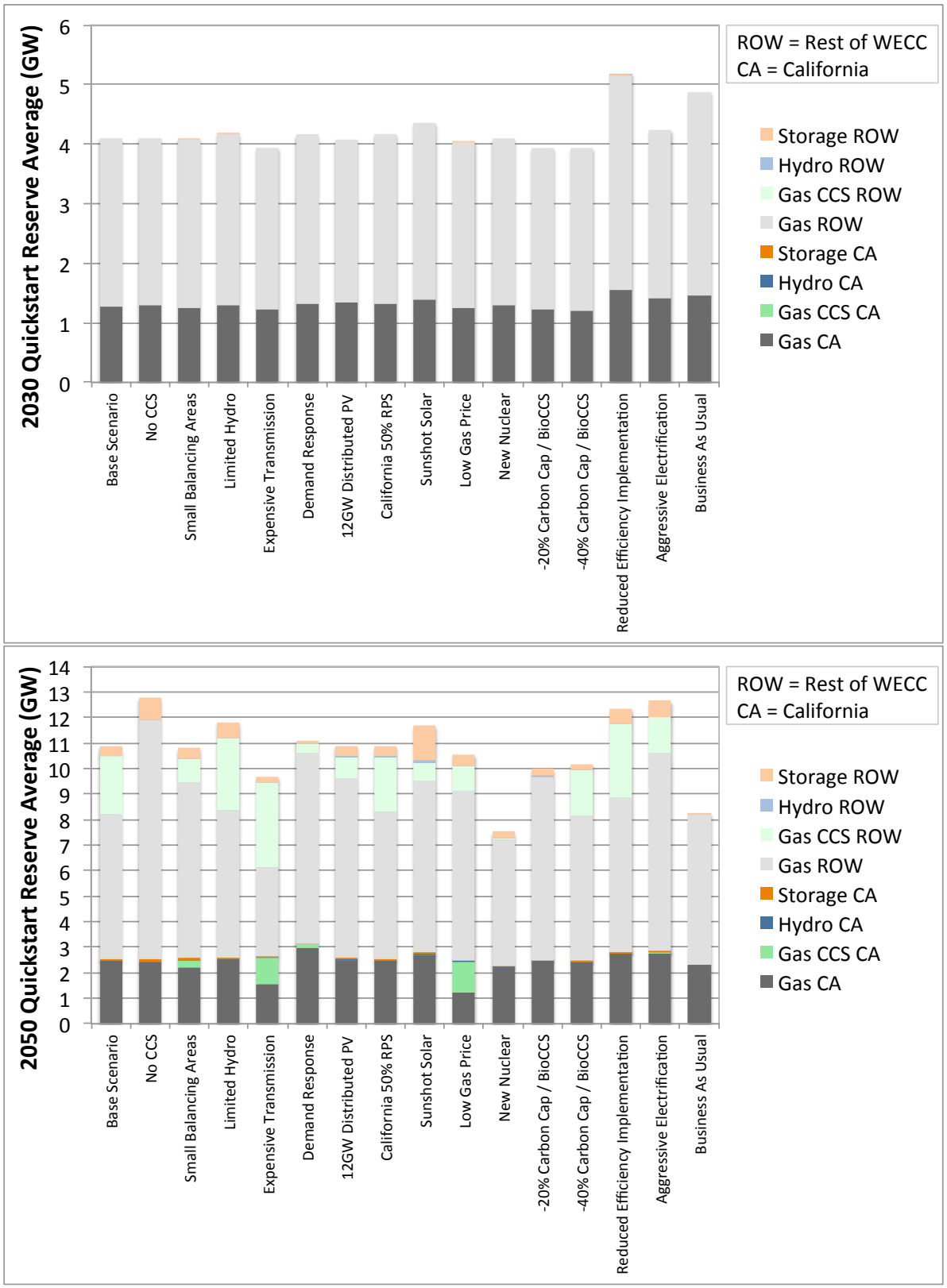
These results suggest that hydro and zero-emission storage should be encouraged to participate in sub-hourly reserve markets to the full extent possible. We do not investigate the potential for demand response to participate in sub-hourly reserve markets in this study, but demand response could also constitute a large source of zero-emission sub-hourly reserve and should also be encouraged. We also do not investigate short time duration storage such as flywheels, which could play a role in short timescale zero-emission reserve markets.

Balancing operating reserves over smaller geographic areas and reducing hydro availability are two factors that are shown to limit the hydro contribution to spinning reserves in favor of storage. The commitment of large fractions of spinning reserves from gas in 2030 in the *Small Balancing Areas Scenario* demonstrates the advantage of pooling operating reserves into large balancing areas. This scenario is conservative as it assumes that there is no trading of operating reserves between different balancing areas. In the *Base Scenario* we do not explicitly model the dependence of operating reserve commitment on transmission constraints inside each of the six large sub-regional balancing areas that are modeled in Section B.4.1: Treatment of Operating Reserves. It may therefore be the case that for hours in which intra-balancing area transmission constraints are binding, the commitment of operating reserves in the *Base Scenario* is too liberal. Some gas-fired spinning reserve commitment may therefore be justified in the 2030 time frame, in between the amount found in the *Base Scenario* and the *Small Balancing Areas Scenario*. Future versions of SWITCH will attempt to more accurately model transmission constraints in the commitment of operating reserves.

4.8.2 QUICKSTART RESERVE

Quickstart reserves, which are offline and do not contribute to emissions unless called upon, are provided largely by gas generation across all scenarios and investment periods. In 2030, quickstart reserves are provided exclusively by conventional gas generation, but by 2050 some reserves are also provided by storage and gas CCS. In contrast to the dispatch of spinning reserves, changing the size of balancing areas or limiting energy from hydroelectric facilities makes only small differences in the commitment of quickstart reserves. Despite the fact that we do not let demand response participate in operating reserves in this study, the inclusion of demand response in the *Demand Response Scenario* reduces the amount of quickstart reserve from gas CCS in 2050 because little gas CCS is built in this scenario. In contrast, more quickstart reserves are committed from gas CCS in the *Expensive Transmission Scenario* and the *Low Gas Price Scenario* compared to the *Base Scenario* because less gas CCS capacity is built by 2050 in the two exploratory scenarios. Gas CCS is found to provide a substantial fraction of quickstart reserve in many scenarios, a result that is dependent on the ability of the CCS system to ramp up as quickly as the gas generator itself.

Figure 4-20: Average hourly quickstart reserve commitment in 2030 and 2050 for California and the rest of WECC for all scenarios



4.9 CARBON EMISSIONS

In this study we investigate only CO_2 emissions and not other non-CO_2 greenhouse gasses. CO_2 is by far largest source of greenhouse gas emissions from power generation.

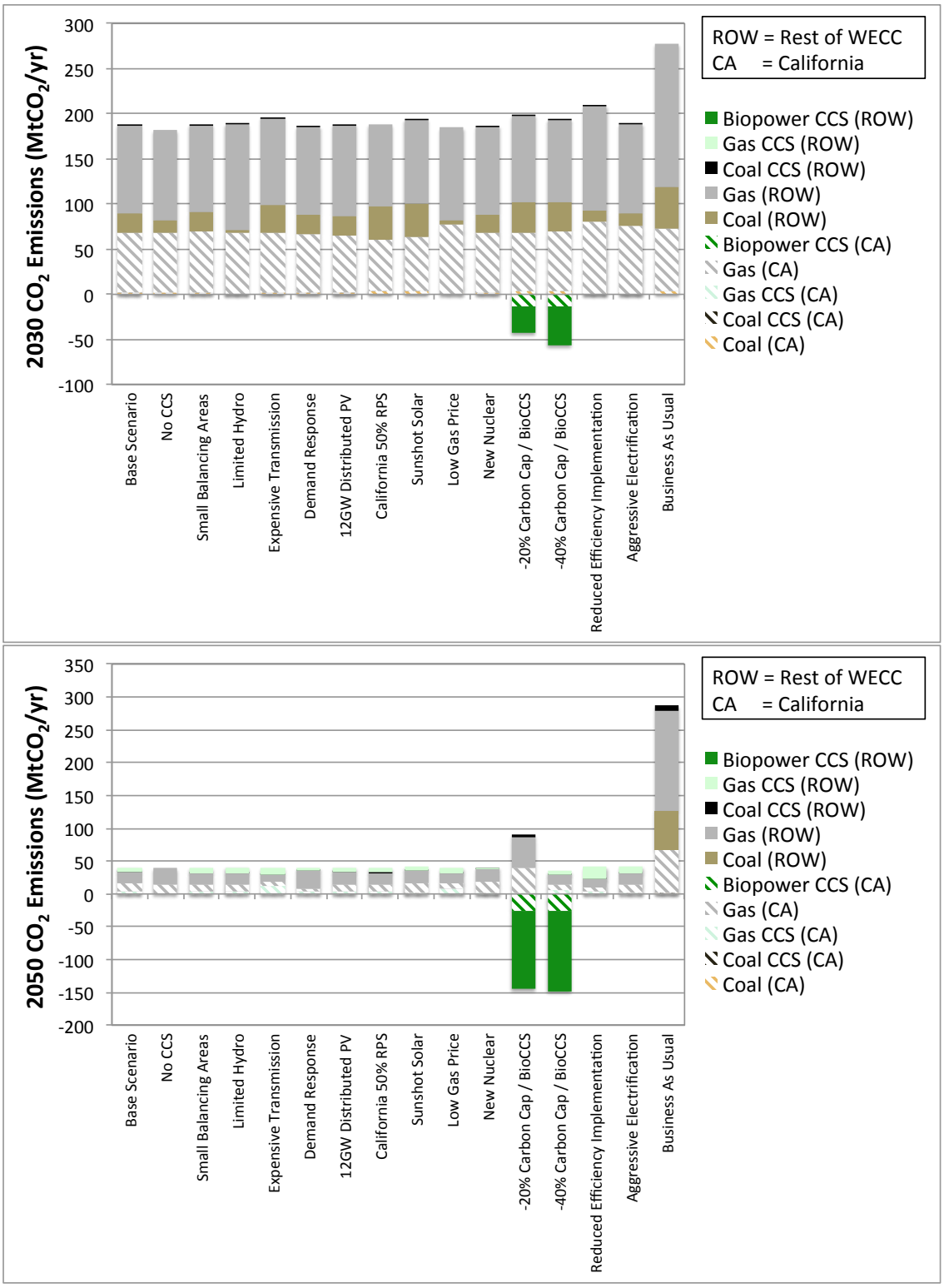
By 2030, natural gas generation is the largest contributor to carbon emissions in all scenarios as coal is gradually phased out. However, a small amount of coal generation is still online in this time frame despite the cap on emissions, showing that there is still some flexibility at the level of emissions allowed in 2030 (71 % of 1990 levels in the *Base Scenario*).

By 2050, the amount of natural gas in the system is limited by the cap on carbon emissions and, unless carbon emissions from gas are sequestered, gas is phased out in favor of renewables or nuclear. At current fuel price and generator cost projections, carbon sequestration plays a relatively minor role in the generation mix. GASES CCS is used to balance variable renewables, but is not generally operated in baseload mode in large part due to incomplete carbon emission capture. Coal CCS is not generally economical and is deployed in very small amount amounts relative to the scale of the WECC power system.

We assume that CCS technology captures 85 % of the carbon content of the input fuel, but as CCS technology requires more input fuel per net MWh generated in order to operate the CCS system, this amounts to an emission reduction per net MWh generated of 78 % relative to the non-CCS generator of the same type (Section A.10.2: New Generator and Storage Project Parameters). Should CCS systems become more effective at capturing a larger than 85 % fraction of input carbon while not substantially increasing costs, gas CCS could become a more important part of the electricity system under deep carbon emission reductions.

If available, biomass CCS technology can provide negative emissions, increasing the allowable emissions of non-sequestered fossil fuels in the electric power sector and other sectors of the economy. The amount and cost of biomass available to the electric power sector (Section A.8: Biomass Solid Supply Curve) will determine the amount that could be sequestered, but with the levels of biomass availability investigated here, it would appear that sequestering ~150 $MtCO_2$/yr of carbon emissions from biomass would be feasible and perhaps even cost-effective (Section 4.3: Power System Cost). Our results suggest that within WECC, the conversation about the deployment of CCS should be shifted away from coal and towards dispatchable natural gas and possibly biomass.

Figure 4-21: Yearly CO_2 emissions by source in California and the rest of WECC in 2030 and 2050 for all scenarios



Emission sources in California are depicted with sideways stripes. Emission sources in the rest of WECC are depicted with solid colors.

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APPENDIX A DATA DESCRIPTION

A.1 LOAD AREAS

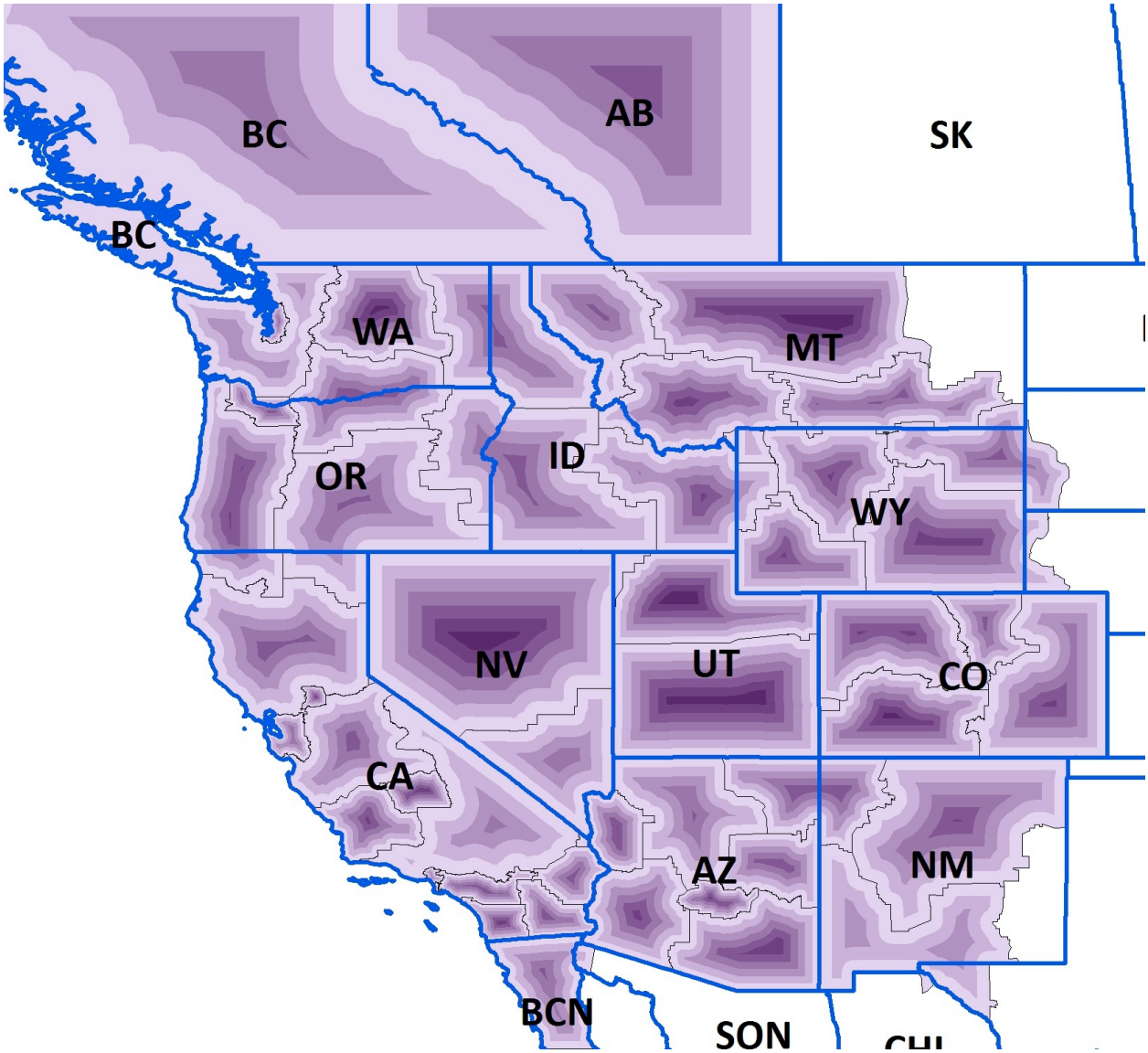
A.1.1 GEOSPATIAL DEFINITION

The version of SWITCH used in this study divides the synchronous western North American electric power interconnect – the geographic extent of the Western Electricity Coordinating Council (WECC) – into 50 load areas. These areas represent sections of the electricity grid within which there is significant existing local transmission and distribution, but between which there is limited existing long-range, high-voltage transmission. Consequently, load areas are geographic regions between which transmission investment may be beneficial.

Load areas are divided predominantly according to pre-existing administrative and geographic boundaries, including, in descending order of importance: state lines, North American Electric Reliability Corporation (NERC) control areas, and utility service territory boundaries. Utility service territory boundaries are used instead of state lines where a large amount of high-voltage transmission connectivity is present between states within the same utility service territory. The location of mountain ranges is considered because of their role as natural boundaries to transmission networks. Major metropolitan areas are included because they represent localized areas of high electrical demand.

In addition, load area boundaries are defined to capture as many congested transmission paths as possible (WECC, 2009). These pathways, which consist of important bundles of existing transmission lines, are some of the first places where transmission is likely to be built. Exclusion of these pathways in definition of load areas would allow power to flow without penalty along overloaded transmission paths.

Figure A-1: Geographic overlay of the 50 SWITCH load areas with US states, Canadian provinces, and Mexican states



States/provinces are given blue borders and are denoted using their abbreviations in black letters. Load area boundaries are represented with thin black lines and the territory that each load area encompasses is represented with a purple gradient. The purple gradient is utilized here because in many cases, load area boundaries overlap with state lines.

A.1.2 COST REGIONALIZATION

Costs for constructing and operating power systems infrastructure vary by region. To capture this variation, all costs in the model are multiplied by a regional economic multiplier derived from normalized average pay for major occupations in United States Metropolitan Statistical Areas (MSAs) (Bureau of Labor Statistics, 2009). Counties that are not present in the listed MSAs are given the regional economic multiplier of the nearest MSA. These regional economic multipliers are then assigned to load areas weighted by the population within each county

located within each load area. Economic multipliers for the US portion of WECC range from 0.88 to 1.18.

Data for Canadian and Mexican economic multipliers are estimated at 1.05-1.1 for Canada and 0.85 for Baja California Norte. These values will be updated in future versions of the model.

A.2 HIGH VOLTAGE TRANSMISSION

A.2.1 GENERAL APPROACH

SWITCH treats the electrical transmission system as a generic transportation network with maximum transfer capabilities equal to the sum of the thermal limits of individual transmission lines between each pair of load areas, de-rated by a path derating factor. As is common in long-term electricity planning studies, we model the capabilities of the transmission network, and the cost of upgrading those capabilities, rather than simulating the physical behavior of the transmission network directly. SWITCH does not currently model the electrical properties of the transmission network in detail and, as such, is not a power flow model based explicitly on Kirchhoff's laws. Optimal power flow models identify the least expensive dispatch plan for existing generators to meet a pre-specified set of loads, while respecting the physical constraints on the flow of power on every line in the network. They become non-linear when investment choices or AC properties are included, making them computationally infeasible for optimizing the evolution of the power system, especially when modeling a large area with many distinct time points.

Energy loss from power transmission is a function of the square of the current through the line and is thus also difficult to include in detail in a large linear program. We make the approximation that 1 percent of power transmitted along each transmission path is lost for every 161 km (100 miles) over which it is transmitted. This value is representative of typical loss factors for high voltage, long distance transmission.

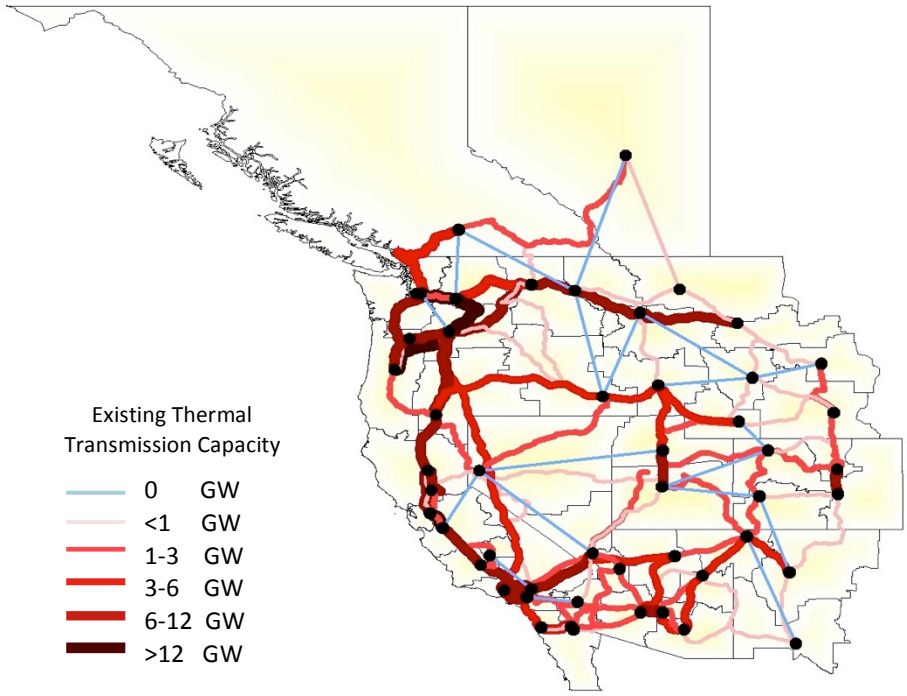
The existing thermal limits of transmission lines between load areas is found by matching geolocated Ventyx transmission line data (Ventyx, 2012) with Federal Energy Regulatory Commission (FERC) data on the thermal limits of individual power lines (FERC, 2012). In total, 105 existing inter-load-area transmission corridors are represented in SWITCH. The largest capacity substation in each load area is chosen by adding the transfer capacities of all lines into and out of each substation within each load area. It is assumed that all power transfer between load areas occurs between these largest capacity substations, using the corresponding minimum distance along existing transmission lines between the substations as calculated using Dijkstra's algorithm.

If no existing path is present, new transmission can be installed between adjacent load areas assuming a distance of 1.3 times the straight-line distance between largest capacity substations of the two load areas. The factor of 1.3 is chosen as it represents the average increase in distance relative to the straight-line distance between two large substations that a transmission line incurs when traversing land in Western North America. This factor is calculated as the distance-weighted ratio of exiting transmission line length to straight-line distance between

largest capacity substations within WECC. In total, 19 new inter-load-area transmission corridors are represented in SWITCH.

All new transmission built by SWITCH is assumed to be Alternating Current (AC).

Figure A-2: Existing thermal transmission capacity between load areas



See section A.2.2 for a description of how thermal capacity is derated in SWITCH. Transmission paths that do not currently have any existing capacity, but are given the option to install new capacity in SWITCH are shown in light blue. The largest capacity substation in each load area is depicted by a black dot. This picture represents a simplified picture of the transmission system as capacity is aggregated here along a single transmission corridor between any pair of load areas.

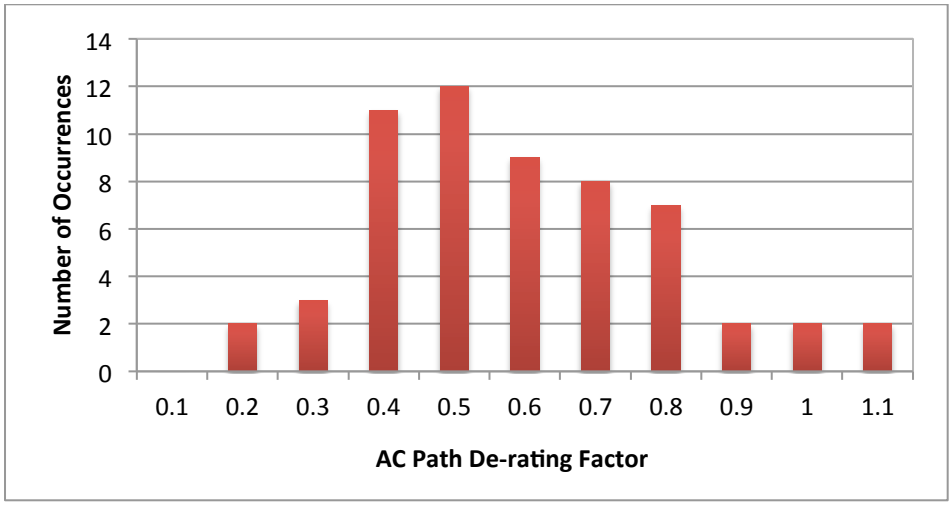
A.2.2 DERATING OF THERMAL LIMITS TO PATH LIMITS

The amount of power than can be safely transferred along a bundle of individual transmission lines (a transmission "path") is less than or equal to the thermal rating of the individual transmission lines in the bundle. Several factors can contribute to this decrease in aggregate power transfer capability relative to thermal limits, including stability concerns, loop flows, voltage concerns, power factors less than unity, overloading of individual transmission lines within the bundle, etc. The ratio of path transfer capacity to the sum of individual line thermal limits will be referred to here as the path derating factor. Many, but not all of these concerns are specific to AC transmission lines, and as such AC transmission paths tend to have path derating factors further from unity than direct current (DC) paths.

It is not currently possible to model the complete set of considerations that define path derating factors within a long-term planning model such as SWITCH. Our approach, on average,

neither over nor underestimates the power transfer capabilities of the high voltage transmission system. In this approach, the thermal limit of each transmission path is given a path derating factor equal to the present-day WECC-wide capacity-weighted average path derating factor. In order to calculate the average path derating factor, the path rating of each existing transmission path in WECC (WECC, 2013) is compared to the sum of thermal MVA ratings of transmission lines included in the path (FERC, 2012; Ventyx, 2012). The capacity-weighted average path derating factor for AC transmission paths is 0.59 (Figure A-3), whereas for DC transmission paths, this factor is 0.91.

Figure A-3: Histogram of AC transmission path derating factors in WECC



The path derating factor is calculated as the ratio of transmission path rating to the sum of the thermal MVA capacity of the individual lines that make up the transmission path. The two occurrences greater than 1.0 indicate small differences in the three datasets combined to create this analysis.

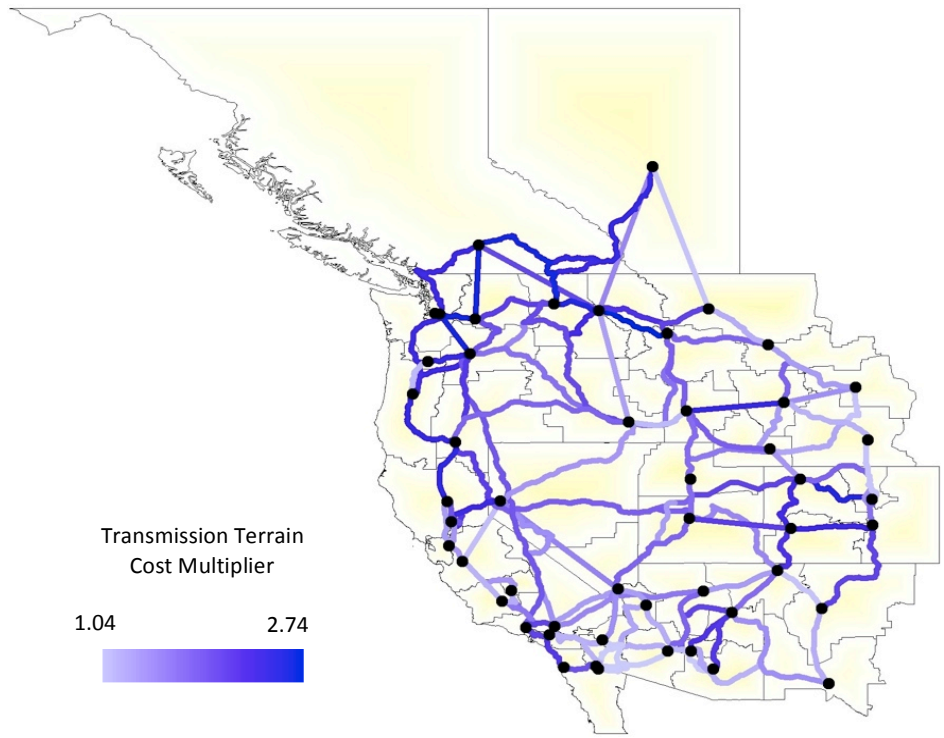
A.2.3 TRANSMISSION COST AND TERRAIN MULTIPLIER

The cost to build a transmission line depends on the terrain through which it passes. Expensive terrain types such as mountainous or urban terrain tend to be avoided in transmission planning, whereas less expensive flat or desert terrain types tend to be preferred. To capture the dependence of transmission cost on terrain type, Geographic Information Systems (GIS) analysis is used to overlay transmission paths with a terrain cost surface. Terrain-dependent cost multipliers (Mason, Curry, & Wilson, 2012; Western Governors' Association, 2009) are derived by combining a 1x1 km slope raster dataset with a 1x1 km land cover raster dataset. The length of transmission line that crosses each raster grid cell is multiplied by the terrain-dependent cost of the raster grid cell and summed over the entire transmission line, and then normalized by the length of the transmission line. Calculated in this manner, the average terrain cost multiplier is 1.50 for existing transmission paths across WECC that are simulated in SWITCH.

If no transmission corridor currently exists between two load areas, then the terrain traversed by straight line between the largest capacity substations of the two load areas is used to

calculate the terrain multiplier. This method will likely overestimate the cost of building between two previously unconnected load areas because transmission planners devise routes for new transmission lines that go around obstacles. However, it is more difficult to site and approve new transmission paths than to build along existing paths, so the overestimate resulting from the straight-line assumption may in many cases be balanced by the lack of accounting for the difficulty of building new lines.

Figure A-4: Transmission terrain cost multiplier between pairs of load areas



The most costly routes on which to build are the ones with the highest value for the cost multiplier. The largest capacity substation in each load area is depicted by a black dot. The cost multipliers depicted here are not normalized by the factor of 1.50 described in this section.

The average terrain cost multiplier of 1.50 is assumed to correspond to the average cost for building new high voltage transmission. An average high voltage transmission cost of \$1130 $MW^{-1}km^{-1}$ (\$2013) is adopted by default based on a range of values found in the Western Renewable Energy Zones (WREZ) transmission model (Western Governors' Association, 2009) for building new high voltage transmission lines in WECC. To calculate the total cost per MW of building transmission in SWITCH, the terrain cost multiplier of each new transmission path is first normalized by the average terrain cost multiplier for existing transmission (1.50). This value is the multiplied by three factors:

- The per unit transmission cost (\$1130 $MW^{-1}km^{-1}$)
- The transmission path length in km (generally the length along existing transmission lines)

- The average of the cost regionalization factors of the two load areas at the start and end of the transmission path (Section A.1.2: Cost Regionalization).

A.2.4 TRANSMISSION SUNK COSTS

The cost for maintaining the existing high voltage transmission is derived from the regional electricity tables of the United States Energy Information Administration's 2010 Annual Energy Outlook (EIA, 2010; EIA, 2011). The $/MWh cost incurred in 2010 for each NERC subregion is apportioned by present-day average load to each load area and the resultant annualized cost is assumed to be a sunk cost in every investment period in the study. All existing transmission capacity is therefore implicitly assumed to be kept operational indefinitely, incurring the associated operational costs.

A.3 DISTRIBUTION SYSTEM

We assume that the distribution network is built to serve the present-day peak demand, and that in future investment periods this equivalence must be maintained. By default, investment in new distribution capacity is therefore a sunk cost as projected loads are exogenously calculated. Sunk costs from existing distribution capacity are calculated in the same manner as sunk costs from existing transmission capacity (Section A.2.4: Transmission Sunk Costs). If demand response is enabled, then investment in new distribution capacity may take place to enable load shifting to peak demand hours. Such investment may be advantageous when peak demand hours coincide with hours of low net demand (demand minus variable renewable generation). For example, when large amounts of photovoltaic generation capacity is installed, demand response may shift demand from hours that have peak net demand just following sunset to hours early in the day.

Distribution losses are assumed to be 5.3% of end-use demand; commercial and residential distributed PV technologies are assumed to experience zero distribution losses as they are sited inside the distribution network. SWITCH does not currently support the export of power generated within the distribution system to the high voltage transmission system, rather any power generated within the distribution system must be either immediately consumed within the load area in which it is generated or curtailed. The only technologies currently modeled on the distribution side of the transmission system are residential and commercial photovoltaics. The lack of ability to export from the distribution system is not likely a driving factor in the results shown. Distributed generation is not installed in large amounts in most scenarios due to additional costs of distributed generation relative to similar centralized projects (Appendix A.10.1). The *12GW Distributed PV Scenario* represents an exception to this observation, as 12 GW of residential and commercial PV projects are installed by 2020 in California in this scenario. Even in this scenario the inability to export from the distribution network is unlikely to be important as in Figure 4-3 there is no observable curtailment of California electricity generation relative to the *Base Scenario*.

A.4 HISTORICAL DEMAND PROFILES

The amount of electricity demand in each hour simulated by SWITCH corresponds to demand on one historical hour. This equivalence ensures that the temporal profiles of wind and solar power output are properly matched to electricity demand, as correlations exist between demand and the output of wind and solar generators. In this study, the historical demand profile from 2006 is used as a base from which demand projections are created.

Planning Area hourly demand from the Federal Energy Regulatory Commission's (FERC) Annual Electric Balancing Authority Area and Planning Area Report (FERC, 2006) are partitioned into SWITCH load areas by matching substations owned by each planning area to georeferenced substations (Platts, 2009). A number of the SWITCH load areas represent a single planning area, so for these regions the planning area hourly demand is used as the demand of the corresponding load area. For planning areas that cross load area boundaries, the fraction of population within each load area is used to apportion planning area loads between SWITCH load areas.

A.5 DEMAND RESPONSE HOURLY POTENTIALS

To calculate hourly demand response potentials, we use hourly load data from obtained from the consulting firm 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 moveable in 2020, 2030, 2040, and 2050 (extrapolated linearly for years in between). The implicit assumption is that advanced metering infrastructure, installation of controllable appliances, and consumer education about demand response will increase the amount of demand response potential over time. The residential demand types we assume can be shifted include space heating and cooling, water heating, and dryers. Moveable commercial building demand types include space heating and cooling as well as water heating.

Table A-1: Fraction of demand that is moveable by end use and year for residential and commercial demand types.

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%

Based on the values in Table A-1, 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 areas to arrive at a total potential for moveable demand by hour. We assume this demand can be shifted to any other hour in the same day. Large-scale electrification of space and water heating is assumed to be occurring between present-day and 2050 and therefore the magnitude of heating demand is

increasing in addition to the percentage of devices available to provide demand response. Since demand data disaggregated by sector and end-use wasn't available for the rest of WECC, we used the overall fraction of total non-EV demand calculated to be moveable in California in each hour and applied that fraction to the hourly non-EV demand in each load area in the rest of WECC to calculate moveable demand availability. We assumed that moveable demand potential in the rest of WECC lags that in California by a decade.

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

Table A-2: Assumed battery charging times of the electric vehicle fleet.

Hours needed for full charge	Percent of total EV demand				
	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%

A.6 POLICIES, INITIATIVES, AND GOALS

A.6.1 CARBON CAP

The State of California has put into law a requirement to reduce GHG emissions to 1990 levels by 2020 with Assembly Bill 32 (CARB, 2013). In addition, Executive Order S-3-05 calls for a further decline in the state's emissions to 80% below 1990 levels by 2050. Our carbon cap scenarios assume that the rest of the WECC will have the same targets as California, possibly from national-level policy.

A.6.2 RENEWABLE PORTFOLIO STANDARDS

State-based Renewable Portfolio Standards (RPS) require that a fraction of electricity consumed within a Load Serving Entity (LSE) be produced by qualifying renewable generators. Targets follow a yearly schedule (DSIRE, 2011). For example, California has RPS targets of 20% and 33% by 2010 and 2020, respectively. RPS targets are subject to the political structure of each state and are therefore heterogeneous in not only what resources qualify as renewable, but also when, where and how the qualifying renewable power is made and delivered. To maintain computational feasibility, RPS is modeled as a yearly target for each load serving entity for the percentage of load that must be met by *delivered renewable* power. Delivered power is power that is either generated within a load-serving entity and consumed immediately, or imported to a load area via transmission. To ensure proper accounting, the stocks, flows, and consumption of qualifying power is kept separate from non-qualifying power.

In the version of SWITCH used in this study, renewable power is defined as power from geothermal, biomass solid, biomass liquid, biogas, solar or wind power plants. This is consistent with most of the state-specific definitions of qualifying resources in the western United States. Additionally, in most states, large hydroelectric power plants (> 50 MW) are not considered

renewable power plants due to their high environmental impacts. Small hydroelectric power plants (< 50 MW) do not qualify as renewable power in the current version of the model.

A.6.3 CALIFORNIA SOLAR INITIATIVE (CSI)

A number of programs collectively known as the "Go Solar California" programs (The California Solar Initiative, New Solar Homes Partnership, and various other programs), have set a goal of installing 3,000 MW of distributed solar capacity throughout the state of California by the year 2016 (CPUC, 2013). As these programs are well underway and are likely to reach their targets, we include a constraint in all optimizations that 3,000 MW of distributed solar photovoltaic capacity must be installed by 2016. The geographic distribution of this capacity will reflect the economic optimum from the perspective of the bulk power grid, and will not reflect the impacts of consumer preference or local incentives, which are often the most significant drivers of distributed renewable deployment.

A.6.4 CALIFORNIA DISTRIBUTED GENERATION MANDATE

California Governor Jerry Brown has set a goal of reaching 12,000 MW of distributed generation within the state of California by the year 2020 (Wiedman, Schroeder, & Beach, 2012). SWITCH does not enforce this goal by default, but we do explore one scenario in which 12,000 MW of distributed solar photovoltaic capacity must be installed by 2020 in California.

A.7 FUEL PRICES

Natural gas fuel price projections for electric power generation originate from the reference case of the United States Energy Information Administration's 2012 Annual Energy Outlook (AEO) (EIA, 2012). These yearly projections are made for each North American Electric Reliability Corporation (NERC) subregion through 2035, and are extrapolated for years after 2035. 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 (Wiser, Bolinger, & St. Clair, 2005), with consumption outside of WECC assumed as projected in the 2012 AEO. Regional price adders are determined by calculating the difference between the AEO 2012 projected regional prices and average wellhead price. Natural gas consumption data for all of Canada and Mexico is based on projections from the 2011 International Energy Outlook (IEO) (EIA, 2011) and then subdivided into regional consumption by province based on historical consumption data by province. Natural gas price data for Canada are based on the average border price forecast for natural gas from the AEO 2012. Natural gas price for Baja California Norte is assumed equal to the prices in the Southwest.

Coal and fuel oil prices are from the EIA AEO 2009 (EIA, 2009). The fuel price for each load area is set by the NERC subregion with the greatest overlap with that load area. Canadian and Mexican coal and fuel oil prices are assumed to be the same as the prices in the nearest United States NERC subregion. Coal and fuel oil price elasticity is not currently included.

Uranium price projections are taken from the California Energy Commission's 2007 Cost of Generation Model (CEC, 2007). These prices are applied to all load areas because regional price variation for uranium is negligible.

A.8 BIOMASS SOLID SUPPLY CURVE

Fuel costs for solid biomass are input into the SWITCH model as a piecewise linear supply curve for each load area. This piecewise linear supply curve is adjusted to include producer surplus from the solid biomass cost supply curve in order to represent market equilibrium of biomass prices in the electric power sector.

As no single data source is exhaustive in the types of biomass considered, solid biomass feedstock recovery costs and corresponding energy availability at each cost level originate from several sources listed in all calculations in this study.

Table A-3 below. This table represents the economically recoverable quantity of biomass solid feedstock, not the technical potential of recoverable solid biomass. The definition of 'economically recoverable' is dependent on each dataset, but the maximum cost is generally less than or equal to $100 per Bone Dry Ton (BDT) of biomass, with a small amount of biomass available at higher prices. Feedstock prices range between $0.2/MMBtu and $15.0/MMBtu (in $2013), with a quantity-weighted average cost across WECC of $3.1/MMBtu. Note that, following standard biomass unit definitions, 1 MMBtu = 10^6 Btu. Feedstock-specific conversion factors for the energy content per BDT of biomass are used for all calculations in this study.

Table A-3: Biomass supply in the SWITCH model for year 2030

Biomass Feedstock Type	California Availability [10^{12} Btu/Yr]	Rest of WECC Availability [10^{12} Btu/Yr]	Sources
Corn Stover	19.1	82.3	1
Forest Residue	41.3	408.8	1, 4
Forest Thinning	72.3	211.0	1
Mill Residue + Pulpwood	39.5	254.3	2, 3, 4
Municipal Solid Waste (MSW)	81.4	117.1	2, 4
Orchard and Vineyard Waste	66.1	10.5	2
Switchgrass	0	123.7	1, 4
Wheat Straw	8.1	70.0	1
Agricultural Residues (Canada Data Only)	0	183.2	4
Total	**327.8**	**1460.9**	

No change in biomass availability is assumed past 2030. Sources: 1: (de la Torre Ugarte & Ray, 2000; Tennessee, 2011); 2: (Parker, 2011); 3: (Milbrandt, 2005); 4: Canada Data Only (Kumarappan, Joshi, & MacLean, 2009). The conversion factor between BDT and MMBtu varies as a function of feedstock, but as a rule of thumb a factor of 15 MMBtu/BDT can be used for rough conversion between BDT and MMBtu.

A.9 EXISTING GENERATORS

A.9.1 EXISTING GENERATOR DATA

Existing generators within the United States portion of WECC are geolocated and assigned to SWITCH load areas using Ventyx EV Energy Map (Ventyx, 2009). The existing generator fleet includes generators installed through 2009 and therefore does not include additions or

retirements past 2009. Generators found in the United States Energy Information Administration's Annual Electric Generator Report (EIA, 2007) but not in the Ventyx EV Energy Map database, are geolocated by ZIP code. Canadian and Mexican generators are included using data in WECC's Transmission Expansion Planning Policy Committee database of generators (WECC, 2009). Generators with the primary fuel of coal, natural gas, fuel oil, nuclear, water (hydroelectric, including pumped storage), geothermal, biomass solid, biomass liquid, biogas and wind are included. Existing solar thermal and solar photovoltaic generators, as well as biomass cofiring units on existing coal plants are not included in the current version of the model. These generators represent a small fraction of existing capacity, and their exclusion does not significantly impact our results.

Existing generators are assumed to use the fuel with which they generated the most electricity in 2007 as reported in the United States Energy Information Administration's Form 906 (EIA, 2007). Generator-specific heat rates are derived by dividing each generator's fuel consumption by its total electricity output in 2007. Canadian and Mexican plants are assigned the heat rates given to their technology class (WECC, 2009), except for cogeneration plants, which are assigned the average heat rate for United Stated generators with the same fuel and prime mover.

Capital and operating costs for existing hydroelectric generators originate from present-day costs found in the United States Energy Information Administration's Updated Capital Cost Estimates for Electricity Generation Plants (EIA, 2010). Costs for existing non-hydroelectric generators originate from a recent Black and Veatch report (Black and Veatch, 2012). Generator lifetimes and construction schedules originate from the California Energy Commission's cost of generation model (CEC, 2010). To reflect shared infrastructure costs, cogeneration plants are assumed to have 75% of the capital cost of pure electric plants. Capital costs of existing plants are included as sunk costs and therefore do not influence decision variables.

With the exception of hydroelectric and nuclear technologies, existing plants are not allowed to operate past their expected lifetime (existing plant expected lifetimes are the same as for new plants – Table A-5). Cogeneration and geothermal existing plants are given the option to be reinstalled after their expected lifetime, at costs commensurate with the year of reinstallation. Existing plants scheduled for compliance with California's once-through cooling regulation are retired by the required compliance year (Cal/EPA, 2011) with the exception of the Diablo Canyon Power Plant. The two nuclear power plants, Diablo Canyon Power Plant and Columbia Generating Station, are assumed to have an operational lifetime of 60 years (a single relicensing) and therefore are retired before 2050. Palo Verde Nuclear Generating Station is assumed to be operational through 2050 due to its pivotal importance in the WECC power system. The San Onofre Nuclear Generating Station has been retired in this study.

In order to reduce the number of decision variables, non-hydroelectric generators are aggregated by prime mover for each plant and hydroelectric generators are aggregated by load area.

A.9.2 EXISTING HYDROELECTRIC AND PUMPED HYDROELECTRIC PLANTS

In any day simulated by SWITCH, hydroelectric generators without pumped storage are constrained to generate at an average historical monthly capacity factor derived from the years 2004-2011. For non-pumped hydroelectric generators in the United States, monthly net generation data originates from the United States Energy Information Administration's Form 923 and Form 906 (EIA, 2011). For non-pumped hydroelectric generators in the Canadian provinces of British Columbia and Alberta, monthly net generation data originates from Statistics Canada Tables 127-0001 and 127-0002 (Statistics Canada, 2008; Statistics Canada, 2012). For pumped hydroelectric generators, the use of net generation data is not sufficient, as net generation takes into account both electricity generated from in-stream flows and efficiency losses from the pumping process. The total electricity input to each pumped hydroelectric generator (EIA, 2011) is used to correct this factor. By assuming a 74% round-trip efficiency (Electricity Storage Association, 2011) and monthly in-stream flows for pumped hydroelectric projects similar to those from non-pumped projects, the monthly in-stream flow for pumped projects is derived. No pumped hydroelectric plants currently exist in Canadian or Mexican WECC territory (Ventyx, 2012).

Hydroelectric and pumped hydroelectric generators are aggregated to the load area level in order to reduce the number of decision variables in the model formulation. New hydroelectric facilities are not built in the current version of the model.

A.9.3 EXISTING WIND PLANTS

Hourly existing wind farm power output is derived from the 3TIER Western Wind and Solar Integration Study (WWSIS) wind speed dataset (3TIER, 2010; GE Energy, 2010) using idealized turbine power output curves on interpolated wind speed values. The total existing capacity, number of turbines, and installation year of each wind farm in WECC is obtained from the American Wind Energy Association (AWEA) wind plant dataset (AWEA, 2010). A total of 10 GW of existing wind farm capacity in the United States portion of WECC is input into SWITCH. Wind farms are geolocated by matching wind farms in the AWEA dataset with wind farms in the Ventyx EV Energy Map dataset (Ventyx, 2012).

Historical production from existing wind farms could not be used as many of these wind projects began operation after the historical study year of 2006. In addition, historical output would include forced outages, a phenomenon that is factored out of hourly power output in SWITCH. In order to calculate hourly capacity factors for existing wind farms, the rated capacity of each wind turbine is used to find the turbine hub height and rotor diameter using averages by rated capacity (The Wind Power, 2010). Wind speeds are interpolated from wind points found in the 3TIER wind dataset (3TIER, 2010) to the wind farm location using an inverse distance-weighted interpolation. The resultant speeds are scaled to turbine hub height using a friction coefficient of 1/7 (Masters, 2005). These wind speeds are put through an ideal turbine power output curve (Westergaard, 2009) to generate the hourly power output for each wind farm in the WECC.

Existing Canadian wind power output is calculated in similar manner to United States existing wind, using data from the Canadian Wind Energy Association (CANWEA, 2012) on wind turbine type and power capacity. AWS Truepower hourly wind speed data for a number of sites across Canada is scaled to existing turbine hub height. Hourly power output is calculated using turbine power curves for existing wind turbine generators. In total, 248 MW and 885 MW of existing wind are included for British Columbia and Alberta respectively.

A.10 NEW GENERATORS AND STORAGE

A.10.1 CAPITAL AND O&M COSTS

Costs for most technologies are assumed to stay constant in real terms through 2050 as these technologies are considered mature. Technologies that are assumed to decline in costs over time include solar, offshore wind, and battery storage. Capital costs and operation and maintenance (O&M) costs for each new power plant type originate primarily from Black and Veatch projections (Black and Veatch, 2012). Capital costs for compressed air energy storage in WECC are assumed to be higher than those in the Black and Veatch projections due to less favorable geology in WECC relative to other parts of the United States. Costs for biogas originate from a recent Electric Power Research Institute (EPRI) report (McGowin, 2007).

To reflect shared infrastructure costs, cogeneration projects are assumed to have 75 % of the capital and fixed O&M costs of a non-cogeneration project with the same prime mover and fuel. Variable O&M costs for cogeneration projects are assumed to be the same as for a non-cogeneration project with the same prime mover and fuel.

The costs shown in Table A-4 are used in all scenarios and for all generator and storage types, except for solar costs in the *Sunshot Solar Scenario*, which will be discussed elsewhere.

Table A-4: Generator and storage costs, in real $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
Bio Solid	Biomass IGCC	4.02	100000	15.8
Bio Solid CCS	Biomass IGCC CCS	6.75	114000	22.7
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	Compressed Air Energy Storage	1.24	12000	1.6
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
Storage	Battery Storage (2020)	3.98	26000	0
Storage	Battery Storage (2030)	3.77	26000	0
Storage	Battery Storage (2040)	3.56	26000	0
Storage	Battery Storage (2050)	3.35	26000	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

For consistency, the costs shown do not include expenses related to project development such as interest during construction, connection costs to the grid, upgrades to the local grid, and regional cost multipliers, though these costs are included in each optimization.

A.10.2 NEW GENERATOR AND STORAGE PROJECT PARAMETERS

Generator lifetimes and construction schedules originate from the California Energy Commission's cost of generation model (CEC, 2010). Heat rates, forced outage rates, and scheduled outage rates originate from Black and Veatch, 2012b, except for biogas (McGowin, 2007). All thermal technologies in SWITCH have the same heat rate throughout all investment periods. New cogeneration projects that replace existing projects are assumed to have the same electrical and thermal efficiencies as reported in (EIA, 2007).

Table A-5: New generator and storage project parameters

Fuel	Technology	Heat Rate (MMBtu/ MWh)	Thermal Efficiency, Net (%)	Construction Time (Yr)	Lifetime (Yr)	Forced Outage Rate (%)	Scheduled Outage Rate (%)	Carbon Emissions (tCO_2/MWh)
Bio Gas	Bio Gas	13.5	25.3	1	20	11	4	0
Bio Solid	Biomass IGCC	12.5	27.3	2	40	9	7.6	0
Bio Solid CCS	Biomass IGCC CCS	16.3	20.9	2	40	9	7.6	-1.309
Coal	Coal IGCC	7.9	42.9	2	40	8	12	0.759
Coal	Coal Steam Turbine	9.0	37.9	2	40	6	10	0.860
Coal CCS	Coal IGCC CCS	10.4	32.9	2	40	8	12	0.149
Coal CCS	Coal Steam Turbine CCS	12.1	28.2	2	40	6	10	0.173
Gas	CCGT	6.7	50.9	2	20	4	6	0.356
Gas	Compressed Air Energy Storage	4.9	69.5*	6	30	3	4	0.261
Gas	Gas Combustion Turbine	10.4	32.8	2	20	3	5	0.551
Gas CCS	CCGT CCS	10.1	33.9	2	20	4	6	0.080
Geothermal	Geothermal	-	-	3	30	0.7	2.4	0
Solar	Central PV	-	-	1	20	0	2	0
Solar	Commercial PV	-	-	1	20	0	2	0
Solar	CSP Trough 6h Storage	-	-	1	20	6	0	0
Solar	CSP Trough No Storage	-	-	1	20	6	0	0
Solar	Residential PV	-	-	1	20	0	2	0
Storage	Battery Storage	-	-	3	10	2	0.5	0
Uranium	Nuclear	9.7	35.1	6	40	4	6	0
Wind	Offshore Wind	-	-	2	30	5	0.6	0
Wind	Wind	-	-	2	30	5	0.6	0

*Projects with CCS are assumed to capture 85% of the carbon content of the input fuel. *The efficiency of compressed air energy storage quoted here contains only the natural gas portion of electricity generation – energy from compressed air in the storage cavern is also needed, lowering the total efficiency.*

A.10.3 CONNECTION COSTS

The cost to connect new generators to the existing electricity grid is derived from the United States Energy Information Administration's 2007 Annual Electric Generator Report (EIA, 2007).

Table A-6: Connection cost types in SWITCH

Connection Category	*Generic*	*Site-Specific*	*Distributed*
Connection Cost	*$103,200/MW ($2013)*	*$74,200/MW ($2013)* *Substation Cost* *+ Additional Distance-Specific* *Transmission Costs*	*$0/MW ($2013)* *(interconnection included In capital cost)*
Technologies	▪ Nuclear ▪ Gas Combined Cycle ▪ Gas Combustion Turbine ▪ Coal Steam Turbine ▪ Coal Integrated Gasification Combined Cycle ▪ Biomass Integrated Gasification Combined Cycle ▪ Biogas ▪ Battery Storage ▪ Compressed Air Energy Storage	▪ Wind ▪ Offshore Wind ▪ Central Station Photovoltaic ▪ Solar Thermal Trough, No Thermal Storage ▪ Solar Thermal Trough, 6h Thermal Storage ▪ Geothermal	▪ Residential Photovoltaic ▪ Commercial Photovoltaic

As these costs represent costs to connect a generator to the electricity grid, they are the same per unit of capacity for generation with or without cogeneration and/or carbon capture and sequestration.

The generic connection cost category applies to projects that are *not* sited at specific geographic locations. For these projects, the load area is the highest level of geographic resolution that we explore in SWITCH. For projects in generic connection cost category, it is assumed that it is possible to find a site near existing transmission in each load area, thereby not incurring significant costs to build new transmission lines to the grid. The average cost over the United States in 2007 (inflated to $2013) to connect generators to the grid without a large transmission line was $103,200 per MW (EIA, 2007). Substation installation or upgrade and grid enhancement costs that are incurred by adding the generator to the grid account for $74,200 per MW of the total connection cost. Constructing a small transmission line to the existing grid accounts for $29,000 per MW of the total connection cost.

The site-specific connection cost category applies to projects that *are* sited in specific geographic locations within SWITCH load areas but are not considered distributed generation. For these projects, the calculated cost to build a transmission line from the resource site to the nearest substation at or above 115 kV replaces the cost to build a small transmission line above. The cost to build this new line is $1,130 per MW per km, the same as to the assumed base cost of building transmission between load areas. Underwater transmission for offshore wind projects is assumed to be five times this cost, $5650 per MW per km. The load area of each site-specific project is determined through connection to the nearest substation, as the grid connection point represents the part of the grid into which these projects will inject power. At present, terrain cost multipliers are not included in the cost of connection to the transmission

grid, but as transmission lines for grid connection tend to be relatively short, the effect of this exclusion is likely to be minor.

The distributed connection cost category currently applies only to residential and commercial photovoltaic projects. For these projects, interconnection costs are included in project capital costs and are therefore given a cost of $0/MW here.

The connection cost of existing generators is assumed to be included in the capital costs of each existing plant.

A.10.4 NON-RENEWABLE THERMAL GENERATORS

A.10.4.1 NON-RENEWABLE THERMAL GENERATORS WITHOUT CCS

Nuclear steam turbines are modeled as baseload technologies. Their output remains constant in every study hour, de-rated by their forced and scheduled outage rates. Coal steam turbines and coal integrated gasification combined cycle plants (Coal IGCC) can vary output daily subject to minimum loading constraints, incurring heat rate penalties when operating below full load. These technologies are assumed to be buildable in any load area, with the exception of California load areas due to legal build restrictions on new nuclear and coal generation in California.

Natural gas combined cycle plants (CCGTs) and combustion turbines are modeled as dispatchable technologies and can vary output hourly. CCGTs incur costs and emission penalties when new capacity is started up and heat rate penalties when operating below full load. Combustion turbines incur startup costs and emissions when new capacity is started up. The optimization chooses how much to dispatch from these generators in each study hour, limited by their installed capacity and de-rated by their forced outage rate.

Cogeneration existing plants are given the option to be reinstalled after their expected lifetime, at costs commensurate with the year of reinstallation.

A.10.4.2 NON-RENEWABLE THERMAL GENERATORS WITH CCS

Generators equipped with carbon capture and sequestration (CCS) equipment are modeled similarly to their non-CCS counterparts, but with higher capital costs, fixed O&M costs, variable O&M costs, and heat rates (lower power conversion efficiencies). Projects with CCS are assumed to capture 85% of the carbon content of the input fuel. Newly installable non-renewable CCS technologies include gas combined cycle, coal steam turbine, and coal integrated gasification combined cycle. Cost data for these technologies originate from a recent Black and Veatch report (Black and Veatch, 2012).

All existing non-renewable cogeneration plants are given the option to replace the existing plant's turbine at the end of the turbine's operational lifetime with a new turbine of the same type equipped with CCS. As is the case with non-CCS cogeneration technologies, CCS cogeneration plants incur 75% of the capital cost of non-cogeneration plants to reflect shared infrastructure costs. Variable O&M costs for CCS generators increase relative to their non-CCS

counterparts from costs incurred during O&M of the CCS equipment itself, as well as costs incurred from the decrease in efficiency of CCS power plants relative to non-CCS plants.

Large-scale deployment of CCS pipelines would require large interconnected pipeline networks from CO_2 sources to CO_2 sinks. While the cost to construct a short pipeline is typically included in cost estimates, CCS generators that are not near a CO_2 sink would be forced to build longer pipelines, thereby incurring extra capital cost. If a load area does not contain an adequate CO_2 sink (NETL, 2008) within its boundaries, a pipeline between the largest substation in that load area and the nearest CO_2 sink is built, incurring costs consistent with literature values (Middleton & Bielicki, 2009).

CCS technology is in its infancy, with a handful of demonstration projects completed to date. This technology is therefore not allowed to be installed in the 2016-2025 investment period, as gigawatt scale deployment would not be feasible in this time frame. Starting in 2026, CCS generation can be installed in unlimited quantities.

A.10.5 COMPRESSED AIR ENERGY STORAGE

Conventional gas turbines expend much of their gross energy compressing the air/fuel mixture for the turbine intake. Compressed air energy storage (CAES) works in conjunction with a gas turbine, using underground reservoirs to store compressed air for the intake. During off-peak hours, CAES uses electricity from the grid to compress air into the underground reservoir. During peak hours, CAES adds natural gas to the compressed air and releases the mixture into the intake of a gas turbine. A storage efficiency of 81.7 % for CAES is used, in concert with a round trip efficiency of 1.4 (Succar & Williams, 2008) to apportion power output between generation and storage, as both natural gas and electricity from the grid energy stored in the form of compressed air are used to produce power from CAES plants. In addition, a compressor to expander ratio of 1.2 (Greenblatt, Succar, Denkenberger, Williams, & Socolow, 2007) is assumed.

CAES projects in WECC are assumed to be sited in aquifer geology. Geospatial aquifer layers are obtained from the United States Geological Survey (USGS, 2003) and all sandstone, carbonate, igneous, metamorphic, and unconsolidated sand and gravel aquifers are included (EPRI-DOE, 2003; Succar & Williams, 2008; Lu, Weimar, Makarov, Ma, & Viswanathan, 2009). A density of 83 MW/km^2 is assumed (Succar & Williams, 2008), resulting in very large CAES potential in almost all load areas. Local geological conditions may further restrict the amount of available capacity for CAES, but it is likely that substantial CAES potential exists in many areas throughout WECC.

A.10.6 BATTERY STORAGE

Sodium sulfur (NaS) batteries are available for construction in all load areas and investment periods. An AC-DC-AC storage efficiency of 76.7 % is assumed. SWITCH allows 100% depth of discharge, so we take a battery life of 3142 cycles (Lu, Weimar, Makarov, Ma, & Viswanathan, 2009). Assuming frequent utilization, we calculate a battery lifetime of 10 years (3142 cycles / (10 yr * 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. Battery capital and fixed O&M costs are from a recent Black and Veatch report (Black and Veatch, 2012). Note that this report includes the cost of battery replacement in their variable O&M cost and we therefore do not adopt their variable O&M value.

A.10.7 GEOTHERMAL

New sites for geothermal power projects are compiled from two separate datasets of geothermal projects under consideration from power plant developers (Western Governors' Association, 2009; Ventyx, 2009). The larger potential capacity of projects appearing in both datasets is taken. As new geothermal projects are located at specific sites within a load area, they incur the cost of building a transmission line to the existing electricity grid rather than a generic connection cost. These projects represent 7 GW of new geothermal capacity potential. Existing geothermal sites can be redeveloped after their expected lifetime using future cost values equal to that of new geothermal projects.

A.10.8 BIOGAS AND BIOLIQUID

County-level biogas availability (Milbrandt, 2005) is divided into load areas by land area overlap between each load area and county. This resource includes landfill gas, methane from wastewater treatment plants and methane from manure. Canadian and Mexican biogas resource potentials are scaled from United States potentials by population and Gross Domestic Product (GDP). Biogas plants are not sited in specific geographic locations within each load area and therefore incur the generic grid connection cost. It is assumed that new biogas plants will use combustion turbine technology. Existing biogas facilities that include cogeneration can be replaced at the end of their lifetime.

No new bioliquid plants are built, but existing bioliquid facilities can be replaced at the end of their lifetime.

A.10.9 BIOMASS SOLID

New biomass solid generation is not allowed to be built by default in this study, as it is assumed that all available solid biomass will be directed towards liquid biofuels for the transportation sector. Existing solid biomass plants are allowed to continue operation until the end of their operational lifetime. The resource potential and concomitant costs of biomass solid are as in *Section A.8:* Biomass Solid Supply Curve.

In two of the electricity scenarios in this study, we explore scenarios in which the electricity sector is allowed to build new generation units that consume solid biomass fuel to generate electricity. New biomass solid plants are assumed to use integrated gasification combined cycle (IGCC) technology. The option to include carbon capture and sequestration (CCS) technology for these biomass solid IGCC plants is included. While cost estimates exist for biomass solid IGCC plants in the capital and operating cost datasets that are utilized in this study (Section A.10.1: Capital and O&M Costs), these datasets do not include similar values for biomass solid IGCC CCS plants. As assumptions between cost datasets can differ substantially, we choose to estimate cost and efficiency parameters for biomass solid IGCC CCS plants from other similar

plant types. To estimate the capital cost of CCS equipment, we assume that the capital and fixed costs for adding a CCS system to a biomass solid IGCC plant are the same (in $/W of capacity) as for coal IGCC relative to coal IGCC CCS. To estimate the efficiency penalty of performing CCS – input energy is necessary to sequester carbon – we assume that the heat rate of a biomass solid IGCC plant increases by the same percentage when sequestering carbon as does coal IGCC relative to coal IGCC CCS. To estimate the increase in non-fuel variable operations and maintenance costs incurred by operating a CCS system on a biomass solid IGCC plant, we add a variable cost for sequestering carbon of $6.2/MWh to the biomass solid IGCC variable cost, which was calculated using the heat rate increase due to carbon sequestration of both coal and biomass IGCC plants.

A.10.10 WIND AND OFFSHORE WIND RESOURCES

A.10.10.1 UNITED STATES WIND

Hourly wind turbine output is obtained from the 3TIER wind power output dataset produced for the Western Wind and Solar Integration Study (WWSIS) (3TIER, 2010). 3TIER models the historical 10-minute power output from Vestas V-90 3 MW turbines in a 2-km by 2-km grid cells across the western United States over the years 2004-2006 using the Weather Research and Forecasting (WRF) mesoscale weather model. Each of these grid cells contains ten turbines, so each grid cell represents 30 MW of potential wind capacity. The Vestas V-90 3 MW turbine has a 100 m hub height.

Grid cells were selected by 3TIER using the following criteria:

1. Wind projects that already exist or are under development
2. Sites with the high wind energy density at 100 m within 80 km of existing or planned transmission networks
3. Sites with a high degree of temporal correlation to load profiles near the grid point
4. Sites with the highest wind energy density at 100 m (irrespective of location)

All of the grid cells in the 3TIER dataset (> 30,000) within WECC are aggregated into 3,311 onshore and 48 offshore wind farms. Many of the grid cells are very near each other; adjacent wind points are aggregated if their area is within the corner-to-corner distance of each other, 2.8 km. Wind points with standard deviations in their average SCORE-lite power output greater than 3 MW are aggregated into different wind farms. Offshore and onshore wind points are aggregated separately. The 10-minute SCORE-lite power output for each wind point is averaged over the hour before each timestamp, and then these hourly averages are again averaged over each group of aggregated grid cells to create the hourly output of 3,311 onshore (875 GW) and 48 offshore (6 GW) wind farms. The onshore wind farms are then put through the site selection process (Section A.10.12: Site Selection of Variable Renewable Projects), resulting in 1,527 sites with 466 GW of potential capacity.

A.10.10.2 CANADIAN WIND

A 2x2 km raster GIS layer of average wind speed at 80 m hub height from AWS Truepower is used both to select wind projects and to quantify the potential wind power capacity of each project. Land not suitable for wind development is removed by excluding sites with low average wind speeds, slope over 10%, forested areas, and exclude/avoid areas from the Western Renewable Energy Zones (WREZ) study (Western Governors' Association, 2009). After site selection, British Columbia has 20 sites with a total of 10.6 GW of potential onshore wind turbine capacity, and Alberta has 21 sites with a total of 74.3 GW of onshore potential wind turbine capacity. Canadian offshore wind is not modeled in this study.

Historical hourly wind speed data originates from AWS Truepower for the Canadian provinces of British Columbia and Alberta for the wind sites discussed above. Hourly turbine power output is calculated by using a Vestas V-90 3 MW wind turbine power curve and AWS Truepower wind speed data at 80 m hub height.

A.10.11 SOLAR RESOURCES

In this study we model five different solar technologies, each with different output characteristics, resource availability, and costs. Concentrating Solar Power (CSP) is used here as a synonym for solar thermal power.

1. Residential PV - south-facing fixed photovoltaics mounted on residential rooftops, connected to the distribution grid
2. Commercial PV - south-facing fixed photovoltaics mounted on commercial rooftops, connected to the distribution grid
3. Central PV – 1-axis tracking photovoltaics cited on available rural land, connected to the transmission grid
4. CSP Trough No Storage – dry-cooled solar thermal trough systems lacking thermal energy storage cited on available rural land, connected to the transmission grid
5. CSP Trough 6h Storage – dry-cooled solar thermal trough systems with 6 hours of thermal energy storage cited on available rural land, connected to the transmission grid

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 from the National Renewable Energy Laboratory (NREL, 2013). Hourly weather input data from 2006 is obtained from the National Renewable Energy Laboratory's Solar Prospector dataset (NREL, 2013). The Solar Prospector dataset has 10x10 km resolution across the entire United States.

A.10.11.1 DISTRIBUTED PHOTOVOLTAICS – RESIDENTIAL AND COMMERCIAL

Residential and commercial PV sites are created overlaying a raster GIS layer of population density with the 10x10 km Solar Prospector grid cells. Any grid cell with a total projected population greater than 10,000 in the year 2015 is included in the set of distributed PV sites modeled in SWITCH. Grid cells were aggregated to distributed PV sites by joining adjacent grid cells. When calculating hourly capacity factors for each distributed PV site, the population-weighted average of hourly capacity factor is used as the output of the site. Solar Prospector

data currently only spans the United States, so Mexican and Canadian cities in WECC with a population greater than 10,000 are assumed to have the insolation and weather conditions of the nearest Solar Prospector grid cell. In total, 216 distributed PV sites are modeled, each with separate hourly output profiles for residential and commercial PV (432 total output profiles).

The roof area available for distributed photovoltaic development is estimated based on Navigant (Chaudhari, Frantzis, & Hoff, 2004) and NREL (Denholm & Margolis, 2007) reports. Projected state-level roof area data for the year 2025 (Chaudhari, Frantzis, & Hoff, 2004) is apportioned to distributed PV sites by population. We assume 20% of all residential and 60% of all commercial roof area to be available for development. The rooftop spacing ratio for commercial PV is derived from the Department of Defense Unified Facilities Criteria (DOD, 2002). Canadian rooftop availability per capita is assumed to be equal to the US average rooftop availability per capita. Mexican rooftop availability is scaled by GDP from average US values. In total, 125 GW of residential and 53 GW of commercial PV are included across WECC.

In SAM, residential, and commercial PV systems are simulated as 270 W_{DC} multi-crystalline silicon Suntech STP270-24-Vb-1 modules using the California Energy Commission module model. Both technologies are modeled as southward facing, not shaded, and tilted at an angle equal to the latitude of the simulated grid cell. Residential PV systems are simulated with the 270 W_{DC} modules connected in a 9-module string to make a 2.4 kW_{DC} array and are coupled with a 2.5 kW_{AC} SMA Solar Technology SB2500HFUS-30-208V inverter. Derating factors for soiling (95 %), pre-inverter (96 %), and post-inverter (98 %) are included. Commercial photovoltaic systems are simulated as a 250 kW_{DC} array and are coupled with a 250 kW_{AC} SMA America SC250U (480V) inverter. Derating factors for soiling (98 %), pre-inverter (96 %), and post-inverter (98 %) are included.

A.10.11.2 CENTRAL STATION SOLAR – PHOTOVOLTAICS (PV) AND CONCENTRATING SOLAR POWER (CSP)

Land suitable for large-scale solar development is derived using land exclusion criteria from (Mehos & Perez, 2005). Types of land excluded are: national parks, national monuments, wildlife refuges, military land, urban areas, land with greater than 1% slope (at 1 km resolution), and parcels of land smaller than 1 km^2. In addition, only areas with land cover of wooded and non-wooded grassland, closed and open shrubland, and bare ground are assumed to be available for solar development. The minimum insolation cutoff from (Mehos & Perez, 2005) is not used because the potential for low cost solar in the future might make central station solar viable in areas with only moderate insolation.

The available land for solar is aggregated on the basis of average Direct Normal Insolation (DNI) for both CSP and central station PV. To create the final solar farms, an iterative procedure is employed that partitions available solar land polygons with standard deviations of DNI greater than 0.12 kWh/m^2/day into smaller polygons. Note that photovoltaics can utilize diffuse radiation in addition to direct normal radiation, but for the purposes of creating available land for central station solar, we ignore this difference. In the final power output calculations described below, diffuse and direct insolation is handled correctly for each technology via the System Advisor Model (SAM).

In SAM, central station PV is modeled single-axis tracking 100 MW_{DC} array using the Suntech 270 W_{DC} panels discussed above. The array is connected to an Advanced Energy Solaron 500HE (3159502-XXXX) 408V inverter with 500 kW_{AC} capacity. The tracker is tilted at an angle equal to the latitude of the simulated grid cell, with a row width of 3 m and space between adjacent rows of 3 m. Backtracking is enabled. Derating factors for soiling (98 %), pre-inverter (94 %), and post-inverter (98 %) are included. A total of 10.9 TW of central station photovoltaic systems are simulated. After site selection (Section A.10.12: Site Selection of Variable Renewable Projects) this is reduced to 3.3 TW.

100 MW nameplate CSP systems with and without thermal storage are modeled in SAM using the 'CSP Trough Physical' model for parabolic trough systems. Solargenix SGX-1 collectors and Schott PTR70 receivers are used, and natural gas backup is not included. A solar multiple of 1.4 is assumed for systems without thermal storage and a solar multiple of 2.0 is assumed for systems with thermal storage. The irradiation at design is set using Typical Direct Year (TDY) from the Solar Prospector dataset. An air-cooled cooling system is modeled in order to minimize water consumption, as many of these CSP systems would be installed in places with little or no water nearby.

For systems with thermal storage, 6 full load hours of storage is included using Hitec Solar Salt. In this study, dispatch of CSP thermal storage is embedded in the hourly capacity factors using a uniform dispatch schedule. On sunny days CSP storage is therefore typically dispatched from sunset through the early part of the night.

A total of 16.4 TW of CSP trough systems without storage are simulated. After site selection, this is reduced to 5.4 TW. A total of 11.5 TW of CSP trough systems with six hours of thermal storage are simulated. After site selection, this is reduced to 3.7 TW.

A.10.12 SITE SELECTION OF VARIABLE RENEWABLE PROJECTS

In an effort to reduce model runtime, the number of central station solar and onshore wind sites is reduced using criteria that retain the best quality resources, geographic diversity, and load-serving capability of each resource. All distributed photovoltaic and offshore wind sites are retained. There is enormous central station solar and onshore wind potential in WECC, and applying the following conditions does not substantially reduce the ability of these resources to meet demand.

1. All projects with capacity factors that are in at least the 75th percentile of the capacity-weighted average capacity factor for their technology are retained.
2. At least five of the highest average capacity factor projects of each technology type in each load area are retained.
3. Projects are retained such that the total available energy over the course of a year from all projects of a given technology type must be greater than or equal to three times the present-day demand in each load area. If a given technology type in a load area does have sufficient available energy to meet this restriction, then all projects of that technology type are retained.

APPENDIX B SWITCH INVESTMENT MODEL DESCRIPTION

B.1 STUDY YEARS, MONTHS, DATES AND HOURS

To simulate the dynamic evolution of the power system over the course of the next forty years, four levels of temporal resolution are employed by the SWITCH model: investment periods, months, days, and hours. Investment periods are the only level of temporal resolution in which SWITCH is able to modify the installed capacity of power system assets – generation plants, transmission lines, and storage facilities. In the other three levels of temporal resolution, power system assets must be operated within the installed capacities determined by investments made in each investment period. It is important to note that SWITCH simultaneously simulates all four levels of temporal resolution in order to capture the interdependencies between system dispatch and installed capacity of power system assets.

A single investment period contains historical data from 12 months, two days per month (the peak and median load days) and six hours per day. There are four ten-year long investment periods: 2016-2025, 2026-2035, 2036-2045, and 2046-2055 in each optimization, resulting in (4 investment periods) x (12 months/investment period) x (2 days/month) x (6 hours/day) = 576 study hours over which the system is dispatched. The middle of each period is assumed to be representative of conditions within that period, e.g. the year 2050 represents the period 2046-2055.

The days with peak hourly demand and median total demand from each historical month are sampled in order to characterize a large range of possible load and weather conditions over the course of each investment period. Each sampled day is assigned a weight: peak load days are given a weight of one day per month, while median days are given a weight of the number of days in a given month minus one. The purpose of this weighting scheme is threefold: 1) to ensure that the total number of days simulated in each investment period is equal to the number of days between the start and end of that investment period; 2) to emphasize the economics of dispatching the system under 'average' load conditions; and 3) to guarantee that sufficient capacity is available during times of high grid stress. Note that a larger set of sampled hours are explored in the post-investment dispatch check (B.7: Present-Day Dispatch), but will not be discussed further in this section.

To make the investment optimization computationally feasible, six distinct hours of load and resource data are sampled from each study date, spaced four hours apart. For peak days, hourly sampling is offset to ensure the peak hour is included. For median days, hourly sampling begins at 2 am Greenwich Mean Time (GMT) and includes hours 2, 6, 10, 14, 18, and 22. This median day sampling regime was chosen because it represents solar insolation conditions within WECC with the smallest difference between population and sample means of any four-hour spacing interval.

The output of renewable generators can be correlated not only across renewable sites but also with electricity demand as both are affected by weather conditions. A classic example of this type of correlation is the large magnitude of air conditioning load that is present on sunny, hot days. To account for these correlations in SWITCH, we employ time-synchronized historical

hourly load and generation profiles for locations across WECC. Each date in future investment periods corresponds to a distinct historical date from 2006, for which historical data on hourly loads and simulated hourly wind and solar capacity factors over the Western United States, Western Canada, and Baja California Norte are used. Historical hourly load data is scaled to projected future demand and shaped by implementation of energy efficiency, vehicle electrification, and heating electrification. Solar and wind resource availability is used directly from historical data. Hydroelectric average capacity factors are a function of month and are derived from historical average generation from the years 2004-2011.

B.2 SETS AND INDICES

SWITCH employs many levels of temporal, geographic, resource, and operational specificity when making investment decisions. Sets and their corresponding indices are a concise notational method for representing these levels of specificity, and will be used extensively in the following documentation.

Table B-1: Sets and indices

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*
A	*a*	load areas
TX	(*a,a'*) $a \in A, a' \in A$	transmission paths that connect load areas *a* and *a'*
LSE	*lse*	load-serving entities
BA	*ba*	balancing areas
F	*f*	fuels
$BF \subset F$	*bf*	biofuels
$R \subset F$	*r*	RPS-eligible fuels
DC	*dc*	demand category
P	*p*	all generation and storage projects
$GP \subset P$	*gp*	all generation projects
$GP_a \subset GP$	-	all generation projects in load area *a*
$GP_{cal} \subset GP$	-	all generation projects in California
$DP \subset P$	*dp*	dispatchable generation projects
$IP \subset P$	*ip*	intermediate generation projects
$FBP \subset P$	*fbp*	flexible baseload generation projects
$BP \subset P$	*bp*	baseload generation projects
$CBP \subset BP$	*cbp*	cogeneration projects (baseload)
$VP \subset P$	*vp*	variable renewable generation projects

Set	***Index***	***Description***
VDP⊂VP	*vdp*	variable renewable distributed generation projects
VCP⊂VP	*vcp*	variable renewable centralized generation projects
SP⊂P	*sp*	storage projects (pumped hydro, compressed air energy storage and battery storage)
SP_a⊂SP	-	storage projects in load area *a*
HP⊂P	*hp*	hydroelectric projects
PHP⊂S (also, PHP⊂HP)	*php*	pumped hydroelectric projects
BP⊂S	*bp*	battery storage projects
CP⊂S (also, CP⊂DP)	*cp*	compressed air energy storage projects
EP⊂P	*ep*	existing plants
RP⊂P	*rp*	RPS-eligible projects
CLP⊂P	*clp*	capacity-limited projects
LLP⊂P	*llp*	land area-limited projects
LOC	*loc*	locations over which land area-limited projects are constrained
BLP⊂P	*blp*	bio availability-limited projects

B.3 DECISION VARIABLES: CAPACITY INVESTMENT

The installation of physical ("in the ground") power systems infrastructure over time is controlled by the capacity investment decision variables in SWITCH. The capacity of each piece of physical infrastructure installed at each point in time and at different locations throughout WECC is dependent on both the cost to install and maintain the infrastructure (Section B.5: Objective Function and Economic Evaluation) and the way in which the infrastructure is utilized (Section B.4: Decision Variables: Dispatch).

<u>Capacity Investment Decision Variables:</u>

1. Amount of new generation or storage capacity to install of each generation or storage technology type in each load area in each investment period
2. Amount of transmission capacity to add between load areas in each investment period
3. Capacity at which to operate each thermal existing power plant in each investment period
4. Amount of distribution network capacity to install in each load area in each investment period

Table B-2: Investment decision variables

$G_{p,i}$	Generation or storage capacity to install at project *p* in investment period *i*
$E_{ep,i}$	Capacity at which to operate existing plant *ep* in investment period *i*
$T_{(a,a'),i}$	Transmission capacity to install between two load areas (*a,a'*) in investment period *i*
$D_{a,i}$	Distribution network capacity to install in load area *a* in investment period *i*

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 in this study.

New high-voltage transmission capacity is built along existing transmission corridors between the largest capacity substations of each load area. Transmission can be built between adjacent load areas, non-adjacent load areas with primary substations less than 300 km from one another, and non-adjacent load areas 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 area is included as a sunk cost equal to the cost of building the distribution system to meet projected peak demand. Consequently, by default, new distribution capacity does not have associated decision variables. However, if demand response is enabled, then investment in new distribution capacity may take place to enable load shifting onto peak demand hours. Such investment may be advantageous when peak demand hours coincide with hours of low net demand (demand minus variable renewable generation) such as 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.

B.4 DECISION VARIABLES: DISPATCH

The way in which physical power systems infrastructure is utilized is controlled by dispatch decision variables. Choices are made in every study hour or every study day about how to dispatch generation, storage, and transmission via the dispatch decision variables.

Dispatch Decision Variables:

1. Amount of energy to generate from each dispatchable and intermediate generation project (hydroelectric and non-cogeneration natural gas plants) in each hour.
2. Amount of capacity to commit to being online from each intermediate generation project (non-cogeneration combined cycle and steam turbine natural gas plants) in each hour.
3. 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.
4. Amount of energy to generate from each flexible baseload generation project (coal plants) each day.
5. Amount of energy to transfer along each transmission corridor in each hour.
6. 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.
7. If demand response is enabled, the amount of demand to shift from and to each hour.
8. Amount of renewable energy and associated certificates (RECs) to consume in each load serving entity in each hour.
9. Amount of non-distributed energy to consume in each load area in each hour, in both the load-satisfying and reserve margin dispatch schedule.

Dispatch 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. Dispatch decisions are also not made for variable renewable generators such as wind and solar. If the model chooses to install them, wind and solar 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 is allowed to occur in any hour and is assumed to be curtailed.

Most decision variables listed here represent decisions about how to operate physical power systems infrastructure. In contrast, the decision variables associated with the consumption of electricity and RECs represent a higher-level of decisions associated with activities of larger entities (such as load serving or balancing entities) in the power system. One can think of these consumption variables as 'bookkeeping' variables in that they do not directly represent physical infrastructure decisions. Rather, bookkeeping variables influence direct physical infrastructure decisions and are therefore of importance to power systems operation.

Table B-3: Dispatch decision variables

$O_{p,t}$	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*
$TR_{(a,a'),t}$	Energy transferred in hour *t* along the transmission path between two load areas (*a,a'*)
$S_{sp,t}$	Energy stored in hour *t* at storage project *sp*
$R_{sp,t}$	Energy released in hour *t* from storage project *sp*
$SR_{p,t}$	Spinning reserve provided by dispatchable or intermediate project *p* in hour *t* ($p \in DPUIP$)
$Q_{p,t}$	Quickstart reserve provided by project *p* in hour *t* ($p \in DPUIP$)
$OP_{p,t}$	Operating reserve (spinning and quickstart) provided by hydroelectric or storage plant *p* in hour *t* ($p \in HPUSP$)
$DR_{a,t}$	Shift load away from hour *t* in load area *a*
$MDR_{a,t}$	Meet shifted load in hour *t* in load area *a*
$REC_{lse,\ t}$	Renewable energy certificates consumed in load serving entity *lse* in hour *t*
$NP_{a,t}$	Non-distributed energy consumed in load-satisfying dispatch in load area *a* in hour *t*
$NPR_{a,t}$	Non-distributed energy consumed in reserve margin scheduling in load area *a* in hour *t*

B.4.1 TREATMENT OF OPERATING RESERVES

Operating reserves in the WECC are currently determined by the 'Regional Reliability Standard to Address the Operating Reserve Requirement of the Western Interconnection' (NERC, 2007). This standard dictates that contingency 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. In practice, this 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.

SWITCH's operating reserve requirement is based on the "3+5 rule" developed in the Western Wind and Solar Integration Study. This method for determining reserve requirements is considered "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 3Δσ requirement for net

load variability. For most conditions, a considerably higher amount of reserves were carried than necessary to meet the 3Δσ requirement. Performance did vary at the individual area level, so in the future customized reserve rules may be implemented for different areas. SWITCH's contingency reserve requirement is even more conservative, as quickstart reserves of 3 percent of load and 5 percent of variable renewable generation are also held.

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 37 balancing areas (Hunsaker, Samaan, Milligan, Guo, Liu, & Toolson, 2013), 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 areas 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 primary NERC sub-region as the balancing area in its optimization. Six balancing areas are modeled: Arizona-New Mexico, Rocky Mountain, California, Pacific Northwest, Canada, and Baja California Norte.

Currently, the model allows natural gas generators (including gas combustion turbines, combined-cycle natural gas plants, and stream turbine natural gas plants), hydro projects, and storage projects (including compressed air energy storage, NaS batteries, and pumped hydro) to provide spinning and non-spinning reserves. 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, which is calculated from the generator's part-load efficiency curve (London Economics and Global Energy Decisions, 2007). 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 as backing off too far from full load quickly becomes uneconomical. Hydro projects are limited to providing no more than 20 percent of their turbine capacity as spinning reserves, in recognition of water availability limitations and possible environmental constraints on their ramp rates.

B.5 OBJECTIVE FUNCTION AND ECONOMIC EVALUATION

The goal of SWITCH in this study is to minimize the present value of all costs incurred while running the power system from present-day to 2050. SWITCH must do so while satisfying a multitude of requirements of the power system: meeting projected demand, renewable portfolio standard goals, carbon goals, reliability requirements, etc. In the language of the constrained optimization framework used by SWITCH, the goal of the optimization is called the "objective function." The requirements, or "constraints" will be described in detail following a description of the objective function.

The decisions made by SWITCH can be thought of as those that would be made by a hypothetical WECC-wide electric power system planning agency whose goal is to deliver the lowest cost of electricity over the course of time for their entire planning region, while meeting a number of goals and standards. SWITCH therefore employs a discount rate that represents the return on societal investments over time, as made by either public or private actors. All costs during the study time frame are discounted to a present-day value using a real discount rate of 7%, so that costs incurred later in the study have less impact on the optimization than those incurred earlier. Consistent with the societal planning perspective taken by SWITCH, a real finance rate of 7% is also assumed throughout the study. The 7 % real value is within the range of normal Weighted Average Cost of Capital (WACC) values for regulated electric utilities. All costs are specified in real terms throughout this study, and are inflated to real $2013 using the Consumer Price Index (CPI).

Sensitivity studies investigated the impact of different discount rates on the build-out of power system capacity. In one set of studies, the discount rate was kept constant at 7 % and the finance rate was varied between 0 % and 10 %, thereby investigating how the cost of capital relative to the cost of fuel and maintenance would change grid infrastructure build-out. It was found that the optimal build-out changed greatly with finance rate. At lower finance rates, more capital-intensive projects were built, whereas at higher finance rates less capital-intensive projects were built. The second set of studies adjusted the discount and finance rates up and down from 0 % to 10 % together (discount rate = finance rate) to understand how the relative weighting of costs at different points in time would influence built-out. In these studies, very little difference in build-out was found between different rates, indicating that few trade-offs exist with respect to the timing of infrastructure build-out when considering minimal cost strategies across all time periods simultaneously. This makes sense in the context of a quickly decreasing cap on carbon emissions – the cap drives much of the infrastructure build-out over time, drastically reducing the number of tradeoffs that can be made between different time periods at minimal cost. The two discount/finance rate sensitivity studies together indicate that the generation, transmission, and storage infrastructure built in this study is relatively insensitive to the valuation of costs incurred at different points in time, but is sensitive to the cost of capital. As we believe that a 7 % real value for the cost of capital represents a reasonable expectation of future conditions, we did not perform further sensitivities and thus all optimizations in the results section have both a 7 % real discount and a 7 % real finance rate.

The objective function includes the following system costs:

1. Capital costs of existing and new power plants and storage projects
2. Fixed operations and maintenance (O&M) costs incurred by all active power plants and storage projects
3. Variable costs incurred by each plant, including variable O&M costs, fuel costs to produce electricity and provide spinning reserves, and any carbon costs of greenhouse gas emissions (carbon costs are not included in this study)
4. Capital costs of new and existing transmission lines and distribution infrastructure
5. Annual O&M costs of new and existing transmission lines and distribution infrastructure

Generator and storage capital and O&M costs are specified for each technology and each year and are primarily based on Black and Veatch and United States Energy Information Administration data (Black and Veatch, 2012; EIA, 2010). See Section A.10.1: Capital and O&M Costs for more detail. Capital costs are amortized over the expected lifetime of each generator or transmission line, and only those payments that occur during the length of the study are included in the objective function. For each project in the SWITCH optimization, capital costs are assumed to be as in the first year of construction. Construction costs are tallied yearly, discounted to present value at the online year of the project, and then amortized over the operational lifetime of the project. The cost to connect new power plants to the grid is assumed to be incurred in the year before operation begins.

Fuel prices are derived from a number of sources (Section A.7: Fuel Prices and Section A.8: Biomass Solid Supply Curve). Coal, oil, and nuclear fuel costs are modeled as invariant with the level of fuel consumption as the consumption of these fuels within WECC represents a small fraction of their total consumption. Natural gas and biomass solid fuel prices are allowed to vary with the level of consumption.

Transmission and distribution costs are discussed in Section A.2: High Voltage Transmission and Section A.3: Distribution System respectively.

Objective function: minimize the power system discounted present-day cost			
Generation and Storage	Capital	$\sum_{p,i} G_{p,i} \times c_{p,i}$	The capital cost incurred for installing capacity at generation or storage project *p* in investment period *i* is calculated as the generator or storage project size in MW ($G_{p,i}$) multiplied by the capital cost (including installation, grid connection, and interest during construction costs) of that type of generator or storage project in \$/MW ($c_{p,i}$).
Generation and Storage	Fixed O&M	$+\sum_{ep,i} E_{ep,i} \times fom_{ep,i}$ $+\sum_{p,i} G_{p,i} \times fom_{p,i}$	The fixed operation and maintenance costs paid for generation and storage projects are calculated as the sum of fixed O&M of each existing project in each investment period (the existing capacity ($E_{ep,i}$) online in investment period *i* at existing plant *ep* multiplied by the recurring fixed costs associated with that type of generator in \$/MW ($fom_{ep,i}$)) and the sum of fixed O&M for new projects (new capacity installed and online ($G_{p,i}$) through investment period *i* at project *p* multiplied by the recurring fixed costs associated with that type of generator in \$/MW ($fom_{p,i}$)).

	Variable	$+\sum_{p,t} O_{p,t}\times(vom_{p,t}+f_{p,t}+c_{p,t})\times hs_t$ $+\sum_{p\in \mathrm{DP}\cup\mathrm{IP},t} SR_{p,t}\times(spf_{p,t}+spc_{p,t})\times hs_t$ $+\sum_{p\in \mathrm{FBP}\cup\mathrm{IP},t} DC_{p,t}\times(dcf_{p,t}+dcc_{p,t})\times hs_t$	The variable costs paid for operating plant *p* in timepoint *t* are calculated as the power output in MWh ($O_{p,t}$) multiplied by the sum of the variable costs associated with that type of generator in \$/MWh. The variable costs include operations and maintenance ($vom_{p,t}$), fuel ($f_{p,t}$), and carbon cost ($c_{p,t}$) (not included in this study), and are weighted by the number of hours each timepoint represents (hs_t). Variable costs also include the fuel ($spf_{p,t}$) and carbon ($spc_{p,t}$) costs incurred by projects providing spinning reserves ($SR_{p,t}$). (only dispatchable and intermediate generation projects incur costs while providing spinning reserves) as well as fuel ($dcf_{p,t}$) and carbon ($dcc_{p,t}$) costs incurred when deep-cycling below full load. The amount below full load ($DC_{p,t}$) equals the committed capacity minus the actual power output of the intermediate or flexible baseload plant.
Transmission	Capital	$+\sum_{(a,a'),i} T_{(a,a'),i}\times l_{(a,a')}\times t_{(a,a'),i}$	The cost of building or upgrading transmission lines in the path between two load areas (*a,a'*) in investment period *i* is calculated as the product of the rated transfer capacity of the new lines in MW ($T_{(a,a'),i}$), the length of the path ($l_{(a,a')}$), and the area- and terrain-adjusted per-km cost of building new transmission in \$/MW·km ($t_{(a,a'),i}$).
	O&M	$+\sum_{(a,a'),i} T_{(a,a'),i}\times l_{(a,a')}\times fom_{(a,a'),i}$	The cost of maintaining new transmission lines in the path between two load areas (*a,a'*) in investment period *i* is calculated as the product of the rated transfer capacity of the new lines in MW ($T_{(a,a'),i}$) the length of the path ($l_{(a,a')}$) and the area- and terrain-adjusted per-km cost of maintaining new transmission in \$/MW·km ($fom_{(a,a'),i}$).

Distribution		$+\sum_{a,i} D_{a,i} \times d_{a,i}$	The cost of upgrading the distribution system within load area *a* in investment period *i* is calculated as the product of the new distribution capacity installed in MW ($D_{a,i}$) and the cost of building and maintaining the new capacity in \$/MW ($d_{a,i}$). Unless demand response is enabled, the new distribution capacity installed ($D_{a,i}$) is completely determined by the peak demand in load area *a* in investment period *i*.
Sunk		$+s$	Sunk costs (*s*) include capital payments for existing generation and storage plants, and capital and maintenance payments for existing transmission and distribution networks.

B.6 CONSTRAINTS

Limits imposed on the power system are mathematically described as constraints within the SWITCH model framework. It is the constraints of the SWITCH model that determine the context for least cost investment plans and as such the constraints are inseparable from the cost-minimization objective function itself. It can therefore be helpful when reading the description of each constraint to ask the question "How is this constraint satisfied at the least possible cost?," keeping in mind that least possible cost is defined in Section B.5: Objective Function and Economic Evaluation. One of the biggest strengths of using a linear program framework (the framework used by SWITCH) is that all constraints are satisfied in an interdependent manner, so the decision variables that appear in more than one constraint will be adjusted in the context of all other constraints in the model, as well as the objective function.

The model includes a few main sets of constraints:

1. Those that ensure that demand is satisfied
2. Those that maintain reserves for reliability purposes
3. Those that enforce public policy constraints (such as a cap on carbon emissions)
4. Those that enforce resource constraints for generation projects
5. Those that govern the installation of additional transmission and distribution capacity
6. Those that model the operational characteristics of generation and storage projects
7. Those that govern the dispatch of demand response

We choose to describe each constraint or set of constraints in three different but equivalent ways in order to facilitate reader comprehension of each constraint. At the start of each section we describe the constraint in words, excluding indices and variable definitions for

clarity. We then include on the left hand side of each box a mathematical definition of each constraint, and on the right hand side of each box a verbal definition of each constraint using indices and variables from the mathematical definition.

B.6.1 DEMAND-MEETING CONSTRAINTS

The demand-meeting constraints require generation, transmission, and storage infrastructure be dispatched in such a manner as to meet demand in every simulated hour in every load area. The nameplate capacity of grid assets is de-rated by their forced outage rate to represent the amount of generation, transmission, and storage capacity that is available on average in each hour of the study. Baseload generator output is also de-rated by scheduled outage rates. The total supply of power can exceed the demand for power to reflect the potential of spilling power or curtailment during certain hours. Distribution losses are incurred for traversing the distribution system, and are taken to be 5.3% in this study.

CONSERVATION_OF_ENERGY_NON_DISTRIBUTED$_{a,t}$		For every load area *a*, in each hour *t*, the amount of non-distributed energy ($NP_{a,t}$) consumed (i.e. demand that is satisfied from the central grid) plus losses incurred by traversing the distribution system (*dl*) cannot exceed
	$NP_{a,t} \times (1 + dl) \leq$	
Generation	$\sum_{gp(\neq vdp) \in GP_a} O_{gp,t}$	the total power generated in load area *a* in hour *t* by all non-distributed projects *gp* ($O_{gp,t}$), including baseload, flexible baseload, intermediate, dispatchable, and hydroelectric generation projects
Transmission	$+ \sum_{(a,a')} TR_{(a,a'),t} \times e_{(a,a')} - \sum_{(a'',a)} TR_{(a'',a),t}$	plus the total power supplied to load area *a* from other load areas *a'* via transmission ($TR_{(a,a'),t}$), de-rated by the transmission path efficiency ($e_{(a,a')}$), minus the total power exported from load area *a* to other load areas *a''* via transmission ($TR_{(a'',a),t}$)
Storage	$+ \sum_{sp \in SP_a} R_{sp,t} - \sum_{sp \in SP_a} S_{sp,t}$	plus the total energy supplied to load area *a* in hour *t* by storage projects *sp* in that load area ($R_{sp,t}$) minus the total energy that is stored by storage projects *sp* in that load area ($S_{sp,t}$).

SATISFY_LOAD$_{a,t}$ $$NP_{a,t} + \sum_{vdp \in GP_a} O_{vdp,t} \geq l_{a,t} - \sum_{DC} DR_{dc,a,t} + \sum_{DC} MDR_{dc,a,t}$$	For every load area *a* in each hour *t*, the total energy consumed from non-distributed sources ($NP_{a,t}$) and distributed renewable sources *vdp* ($O_{vdp,t}$) must be greater than or equal the pre-defined end-use system load ($l_{a,t}$) minus any demand shifted away from hour *t* via demand response by all demand categories *dc* ($DR_{dc,a,t}$) plus any demand shifted to hour *t* from other hours by all demand categories *dc* ($MDR_{dc,a,t}$).

B.6.2 RESERVE MARGIN CONSTRAINTS

1. ***The capacity reserve constraints*** address the system risk that arises from power plant outages due to various mechanical and electrical failures. The capacity reserve constraints require that the power system maintain a capacity reserve each load area in all hours, i.e. that there would be sufficient capacity available to provide at least 15 percent extra power above demand in every load area in every hour if all generators were working properly. In calculating the capacity reserve margin, the output of generators are therefore not de-rated by forced outage rates. Outages from the failure of transmission or storage assets are included via the use of the dispatch variables *(TR, R, S)*, which have already been de-rated by forced outage rate. SWITCH determines the reserve margin schedule concurrently with the load-satisfying dispatch schedule.

CONSERVATION_OF_ENERGY_NON_DISTRIBUTED_RESERVE$_{a,t}$	$NPR_{a,t} \times (1 + dl) \leq$	In every load area *a*, in each hour *t*, the amount of non-distributed capacity available to meet the capacity reserve margin ($NPR_{a,t}$) plus losses incurred by traversing the distribution system (*dl*) cannot exceed
Generation Capacity	$\sum_{vcp}\left(\sum_{i} G_{vcp,i} \times cf_{vcp,t}\right) + \sum_{p \in DP \cup IP \cup HP}\left(\sum_{i} G_{p,i}\right) + \sum_{p \in FBP \cup BP}\left(\sum_{i} G_{p,i} \times (1 - s_p)\right)$	the total capacity of all variable renewable non-distributed projects ($G_{vcp,i}$) multiplied by their capacity factor in hour *t* ($cf_{vcp,t}$), plus the total capacity of all dispatchable (*dp*), intermediate (*ip*), and hydro (*hp*) projects ($G_{p,i}$) plus the total capacity ($G_{p,i}$), adjusted by scheduled outage rate (s_p), of all flexible baseload (*fbp*) and baseload projects (*bp*) in load area *a* in hour *t*
Transmission Capacity	$+ \sum_{(a,a')} TR_{(a,a'),t} \times e_{(a,a')} - \sum_{(a'',a)} TR_{(a'',a),t}$	plus the total power transmitted to load area *a* from other load areas *a'* ($TR_{(a,a'),t}$), de-rated for the path's transmission efficiency ($e_{(a,a')}$), minus the total power transmitted from load area *a* to other load areas *a''* ($TR_{(a'',a),t}$)
Storage Capacity	$+ \sum_{sp \in SP_a} R_{sp,t} - \sum_{sp \in SP_a} S_{sp,t}$	plus the total output, of storage projects *sp* in load area *a* in hour *t* ($R_{sp,t}$) minus the energy stored by storage projects *sp* ($S_{sp,t}$).

SATISFY_RESERVE_MARGIN$_{a,t}$ $$NPR_{a,t} + \sum_{vdp \in VDP_a} O_{vdp,t} \geq (1+r) \times \left(l_{a,t} - \sum_{dc} DR_{dc,a,t} + \sum_{dc} MDR_{dc,a,t} \right)$$	For each load area *a*, in each hour *t*, the total non-distributed capacity ($NPR_{a,t}$) and variable renewable distributed output within that load area ($O_{vdp,t}$) available for consumption must be a pre-specified reserve margin (*r*) above the pre-defined system load ($l_{a,t}$) minus any demand shifted away from hour *t* via demand response by all demand categories *dc* ($DR_{dc,a,t}$) plus any demand shifted to hour *t* from other hours by all demand categories *dc* ($MDR_{dc,a,t}$). In this study, *r* is taken to be 0.15 for all load areas in all investment periods.

2. ***The operating reserve constraints*** ensure that electricity supply is able to follow electricity demand on the sub-hourly timescale. Operating reserve (spinning and quickstart) equal to a percentage of demand plus a percentage of variable renewable generation is maintained in each balancing area in each hour. At least half of the operating reserves must be spinning. Frequency or inertial reserves are not modeled in this study.

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 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 calculated as a percentage of demand plus a percentage of variable renewable generation in each balancing area in each hour.

SATISFY_OPERATING_RESERVE$_{ba,t}$ $$\sum_{p \in DP_{ba} \cup IP_{ba}} (SR_{p,t} + Q_{p,t}) + \sum_{p \in SP_{ba} \cup HP_{ba}} OP_{p,t} \geq operating\_reserve\_reqt_{ba,t}$$	In each balancing area *ba* in each hour *t*, the spinning reserve ($SR_{p,t}$) plus the quickstart reserve, ($Q_{p,t}$) 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 total operating (spinning plus quickstart) reserve requirement (*operating_reserve_reqt*$_{ba,t}$) in that balancing area in that hour. The operating reserve requirement is calculated as a percentage of demand plus a percentage of renewable generation in each balancing area in each hour.

B.6.3 POLICY CONSTRAINTS

1. ***The carbon cap constraint*** requires that the total carbon dioxide emissions from all generation sources cannot exceed a pre-specified emissions cap in every investment period. Emissions are incurred for power generation, provision of spinning reserves, cycling of plants below full load, and generator start-up. As implemented here, the carbon cap constraint limits the total amount of carbon emissions across all of WECC in each study period to a pre-defined level, generally reaching roughly 85 percent reductions relative to 1990 carbon emissions levels for the investment period 2046-2055. The reference 1990 carbon emissions level from electricity generation is 284.8 $MtCO_2$/yr. Non-CO_2 greenhouse gas emissions from power generation are not included in this study. An iterative process between the investment optimization and the post-investment dispatch check (Section B.8.1: Emissions) ensures that the final emissions quoted in this study are those that would be incurred when operating the power system over an entire year of hourly data, rather than just the hours sampled in the investment optimization.

CARBON_CAP$_i$ $$\sum_{p,t\in T_i} O_{p,t}\times hr_p \times CO_{2_{f_p}}\times hs_t + \sum_{p\in DP\cup IP,t\in T_i} SR_{p,t}\times sr_{penalty_p} \times CO_{2_{f_p}}\times hs_t + \sum_{p\in FBP\cup IP,t\in T_i} DC_{p,t}\times dc_{penalty_p} \times CO_{2_{f_p}} \times hs_t + \sum_{p\in DP\cup IP,t\in T_i} ST_{p,t}\times startup_{fuel_p} \times CO_{2_{f_p}} \times hs_t \leq carbon\_cap_i$$	In every period *i*, the total carbon emissions cannot exceed a pre-specified carbon cap (*carbon_cap*$_i$) for that period. Emissions are incurred from power generation (calculated as the project output ($O_{p,t}$) times the project heat rate at full load (hr_p) times the CO_2 content of the fuel for that project ($CO_{2_{f_p}}$)); plus the carbon emissions from spinning reserve from dispatchable and intermediate projects (calculated as the amount of spinning reserves provided ($SR_{p,t}$) times the project per unit heat rate penalty for providing spinning reserve (*sr_penalty*$_p$) times the CO_2 content of the fuel for that project ($CO_{2_{f_p}}$)); plus the carbon emissions from deep-cycling flexible baseload and intermediate projects below full load (calculated as the amount below full load ($DC_{p,t}$) times the heat rate penalty for cycling below full load (*dc_penalty*$_p$) times the CO_2 content of the fuel for that project ($CO_{2_{f_p}}$)); plus the emissions from starting up intermediate and dispatchable plants (calculated as the capacity started up since the previous hour ($ST_{p,t}$) times the startup fuel required (*startup_fuel*$_p$) times the CO_2 content of the fuel for that project ($CO_{2_{f_p}}$)). All hourly values are weighted by the hours represented by each sampled hour *t* (hs_t).

2. ***The RPS constraints*** require that a certain percentage of end-use demand be met by renewable energy sources in each load-serving entity, consistent with state-based Renewable Portfolio Standards. A load-serving entity may encompass a single load area or many load areas. More specifically, in each load-serving entity and in each investment period, the ratio of renewable energy certificates (RECs) delivered to that load-serving entity by qualifying renewable sources to end-use demand is greater than or equal to the fraction of end-use demand specified by existing RPS targets. Existing RPS targets are broken into two different categories: primary and distributed. Primary RPS targets can be satisfied by either distributed or central station renewable generation sources, whereas distributed RPS targets can only be satisfied by distributed renewable generation sources. The RPS constraints do not allow the use of unbundled (tradable) RECs, but primary RPS targets may be met by power imported over reserved transmission capacity as controlled by the *CONSERVATION_OF_REC* constraint. By definition, RECs do not undergo transmission,

storage or distribution losses.

MEET_PRIMARY_RPS$_{lse,i}$ $$\frac{\sum_{t\in T_i} REC_{lse,t}\times hs_t}{\sum_{t\in T_i,a\in A_{lse}} l_{a,t}\times hs_t} \geq rps\_p_{lse,i}$$	For every load-serving entity *lse* in every investment period *i*, the proportion of the renewable energy certificates consumed ($REC_{lse,t}$) in all load areas *a* within that load-serving entity (the set A_{lse}) in all hours *t* of that period (the set T_i) as a fraction of total end-use demand ($l_{a,t}$) in that period in that load-serving entity must be greater than or equal to the pre-defined primary RPS fraction ($rps\_p_{lse,i}$), for that load-serving entity for that period. Each timepoint in the set T_i is weighted by the number of sample hours it represents (hs_t).

CONSERVATION_OF_REC$_{lse,t}$ $$REC_{lse,t} \leq \sum_{rp\in RP_{lse}} O_{rp,t} + \sum_{a\in A_{lse},a'\notin A_{lse},f\in R} TR_{(a,a'),f,t} - \sum_{a''\notin A_{lse},a\in A_{lse},f\in R} TR_{(a'',a),f,t}$$	For every load-serving entity *lse* in every hour *t*, the amount of renewable energy consumed ($REC_{lse,t}$) cannot exceed the total output of renewable generators ($O_{rp,t}$) in the load-serving entity in that hour plus the energy from RPS-eligible fuels ($f\in R$) transmitted into the load-serving entity ($TR_{(a,a'),f,t}$) minus the energy from RPS-eligible fuels transmitted out of the load-serving entity ($TR_{(a'',a),f,t}$). Only transmission between load areas within different load-serving entities is included in the sums above. By definition, RECs do not undergo transmission, storage or distribution losses.

MEET_DISTRIBUTED_RPS$_{lse,i}$ $$\frac{\sum_{t\in T_i,vdp\in VDP_{lse}} O_{vdp,t}\times hs_t}{\sum_{t\in T_i,a\in A_{lse}} l_{a,t}\times hs_t} \geq rps\_d_{lse,i}$$	For every load-serving entity *lse* in every investment period *i*, the proportion of the power generated ($O_{vdp,t}$) from distributed renewable sources *vdp* in that load-serving entity (VDP_{lse}) in all hours *t* of that period (the set T_i) as a fraction of total load ($l_{a,t}$) in that period in that load-serving entity must be greater than or equal to the pre-defined distributed RPS fraction ($rps\_d_{lse,i}$), for that load-serving entity for that period. Each timepoint in the set T_i is weighted by the number of sample hours it represents (hs_t).

3. ***The California Solar Initiative constraint*** requires the installed capacity of distributed solar projects in California to meet or exceed 3 GW by 2016 and to maintain this capacity in all

subsequent investment periods. This constraint can be met with either commercial or residential photovoltaics.

CALIFORNIA_SOLAR_INITIATIVE$_{i\geq 2016}$ $$\sum_{vdp \in VDP_{cal}} G_{vdp,i} \geq csi\_target$$	For every investment period *i* that occurs on or after the year 2016, the sum of installed capacity of variable renewable distributed projects ($G_{vdp,i}$) within the state of California must exceed a pre-specified target capacity (*csi_target). csi_target* is taken as 3,000 MW in this study. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

4. ***The California Distributed Generation Mandate constraint***, not enabled by default, requires the installed capacity of distributed solar projects in California to meet or exceed 12 GW by 2020 and to maintain this capacity in all subsequent investment periods. This constraint can be met with either commercial or residential photovoltaics. This constraint is only included in scenarios that explicitly include the California distributed generation mandate.

CALIFORNIA_DG_MANDATE$_{i\geq 2020}$ $$\sum_{vdp \in VDP_{cal}} G_{vdp,i} \geq ca\_dg\_target$$	For every investment period *i* that occurs on or after the year 2020, the sum of installed capacity of variable renewable distributed projects ($G_{vdp,i}$ *for projects in* VDP_{cal}) within the state of California must exceed a pre-specified target capacity (*ca_dg_target). ca_dg_target* is taken as 12,000 MW in this study. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

5. ***The Mexico net export constraint*** caps the growth rate of net power exports from Mexico to surrounding load areas in the United States at no more than the historical electric power export growth rate between 2003 and 2008 of 3.2%/yr (Secretaría de Energía, 2010). Baja California Norte is the only Mexican load area simulated in this study. This constraint does not represent a specific public policy, but instead ensures that Mexico can export power to United States load areas while restricting the growth of exports to realistic levels.

MEX_EXPORT_LIMIT$_{a=MEX\_BAJA,i}$	For each investment period *i*, the sum of transmission capacity dispatched out of the load area *a=MEX_BAJA*, ($TR_{(a,a'),t}$) minus the sum of transmission capacity dispatched into

$$\sum_{(a,a'),t\in T_i} TR_{(a,a'),t} \times hs_t - \sum_{(a'',a),t\in T_i} TR_{(a'',a),t} \times hs_t \leq mex\_export\_lim_i$$	the load area *a=MEX_BAJA* ($TR_{(a'',a),t}$), weighted by the number of sample hours represented by hour *t* (hs_t), cannot exceed the specified export limit out of MEX_BAJA ($mex\_export\_lim_i$).

B.6.4 RESOURCE CONSTRAINTS

Large energy projects tend to be limited in size due to resource constraints such as land availability, geology, resource quality, etc. All renewable resources in SWITCH are constrained by resource availability. In addition, the availability of cogeneration with either renewable or non-renewable fuels is constrained to present levels. Compressed air energy storage is resource-constrained by underground geology. Other non-renewable resources (non-cogeneration natural gas, oil, coal, and nuclear) do not have explicit resource constraints, but are instead limited by cost and/or policy measures and are therefore not discussed further in this section.

1. ***For capacity limited projects*** (residential and commercial photovoltaic, geothermal, offshore and onshore wind, and compressed air energy storage), the amount of installed capacity at a specific project cannot exceed a pre-specified MW capacity limit.

$MAX\_RESOURCE\_PROJECT_{clp,i}$ $$\sum_i G_{clp,i} \leq cl_{clp}$$	For each capacity-limited project *clp* in every investment period *i*, the sum of generation capacity installed at the project in the current and all preceding periods *i* ($G_{clp,i}$) must not exceed the pre-specified capacity limit for that project (cl_{clp}). The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

2. ***Central station solar projects*** compete for the same locations and are thus constrained to not exceed the pre-specified available land area of any specific piece of land. Central station solar projects include central station photovoltaics and solar thermal trough systems with and without thermal storage.

MAX_RESOURCE_LAND$_{loc,i}$ $$\sum_{llp \in LLP_{loc},i} \frac{G_{llp,i}}{la_{llp}} \leq ll_{loc}$$	For each location *loc* in which land-area-limited projects are sited and every investment period *i*, the total capacity of land-area-limited projects *llp* at that location installed in the current and all preceding periods *i* ($G_{llp,i}$), divided by the land area per unit of installed capacity for the project (la_{llp}) must not exceed the pre-specified land-area limit for that location (ll_{loc}). The generator operational lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

3. ***Biogas and biomass solid projects*** are limited by the pre-specified amount of biogas or biomass available within each load area in each investment period.

MAX_RESOURCE_BIO$_{bf,a,i}$ $$\sum_{blp \in BLP_{a,bf},t \in T_i} O_{blp,bf,t} \times (hr_{blp} + ctd_{blp}) \times hs_t \leq bfl_{bf,a,i}$$	For each biofuel (biomass solid and biogas) *bf* in every load area *a* in every investment period *i,* the total consumption of that biofuel must not exceed a pre-specified biofuel availability limit ($bfl_{bf,a,i}$). The total consumption of biofuel is calculated as the sum over all bio-limited projects *blp* of biofuel type *bf* in all hours *t* in investment period *i* of power produced by bio-limited projects ($O_{blp,bf,t}$), multiplied by the project's heat rate (hr_{blp}) plus cogeneration thermal demand (in units of thermal energy demanded per MW generated) (ctd_{blp}), weighted by the number of hours represented by hour *t* (hs_t). The cogeneration heat demand term is zero for non-cogeneration plants. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

4. ***The amount of cogeneration resource*** available is limited by the current installed capacity at each cogeneration plant.

MAX_RESOURCE_COGEN$_{cbp,i}$ $$\sum_i G_{cbp,i} \leq cl_{cbp}$$	For each cogeneration project *cbp* in every investment period *i*, the sum of generation capacity installed at the project in the current and all preceding periods *i* ($G_{cbp,i}$) must not exceed the pre-specified capacity limit for that project (cl_{cbp}). The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

B.6.5 TRANSMISSION AND DISTRIBUTION CONSTRAINTS

1. ***Transmission paths*** can transfer no more energy in each hour in each direction between each pair of connected load areas than the path's rated thermal capacity, de-rated by its path derating factor. Once transmission capacity is installed, it is assumed to remain in operation for the remainder of the study.

MAX_TRANS$_{(a,a'),t}$ $$TR_{(a,a'),t} \leq (path\_derate_{(a,a')}) \times (et_{(a,a')} + \sum_i T_{(a,a'),i})$$	For each transmission path *(a, a')* in every hour *t*, the total amount of energy dispatched along the transmission path between two load areas (*a,a'*) in each hour *t* ($TR_{(a,a'),t}$) cannot exceed the sum of the pre-existing thermal transmission capacity ($et_{(a,a')}$) and the sum of additional thermal transmission capacity installed between the two load areas in the current and all preceding periods *i* ($T_{(a,a'),i}$), de-rated by the transmission path's derating factor ($path\_derate_{(a,a')}$).

2. ***Distribution capacity*** must be installed in order to serve peak demand in each load area and in each investment period. If demand response is not enabled, then only the *MIN_DISTRIBUTION_NO_DR* is enforced and consequently the amount of distribution capacity installed is completely determined by the exogenously specified demand profile. If demand response is enabled, both the *MIN_DISTRIBUTION_DR* and *MIN_DISTRIBUTION_NO_*DR constraints are enforced. Consequently, additional distribution capacity above projected peak demand may be installed in order to allow for demand response to shift demand to hours of peak demand. Such an event may occur if variable renewable generation exhibits a positive correlation with hours of peak demand.

MIN_DISTRIBUTION_NO_DR$_{a,i}$ $$ml_{a,i} \leq ed_a + \sum_i D_{a,i}$$	For each load area *a* in every investment period *i*, the pre-defined maximum end-use system load in period *i* ($ml_{a,i}$) must be less than or equal to the sum of pre-existing distribution capacity (ed_a) and additional distribution capacity installed in the load area in the current and all preceding periods *i* ($D_{a,i}$).

MIN_DISTRIBUTION_DR$_{a,t}$ $$l_{a,t} - \sum_{DC} DR_{dc,a,t} + \sum_{DC} MDR_{dc,a,t} \leq ed_a + \sum_i D_{a,i}$$	For each load area *a* in every hour *t*, the pre-defined end-use system load ($l_{a,t}$), minus any demand response provided in hour t from all demand categories *dc* ($DR_{dc,a,t}$) plus any demand shifted to hour t from other hours from all demand categories *dc* ($MDR_{dc,a,t}$), must be less than or equal to the sum of the pre-existing distribution capacity (ed_a) and additional distribution capacity installed in the load area in the current and all preceding periods *i* ($D_{a,i}$). This constraint is written over the set of hours *t* but will only be binding for a small number of hours in each investment period (likely only one), thereby setting the amount of distribution capacity installed in the investment period.

B.6.6 OPERATIONAL CONSTRAINTS

1. ***Variable renewable generators*** (solar and wind) produce the amount of power corresponding to their simulated historical power output in each hour, de-rated by their forced outage rate.

VAR_GEN$_{vp,t}$ $$O_{vp} = cf_{vp,t} \times (1 - o_{vp}) \times \sum_i G_{vp,i}$$	For each variable renewable generation project *vp* in every hour *t*, the expected amount of power produced by the variable renewable generator in that hour ($O_{vp,t}$) must equal the sum of generator capacity installed at generator *vp* in the current and preceding investment periods *i* ($G_{vp,i}$), de-rated by the generator's forced outage rate (o_{vp}), multiplied by the generator's capacity factor in hour *t* ($cf_{vp,t}$). The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

2. ***Baseload generators*** (nuclear, geothermal, biomass solid, biogas and cogeneration) must produce an amount of power equal to their installed nameplate capacity, de-rated by their forced and scheduled outage rates, in all hours in each investment period.

BASELOAD_GEN$_{bp,t}$ $$O_{bp,i} = (1 - o_{bp}) \times (1 - s_{bp}) \times \sum_i G_{bp,i}$$	For every baseload project *bp* and every hour *t*, the expected amount of power produced by the baseload generator in that hour ($O_{bp,t}$) cannot exceed the sum of generator capacity installed at generator *bp* in the current and preceding investment periods *i* ($G_{bp,i}$), de-rated by the generator's forced outage rate (o_{bp}) and scheduled outage rate (s_{bp}). The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

3. ***Flexible baseload generators*** (non-cogeneration coal) cannot commit more capacity in each day than their nameplate capacity, de-rated by their forced and scheduled outage rates.

MAX_DISPATCH_HOURLY$_{fbp,t}$ $$O_{fbp,t \in T_d} = O_{fbp,d}$$	For each flexible baseload generation project *fbp* in each hour *t* on day d (T_d is the set of hours 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.

MAX_DISPATCH$_{fbp,d}$ $$O_{fbp,d} \leq (1 - o_{fbp}) \times (1 - s_{fbp}) \times \sum_i G_{fbp,i}$$	For each flexible baseload generation project *fbp* on every day *d*, the power output on that day ($O_{fbp,d}$) cannot exceed the sum of generator capacity ($G_{fbp,i}$) installed at generator *fbp* in the current and preceding investment periods *i*, de-rated by the generator's forced outage rate (o_{fbp}) and scheduled outage rate (s_{fbp}). The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

MIN_DISPATCH$_{fbp,d}$ $$O_{fbp,d} \geq min\_loading\_frac_{fbp} \times \sum_i G_{fbp,i}$$	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* ($G_{fbp,i}$).

4. ***Intermediate generators*** (natural gas combined cycle plants and natural gas steam turbines) can commit no more capacity in each hour than their nameplate capacity, de-rated by their forced outage rate. Intermediate generation can provide no more power, spinning reserve, and quickstart capacity in each hour than the amount of project capacity that was committed in that hour. Spinning reserve cannot exceed a pre-specified fraction of capacity and can only be provided in hours when the plant is committed and online. Combined heat and power natural gas generators (cogenerators) are operated in baseload mode and are therefore not included here.

MAX_COMMIT$_{ip,t}$ $$C_{ip,t} \leq (1 - o_{ip}) \times \sum_i G_{ip,i}$$	For each intermediate generation project *ip* in every hour *t*, the capacity committed in that hour ($C_{ip,t}$) cannot exceed the sum of generator capacity installed at generator *ip* in the current and preceding investment periods *i* ($G_{ip,i}$), de-rated by the generator's forced outage rate (o_{ip}). The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

MIN_DISPATCH$_{ip,t}$ $$O_{ip,t} \geq min\_loading\_frac_{ip} \times C_{ip,t}$$	For each intermediate generation project *ip* in every hour *t*, the 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 committed capacity in that hour ($C_{ip,t}$).

MAX_DISPATCH$_{ip,t}$ $$O_{ip,t} + SR_{ip,t} + Q_{ip,t} \leq C_{ip,t}$$	For each intermediate generation project *ip* in every hour *t*, the 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_SPIN$_{ip,t}$ $$SR_{ip,t} \leq spin\_frac_{ip} \times C_{ip,t}$$	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 committed capacity (*spin_frac*$_{ip}$). This constraint is tied to the amount of capacity actually committed ($C_{ip,t}$) to ensure that spinning reserve is only provided in hours when the plant is also producing useful generation. The parameter *spin_frac*$_{ip}$ is calculated using the generator's 10-minute ramp rate.

STARTUP$_{ip,t}$ $$ST_{ip,t} \geq C_{ip,t} - C_{ip,t-1}$$	For each intermediate project *ip* in every hour *t*, the amount of capacity started up ($ST_{ip,t}$) equals the committed capacity in hour *t* ($C_{ip,t}$) minus the committed capacity in the previous simulated hour ($C_{ip,t-1}$). 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. $ST_{ip,t}$ should be considered a derived variable as this constraint will be binding due to startup costs incurred when $C_{ip,t}$ and $C_{ip,t-1}$ are not equal.

5. ***Dispatchable generators*** (natural gas combustion turbines) 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.

MAX_DISPATCH$_{dp,t}$ $$O_{dp,t} + SR_{dp,t} + Q_{dp,t} \leq (1 - o_{dp}) \times \sum_i G_{dp,i}$$	For each dispatchable generation project *dp* in every hour *t*, the expected 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}). The generator's operational lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

MAX_SPIN$_{dp,t}$ $$SR_{dp,t} \leq spin\_frac_{dp} \times O_{dp,t}$$	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 power dispatched by the dispatchable project ($O_{dp,t}$). This constraint ties the dispatch of spinning reserve to the amount of power actually dispatched $O_{dp,t}$ to ensure that spinning reserve is only provided in hours when the plant is also producing power.

STARTUP$_{dp,t}$ $$ST_{dp,t} \geq O_{dp,t} - O_{dp,t-1}$$	For each dispatchable project *dp* in every hour *t*, the amount of capacity started up ($ST_{dp,t}$) equals the power output in hour t ($O_{dp,t}$) minus the power output in the previous simulated hour ($O_{dp,t-1}$). 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. $ST_{dp,t}$ should be considered a derived variable as this constraint will be binding due to startup costs incurred when $O_{dp,t}$ and $O_{dp,t-1}$ are not equal.

6. ***Hydroelectric generators*** must provide output in each hour equal to or exceeding a pre-specified fraction – 50% in this study – 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% in this study. 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 in this study, 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.

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* 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. *min_dispatch_frac* is taken as 0.5 in this study.

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 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_OP_RESERVE$_{hp,t}$ $OP_{hp,t} \leq hydro\_op\_reserve\_frac \times hg_{hp}$	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_op_reserve_frac* is taken to be 0.2 in this study.

HYDRO_AVG_OUTPUT$_{hp,d}$ $$\sum_{t \in T_d} (O_{hp,t} + op\_reserve\_deploy\_frac \times OP_{hp,t}) = cf_{hp,d} \times hg_{hp} \times num\_hours\_simulated_d$$	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*. *op_reserve_deploy_frac* is taken to be 0.01 in this study.

7. ***Storage facilities*** (battery storage, pumped hydroelectric, and compressed air energy storage (CAES)) can store no more power in each hour than their maximum hourly store rate, de-rated by a forced outage rate, and dispatch no more power in each hour than total capacity, de-rated by a forced outage rate. CAES projects must maintain the proper ratio between dispatch of energy stored in the form of compressed air and energy dispatched from natural gas. In SWITCH, days are modeled as independent dispatch units, and as such, the energy dispatched by each storage project on each day must equal the energy stored by the project on that day, adjusted for the storage project's round-trip efficiency losses.

MAX_STORE_RATE$_{sp,t}$ $$S_{sp,t} \leq (1 - o_{sp}) \times r_{sp} \times \sum_i G_{sp,i}$$	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 capacity installed at that project in the current and preceding periods *i* ($G_{sp,i}$), de-rated by the storage project's forced outage rate (o_{sp}). For pumped hydro, $G_{sp,t}$ is equal to the preexisting capacity as no new capacity can be installed in this study. The storage project operational lifetime limits the extent of the sum over *i* to only periods in which the storage project would still be operational, but is not included here for simplicity.

MAX_BATTERY_STORAGE_DISPATCH$_{bp,t}$ $$R_{bp,t} + OP_{bp,t} \leq (1 - o_{bp}) \times \sum_i G_{bp,i}$$	For every battery storage project *bp* in every hour *t*, the amount of energy dispatched from the storage project in that hour ($R_{bp,t}$) plus the operating reserve provided in that hour ($OP_{bp,t}$) cannot exceed the sum of the storage project's power capacity installed in the current and preceding periods *i* ($G_{bp,i}$), de-rated by the storage project's forced outage rate (o_s). The storage project operational lifetime limits the extent of the sum over *i* to only periods in which the storage project would still be operational, but is not included here for simplicity.

MAX_CAES_DISPATCH$_{cp,t}$ $$R_{cp,t} + OP_{cp,t} + O_{cp,t} + SR_{cp,t} + Q_{cp,t} \leq (1 - o_{cp}) \times \sum_i G_{cp,i}$$	For every CAES storage project *cp* in every hour *t*, the sum of the energy released from storage ($R_{cp,t}$) and operating reserve ($OP_{cp,t}$) provided by the storage plant plus the energy ($O_{cp,t}$), spinning reserve ($SR_{cp,t}$) and quickstart reserve ($Q_{cp,t}$) provided from natural gas cannot exceed the plant's total power capacity installed in the current and preceding periods *i* ($G_{cp,i}$), de-rated by the plant's forced outage rate (o_{cp}). The storage project operational lifetime limits the extent of the sum over *i* to only periods in which the storage project would still be operational, but is not included here for simplicity.

CAES_COMBINED_DISPATCH$_{cp,t}$ $$R_{cp,t} = O_{cp,t} \times caes\_ratio$$	For every CAES project *cp* in every hour *t*, the amount of energy dispatched from storage ($R_{cp,t}$) must equal the amount of energy dispatched from natural gas ($O_{cp,t}$) multiplied by the dispatch ratio between storage and natural gas (*caes_ratio*). *caes_ratio* is derived from the storage efficiency and overall round-trip efficiency of CAES and is calculated to be 1.40.

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

STORAGE_ENERGY_BALANCE$_{sp,d}$ $$\sum_{t \in T_d} R_{sp,t} + op\_reserve\_deploy\_frac \times \sum_{t \in T_d} OR_{sp,t} = \sum_{t \in T_d} S_{sp,t} \times e_{sp}$$	For each storage project *sp* on each day *d*, the energy dispatched by the storage project in all hours *t* on day *d* ($R_{sp,t}$) must equal the energy stored by the storage project in all hours *t* on day *d*, de-rated by the storage project's round-trip efficiency (e_{sp}). It is assumed that operating reserve ($OR_{sp,t}$) is called upon a fraction of the time, (*op_reserve_deploy_frac*), and is therefore included in the energy balance. T_d is the set of hours on day *d*. *op_reserve_deploy_frac* is taken to be 0.01 in this study.

B.6.7 DEMAND RESPONSE CONSTRAINTS

By default, demand response is disabled. When demand response is enabled, the amount of demand that can be moved from or to an hour via demand response for each demand category in each load area 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 area – 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 in this study are electric vehicles and buildings (residential + commercial). The amount of demand that can be moved from or to an hour from electric vehicles is calculated using battery charging rates (Section A.5: Demand Response Hourly Potentials).

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 area *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_TO$_{dc,a,t}$ $$MDR_{dc,a,t} \leq dr\_to\_limit_{dc,a,t}$$	For every demand category *dc* in every load area *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 ($dr\_to\_limit_{dc,a,t}$).

DR_ENERGY_BALANCE$_{dc,a,d}$ $$\sum_{t \in T_d} DR_{dc,a,t} = \sum_{t \in T_d} MDR_{dc,a,t}$$	For every demand category *dc* in every load area *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 ($MDR_{dc,a,t}$).

B.7 PRESENT-DAY DISPATCH

We perform a present-day optimization for each scenario that serves as a reference to which future investment plans can be compared. In this present-day optimization, current generation, transmission, and storage capacity is operated subject to the constraints described above, but no new capacity is built with the exception of natural gas combustion turbines. The simulation year is fixed as 2013 (the year in which this study was performed), and parameters such as demand projections, fuel prices, biomass availability, etc., that vary by year are taken from 2013. Policy targets such as renewable portfolio standards, carbon caps, and distributed generation targets are not enforced as data on the capacity of existing power system infrastructure tends to lag behind that which is in the ground by a few years. The exclusion of policy constraints makes present-day dispatch an imperfect benchmark, but present-day dispatch still includes many important current aspects of power system economics and therefore is an acceptable benchmark for purposes of comparison to future investment results.

B.8 POST-INVESTMENT DISPATCH CHECK

The decisions made by each SWITCH optimization use a limited number of sampled hours over which to dispatch the electric power system. While the model has state-of-the art hourly resolution for a large-scale planning model, each investment period in this study optimizes on 144 sampled hours – much less than a full year of demand and variable renewable data. To verify that the model has in fact designed a power system that can function over a full year of hourly demand and variable renewable output data, a post-investment dispatch check is included. In this check, performed after each investment optimization, all investment decisions are held fixed and new, unseen hourly data is tested in batches of one day at a time. If there is not sufficient generation capacity to meet demand, operational, and reserve constraints on a given day, more peaking gas combustion turbine capacity is added to the system to compensate.

In total, 364 distinct days (8736 distinct hours) are simulated in the post-investment dispatch check. One day per year is not simulated because time zone conversion results in incomplete data for that day. The hourly weighting scheme used in the post-investment dispatch check ensures that 365 days per year are represented, so we refer to the simulated 8736 hours as a year of hourly data.

In addition to investment decision variables, three sets of prices in each investment period are determined by the investment optimization and subsequently passed to the post-optimization dispatch check:

1. Carbon price – taken from the dual value of the carbon cap constraint for each investment period. The dual value represents the change in total power system cost if the cap on carbon emissions was decreased by one ton. The carbon price has a uniform value over the entire WECC for each period in the post-dispatch optimization.
2. Natural gas wellhead fuel price – calculated as the sum of all expenditures on natural gas in a period divided by the quantity of natural gas consumed in that period. The natural gas wellhead price has a uniform value over the entire WECC for each period in

the post-dispatch optimization. As is the case in the investment optimization, regional natural gas price multipliers modify the wellhead price in the dispatch optimization.

3. Biomass solid fuel price – calculated as the sum of all expenditures on biomass solid fuel in a load area in an investment period divided by the quantity of biomass solid fuel consumed in that period in that load area. The biomass solid fuel price has a uniform value over each load area for each period in the post-investment dispatch check.

The current version of the post-investment dispatch check does not enforce the capacity reserve margin constraint, though the capabilities of grid assets are de-rated by forced and scheduled outage rates as is the case in the investment optimization. The necessary generation capacity to reliably operate the power system may be slightly underestimated by the exclusion of the reserve margin constraint from the post-investment dispatch check, but this error is not believed to be large. The dispatch check uses the same constraints and general structure as the investment optimization and therefore does not include binary unit commitment constraints, security constraints, or load flow transmission constraints.

Annual RPS targets and carbon emission caps are not included in the post-optimization dispatch check in order to allow the problem to be decomposed into separate optimization problems for each day. Unlike the main optimization, the dispatch simulation does not track renewable electricity through the transmission network and consequently does not report whether RPS targets can be met with the larger number of time points. Results from the investment optimization tend to be in most cases quantitatively similar to results from the post-investment dispatch check, so the omission of RPS targets in the post-investment dispatch check is not thought to introduce substantial error. When reporting the amount of imported or exported power to or from California from either renewable or non-renewable sources, it is assumed that the fraction of renewable and non-renewable power dispatched across the California border is equivalent in the investment optimization and the post-optimization dispatch check.

The post-investment dispatch check includes a price on carbon emissions in order to emulate the behavior of the carbon cap in the investment optimization. The carbon price is not guaranteed to produce identical emissions between the two problems, and as such an emissions tuning is performed.

B.8.1 EMISSIONS TUNING

In this study, we use the carbon emissions level as calculated by the *post-optimization dispatch check* as the final level of emissions quoted in all values and figures. The advantage of this method is that it ensures that the yearly amount of emissions from every power system designed by SWITCH is in line with emissions targets. The disadvantage of this method is that the carbon cap enforced in the investment optimization may not always result in the same emissions level that is calculated by the dispatch check. An iterative approach is employed between the investment optimization and the post-optimization dispatch check in order to arrive at the desired level of emissions in the dispatch check in the final investment period. In this iterative approach, investment optimizations for a given scenario are run with carbon emissions capped at different levels. A post-optimization dispatch check is performed on each

investment optimization, and the emissions level is noted. Further investment optimizations are run if the post-optimization dispatch check does not return the desired level of emissions. This process is continued until the desired emissions level is achieved in the dispatch check.

APPENDIX C IMPROVEMENTS FROM PHASE I AND THEIR IMPLICATIONS

In the two years between the completion of SWITCH model runs for the California Carbon Challenge Phase I report (Wei, et al., 2012; Wei, et al., 2013) and completion of model runs for Phase II (this document), many improvements were made to the modeling framework and input data. These improvements have had a discernible effect on study results, in many cases modifying conclusions of the Phase I. We discuss major improvements and their implications to the model results here. Many minor improvements were also made in this time frame, but are not discussed for the sake of brevity.

Inclusion of natural gas ramping and cycling costs

In the Phase I report, no carbon emission or cost penalties were assigned to natural gas generators during the start-up phase of operation. For the Phase II study, we have implemented cost and carbon emissions penalties for starting up non-cogeneration natural gas plants. In addition, the operation of gas steam and combined cycle generators was updated to include a linearized form of unit-commitment. These changes improved the dispatch of combined cycle and combustion turbine gas generation such that their operation in Phase II is more realistic relative to the present-day WECC power system. In Phase II, combined cycle units now tend to operate for large blocks of time within a day, whereas combustion turbines ramp up and down on a quicker timescale to follow demand.

Improved hourly sampling method

For Phase II, the modeling team investigated the sampling method by which sample hours are picked to serve as representative hours in the investment optimization. While the method of sub-sampling days every four hours was retained due to model run-time constraints, it was found that starting the sampling on median days at 2 am GMT more accurately reflected the total amount of energy from solar projects over the course of the day than did the previous method of starting at midnight GMT. This change generally decreases the amount of solar power in the generation mix by a few percent, being replaced in large part by wind power.

Ability to model deep decarbonization scenarios (> 85 % reduction from 1990 levels) through reliance on an entire year of hourly dispatch results

The average generation mix and carbon emission level of each scenario in Phase I were based off of dispatch as simulated in the investment optimization of SWITCH. As the investment optimization contains a limited number of sample hours, the emissions from a full year of hourly data can differ from that of the investment optimization. In Phase I, the average generation mix and carbon emission level were not reported from the post-optimization dispatch check as the implementation of this check was not yet complete. While the difference in emissions between the two optimizations tends to be relatively small for scenarios and

investment periods that do not include drastic emission reductions, the gap was found to widen to a few percentage points (relative to 1990 levels) in scenarios that reduced emissions to more than 80 % below 1990 levels by 2050. As we wanted the carbon emission reduction target to be based on the emissions level of the power system as dispatched over the course of an entire year, the emissions tuning phase was implemented. Relative to Phase I, this change increases the installed capacity of low-carbon sources of energy, and also transmission and storage capacity that helps to spatially and temporally balance variable renewable power sources. Greater installed capacity of these grid assets increases the cost of power in the 2050 time frame relative to Phase I.

Terrain cost multiplier included in transmission cost

In Phase I, the cost of building new transmission lines did not vary with the terrain over which the transmission line was passing. In Phase II a terrain-dependent transmission cost multiplier was implemented, thereby reducing the amount of transmission capacity built over mountains, through urban areas, or through forests.

Improved treatment of transmission dispatch via derating of transmission paths

In Phase I, the sum of thermal capacity of existing transmission lines in each transmission path between load areas was used as the power transfer capacity of the existing transmission path. Similarly, the installation of new transmission lines would increase the ability to transmit power along each transmission path by the rated thermal capacity of the new transmission line. In general in WECC, the thermal capacity of AC transmission lines does not represent the most stringent constraint on the ability to transfer power over long distances. DC transmission lines may also be subject to constraints that reduce their ability to carry power, though these constraints are generally less severe than is the case for AC lines. We therefore implemented a derating of transmission path thermal capacity in Phase II on all AC and DC transmission paths. This change reduces the amount of power sent along existing and new transmission corridors and thereby incentivizes the construction of generation and/or storage that is located closer to demand centers. When taken in conjunction with other changes made between Phase I and Phase II, it is difficult to determine the overall impact derating of transmission paths, other than an increase in power cost due to the increased difficulty to transmit power.

Demand response modeled in detail

In Phase I, we did not have the capability to model demand response in detail. For Phase II we added detailed assumptions about the hourly availability of demand response, which enables the exploration of demand response on power system infrastructure build-out in the *Demand Response Scenario*.

Updated generator and storage cost assumptions

For Phase II we updated future capital, fixed, and variable cost assumptions for generation and storage projects, drawing primarily on values from (Black and Veatch, 2012). These are the same values on which the National Renewable Energy Laboratory's Renewable Energy Futures

report is based, with a few relatively minor modifications. The Black and Veatch costs are generally more conservative than our previous cost estimates, and consequently cause the cost of power in later investment periods to increase relative to Phase I.

Once-through cooling and nuclear retirements

In Phase I, we did not require that power plants comply with California's Once-Through Cooling (OTC) regulations. In Phase II, we force all OTC plants to be retired on the schedule determined by the California Water Board. This change has minimal effect on results as almost all of these power plants were already retired by SWITCH before the OTC compliance date, either on the basis of economics or when they passed their maximum age.

Since the completion of Phase I, the permanent closure of the San Onofre Nuclear Generating Station (SONGS) was announced. SONGS is retired in all Phase II scenarios but was operational in all Phase I scenarios. In addition, we have updated the Diablo Canyon Power Plant and Columbia Generating Station nuclear power plants to have one 20-year relicensing, thereby retiring these generators before 2050. Palo Verde Nuclear Generating Station is assumed to be operational through 2050. As no new nuclear is built except in the *New Nuclear Scenario*, the amount of electricity from nuclear power in 2050 in Phase II is much less than is found in Phase I. Retirement of these plants incurs significant new costs by 2050 as their inexpensive zero-carbon electricity is replaced with other more expensive sources in order to meet carbon cap targets.

Solar and wind hourly data

The lack of hourly Canadian wind data in Phase I made it difficult for the Canadian province of Alberta to decarbonize as it was unable to develop any wind projects. This lack of wind data caused build-out of coal CCS in Alberta. When hourly Canadian wind data was added to the model, the amount of coal CCS developed in Alberta dropped, in most cases eliminating coal CCS from the province entirely.

Solar data from Phase I originated from publically available historical hourly solar data that was only available through 2005. Demand profiles and wind power production originate from the year 2006, and were thus out of sync by one year from the hourly solar data. Phase I consequently included many of the seasonal and diurnal correlations between solar power, wind, and demand, but did not match them to the same historical year. As demand tends to be positively correlated with power production, this discrepancy was unlikely to substantially overestimate the capacity benefits of solar power. For Phase II, we include historical hourly solar data from 2006 in SWITCH. While an important update for consistency within the modeling framework, drastic changes to results did not occur from this change.

Expanded capability to model a range of scenarios

For Phase II we developed capabilities to model many of the scenarios presented here. The scenarios presented here represent a more diverse set of possible futures than those presented in Phase I.

APPENDIX D DATA TABLES

Table D-1: California average hourly generation by fuel, imports, exports, and electricity demand in 2030 (average MW): Figure 4-3 top

	Coal	Gas	Geothermal	Solar	Wind	Biopower	Hydro	Nuclear	Coal CCS	Gas CCS	Biopower CCS	Exports: Non-Renewable	Imports: Non-Renewable	Imports: Renewable	**Demand**
Base Scenario	195	21793	547	1170	1628	1088	3985	2096	67	0	0	95	0	7433	**37607**
No CCS	227	21362	547	1415	1628	1088	3985	2096	0	0	0	0	79	7479	**37607**
Small Balancing Areas	194	21706	544	900	1738	1082	3972	2085	66	0	0	0	86	7336	**37414**
Limited Hydro	142	21702	1096	1654	1682	1088	2985	2096	67	0	0	0	1185	6278	**37607**
Expensive Transmission	259	21560	1729	1417	611	1094	3985	2096	67	0	0	0	434	6653	**37607**
Demand Response	226	20924	139	1438	2372	1085	3976	2091	67	0	0	0	120	7289	**37607**
12GW Distributed PV	195	20565	547	2344	1619	1100	3984	2096	67	0	0	0	205	7136	**37607**
California 50% RPS	414	18453	1466	1123	2660	1094	3984	2096	28	0	0	1194	0	9823	**37607**
Sunshot Solar	412	19150	139	4767	484	991	3984	2096	67	0	0	0	1365	6537	**37607**
Low Gas Price	142	24566	398	630	1602	1088	3985	2096	0	0	0	1614	0	7005	**37607**
New Nuclear	195	21920	547	1441	1620	1088	3985	2096	67	0	0	0	109	6827	**37607**
-20% Carbon Cap / BioCCS	400	21192	139	832	907	1085	3978	2091	46	0	1124	200	0	8200	**37500**
-40% Carbon Cap / BioCCS	379	21862	139	862	760	1085	3978	2091	67	0	1129	519	0	7950	**37499**
Reduced Efficiency Implementation	142	25437	139	661	4187	1100	3983	2096	67	0	0	0	917	6934	**43015**
Aggressive Electrification	142	24339	1690	697	2441	1100	3983	2096	67	0	0	0	571	6998	**41592**
Business As Usual	458	22450	139	1047	2972	1129	3984	2096	0	0	0	0	1280	8969	**41894**

Table D-2: Rest of WECC average hourly generation by fuel, imports, exports, and electricity demand in 2030 (average MW): Figure 4-3 bottom

	Coal	Gas	Geothermal	Solar	Wind	Biopower	Hydro	Nuclear	Coal CCS	Gas CCS	Biopower CCS	Exports: Non-Renewable	Exports: Renewable	Imports: Non-Renewable	**Demand**
Base Scenario	2651	30217	2508	3163	11925	1043	23472	4881	115	0	0	0	7433	95	**68217**
No CCS	1792	31331	2759	2936	11986	1043	23472	4881	0	0	0	79	7479	0	**68217**
Small Balancing Areas	2648	29842	2737	3370	11760	1037	23383	4855	114	0	0	86	7336	0	**67891**
Limited Hydro	463	36411	3730	3545	12308	1084	17598	4881	115	0	0	1185	6278	0	**68217**
Expensive Transmission	3599	30406	3374	2537	10225	1084	23472	4881	115	0	0	434	6653	0	**68217**
Demand Response	2650	30317	2104	3564	11717	1036	23406	4868	114	0	0	120	7289	0	**68217**
12GW Distributed PV	2652	31517	2839	2238	11211	1039	23472	4881	115	0	0	205	7136	0	**68217**
California 50% RPS	4376	28390	3673	3524	11937	1084	23474	4881	0	0	0	0	9823	1194	**68217**
Sunshot Solar	4313	28573	299	11529	6583	930	23475	4881	60	0	0	1365	6537	0	**68217**
Low Gas Price	574	32200	1519	3564	10795	1039	23474	4881	0	0	0	0	7005	1614	**68217**
New Nuclear	2379	30412	2768	2788	11718	1039	23472	4881	115	0	0	109	6827	0	**68217**
-20% Carbon Cap / BioCCS	3908	30069	1421	2973	10174	944	23408	4868	114	0	2552	0	8200	200	**68012**
-40% Carbon Cap / BioCCS	3681	28662	1311	2975	10179	922	23405	4868	85	0	3761	0	7950	519	**68003**
Reduced Efficiency Implementation	1682	34989	1305	3050	21180	1043	23468	4881	115	0	0	917	6934	0	**78316**
Aggressive Electrification	1719	30838	3932	2590	12074	1084	23470	4881	85	0	0	571	6998	0	**68639**
Business As Usual	5517	49716	1266	4097	11634	1548	23471	4881	0	0	0	1280	8969	0	**86415**

Table D-3: California average hourly generation by fuel, imports, exports, and electricity demand in 2050 (average MW): Figure 4-4 top

	Coal	Gas	Geothermal	Solar	Wind	Biopower	Hydro	Nuclear	Coal CCS	Gas CCS	Biopower CCS	Imports (Net)	Exports (Net)	**Demand**
Base Scenario	0	2211	4405	7281	10011	842	3614	0	118	6088	0	27355	0	**55796**
No CCS	0	3005	4405	6350	9181	842	2984	0	0	0	0	38510	0	**55796**
Small Balancing Areas	0	2006	4381	8421	10024	837	3628	0	117	5882	0	26599	0	**55511**
Limited Hydro	0	1997	4405	8795	10322	842	1985	0	118	5164	0	30028	0	**55796**
Expensive Transmission	0	1356	4405	11063	10333	842	3899	0	209	16950	0	11599	0	**55796**
Demand Response	0	1133	4393	21729	7085	839	3579	0	117	4937	0	16785	0	**55796**
12GW Distributed PV	0	2169	4405	7712	9990	842	3614	0	118	6125	0	26901	0	**55796**
California 50% RPS	0	2188	4405	7225	10009	842	3616	0	118	6429	0	27039	0	**55796**
Sunshot Solar	0	2905	4405	13651	9350	842	3596	0	67	3309	0	25271	0	**55796**
Low Gas Price	0	1684	4405	6691	9956	842	3708	0	67	11950	0	21909	0	**55796**
New Nuclear	0	4608	4405	4985	6099	840	3564	0	118	693	0	36050	0	**55796**
-20% Carbon Cap / BioCCS	20	11030	4393	7600	8395	681	3846	0	305	964	2274	21439	0	**55633**
-40% Carbon Cap / BioCCS	0	2476	4393	6282	9525	681	3587	0	67	6765	2277	25537	0	**55633**
Reduced Efficiency Implementation	0	1265	4405	12981	10593	842	3834	0	118	6080	0	31706	0	**65535**
Aggressive Electrification	0	2490	4405	12317	10583	842	3570	0	67	3593	0	32564	0	**62578**
Business As Usual	118	20948	4405	5752	6853	2747	3976	0	254	0	0	14081	0	**55568**

Table D-4: Rest of WECC average hourly generation by fuel, imports, exports, and electricity demand in 2050 (average MW): Figure 4-4 bottom

	Coal	Gas	Geothermal	Solar	Wind	Biopower	Hydro	Nuclear	Coal CCS	Gas CCS	Biopower CCS	Imports (Net)	Exports (Net)	**Demand**
Base Scenario	0	3764	6366	26814	82566	1064	21733	3798	123	10664	0	0	27355	**106627**
No CCS	0	7086	6366	43992	104668	1064	18120	3798	0	0	0	0	38510	**106627**
Small Balancing Areas	0	3912	6331	26041	80647	1058	21610	3778	123	10923	0	0	26599	**106128**
Limited Hydro	0	3692	6366	32311	94816	1064	11745	3798	123	12454	0	0	30028	**106627**
Expensive Transmission	0	2327	6366	20826	61868	1064	22602	3798	123	15729	0	0	11599	**106627**
Demand Response	0	7064	6348	35202	60044	1061	21845	3788	123	4843	0	0	16785	**106627**
12GW Distributed PV	0	3774	6366	26242	82849	1064	21716	3798	123	10543	0	0	26901	**106627**
California 50% RPS	0	3858	6366	26849	82505	1064	21735	3798	94	10308	0	0	27039	**106627**
Sunshot Solar	0	4231	6366	38051	76399	1064	21649	3798	68	6755	0	0	25271	**106627**
Low Gas Price	0	3134	6366	21709	78728	1064	22118	3798	68	11097	0	0	21909	**106627**
New Nuclear	0	5270	6366	4837	33950	1064	21743	81534	123	864	0	0	36050	**106627**
-20% Carbon Cap / BioCCS	0	11526	6348	23495	63608	899	22376	3788	3114	0	10339	0	21439	**106284**
-40% Carbon Cap / BioCCS	0	3201	6348	24773	73786	899	21469	3788	93	7924	10584	0	25537	**106277**
Reduced Efficiency Implementation	0	2800	6366	28681	91996	1064	22717	3798	123	26368	0	0	31706	**126318**
Aggressive Electrification	0	3317	6366	27816	103410	1064	21446	3798	94	15146	0	0	32564	**119633**
Business As Usual	7953	46271	6346	9040	34876	6100	23433	3798	4420	0	0	0	14081	**119642**

Table D-5: California installed capacity (MW) in 2030: Figure 4-6 top

	Coal	Gas	Geothermal	Solar	Wind	Biopower	Hydro	Nuclear	Coal CCS	Gas CCS	Biopower CCS	Storage	Transmission Import/Export
Base Scenario	230	43499	565	4638	4795	1319	9890	2323	79	0	0	2982	26701
No CCS	268	43408	565	5388	4795	1319	9890	2323	0	0	0	2982	26717
Small Balancing Areas	230	43066	565	3829	5155	1319	9890	2323	79	0	0	2982	26695
Limited Hydro	168	46352	1132	6127	4945	1319	9890	2323	79	0	0	2982	26869
Expensive Transmission	306	41302	1785	5412	2156	1326	9890	2323	79	0	0	2982	24334
Demand Response	268	39822	144	5485	6895	1319	9890	2323	79	0	0	2982	26635
12GW Distributed PV	230	42071	565	12000	4765	1318	9890	2323	79	0	0	2982	26613
California 50% RPS	490	41981	1514	4493	7675	1326	9890	2323	33	0	0	2982	26699
Sunshot Solar	490	38691	144	16373	1796	1182	9890	2323	79	0	0	2982	26925
Low Gas Price	168	43464	411	3000	4705	1319	9890	2323	0	0	0	2982	26659
New Nuclear	230	43417	565	5485	4765	1319	9890	2323	79	0	0	2982	26580
-20% Carbon Cap / BioCCS	487	41804	144	3624	2915	1319	9890	2323	55	0	1340	2982	26632
-40% Carbon Cap / BioCCS	463	42507	144	3718	2542	1319	9890	2323	79	0	1346	2982	26645
Reduced Efficiency Implementation	168	54622	144	3108	12483	1318	9890	2323	79	0	0	2982	25799
Aggressive Electrification	223	46413	1744	3205	7105	1334	9890	2323	79	0	0	2982	26650
Business As Usual	542	54664	144	4286	8755	1353	9890	2323	0	0	0	2982	26828

Table D-6: Rest of WECC installed capacity (MW) in 2030: Figure 4-6 bottom

	Coal	Gas	Geothermal	Solar	Wind	Biopower	Hydro	Nuclear	Coal CCS	Gas CCS	Biopower CCS	Storage	Transmission Import/Export
Base Scenario	4220	72129	2589	10840	33219	1227	52807	5409	136	0	0	1163	26701
No CCS	3403	72751	2848	10086	33416	1227	52807	5409	0	0	0	1163	26717
Small Balancing Areas	4006	72028	2841	11554	33138	1227	52807	5409	136	0	0	1875	26695
Limited Hydro	1338	81033	3851	12093	34403	1276	52807	5409	136	0	0	3014	26869
Expensive Transmission	4845	73696	3484	8774	28485	1276	52807	5409	136	0	0	1135	24334
Demand Response	4790	69950	2178	12129	32772	1222	52807	5409	136	0	0	1017	26635
12GW Distributed PV	4213	73460	2931	7844	31026	1222	52807	5409	136	0	0	1070	26613
California 50% RPS	5174	70217	3792	11999	33653	1276	52807	5409	0	0	0	1170	26699
Sunshot Solar	5137	74605	308	39532	18579	1106	52807	5409	70	0	0	2387	26925
Low Gas Price	2368	75331	1569	12144	30164	1222	52807	5409	0	0	0	1362	26659
New Nuclear	4618	71821	2858	9565	32435	1222	52807	5409	136	0	0	1170	26580
-20% Carbon Cap / BioCCS	4959	72033	1472	10187	28224	1112	52807	5409	136	0	3044	1243	26632
-40% Carbon Cap / BioCCS	4845	70212	1357	10193	28191	1087	52807	5409	100	0	4485	1169	26645
Reduced Efficiency Implementation	2231	86446	1347	10547	60293	1227	52807	5409	136	0	0	3748	25799
Aggressive Electrification	2319	76487	4060	8865	33655	1276	52807	5409	100	0	0	1144	26650
Business As Usual	6574	99855	1307	13865	32313	1828	52807	5409	0	0	0	1702	26828

Table D-7: California installed capacity (MW) in 2050: Figure 4-7 top

	Coal	Gas	Geothermal	Solar	Wind	Biopower	Hydro	Nuclear	Coal CCS	Gas CCS	Biopower CCS	Storage	Transmission Import/Export
Base Scenario	0	24684	4548	24733	33007	989	9890	0	139	14308	0	11447	50176
No CCS	0	20788	4548	22011	29663	989	9890	0	0	0	0	15442	68616
Small Balancing Areas	0	23959	4548	28039	33256	989	9890	0	139	14009	0	13558	48582
Limited Hydro	0	22845	4548	28828	34290	989	9890	0	139	12690	0	12946	58312
Expensive Transmission	0	23539	4548	35026	35190	989	9890	0	247	31968	0	13103	30320
Demand Response	0	20021	4548	73986	21540	989	9890	0	139	10387	0	7065	36223
12GW Distributed PV	0	24276	4548	29490	32948	989	9890	0	139	14444	0	11885	50379
California 50% RPS	0	24358	4548	24487	32999	989	9890	0	139	15072	0	10987	50051
Sunshot Solar	0	23059	4548	45018	30300	989	9890	0	79	6903	0	19399	49734
Low Gas Price	0	20685	4548	22219	32646	989	9890	0	79	24972	0	8612	45703
New Nuclear	0	38722	4548	17355	18360	986	9890	0	139	1316	0	8044	57600
-20% Carbon Cap / BioCCS	24	43747	4548	25686	26349	799	9890	0	361	1473	2712	14598	39829
-40% Carbon Cap / BioCCS	0	23322	4548	21291	31290	799	9890	0	79	16015	2716	9258	48856
Reduced Efficiency Implementation	0	33196	4548	37237	36270	989	9890	0	139	14335	0	10238	58820
Aggressive Electrification	0	27133	4548	38314	35580	989	9890	0	79	8381	0	14229	67562
Business As Usual	139	72858	4548	19225	21120	3254	9890	0	300	0	0	4309	31969

Table D-8: Rest of WECC installed capacity (MW) in 2050: Figure 4-7 bottom

	Coal	Gas	Geothermal	Solar	Wind	Biopower	Hydro	Nuclear	Coal CCS	Gas CCS	Biopower CCS	Storage	Transmission Import/Export
Base Scenario	0	49424	6572	83977	257529	1252	52807	4209	146	23460	0	23294	50176
No CCS	0	58071	6572	139966	313728	1252	52807	4209	0	0	0	48478	68616
Small Balancing Areas	0	47699	6572	82863	252095	1252	52807	4209	146	24099	0	25264	48582
Limited Hydro	0	57301	6572	100751	298739	1252	52807	4209	146	28986	0	49773	58312
Expensive Transmission	0	41110	6572	66603	204310	1252	52807	4209	146	29531	0	24190	30320
Demand Response	0	59649	6572	123632	183103	1252	52807	4209	146	9081	0	9519	36223
12GW Distributed PV	0	50755	6572	81879	258564	1252	52807	4209	146	23254	0	23199	50379
California 50% RPS	0	48848	6572	84035	257338	1252	52807	4209	111	22588	0	23598	50051
Sunshot Solar	0	60240	6572	123142	232341	1252	52807	4209	81	14493	0	34887	49734
Low Gas Price	0	49758	6572	68732	245677	1252	52807	4209	81	25142	0	19579	45703
New Nuclear	0	35779	6572	16644	98836	1252	52807	90353	146	1531	0	14398	57600
-20% Carbon Cap / BioCCS	0	58191	6572	75872	196309	1059	52807	4209	4139	0	12330	26047	39829
-40% Carbon Cap / BioCCS	0	46840	6572	76881	227031	1059	52807	4209	111	17798	12622	21000	48856
Reduced Efficiency Implementation	0	46830	6572	89170	282768	1252	52807	4209	146	55612	0	27446	58820
Aggressive Electrification	0	62067	6572	83904	324330	1252	52807	4209	111	36497	0	36618	67562
Business As Usual	9521	121006	6552	30374	103892	7241	52807	4209	5251	0	0	13341	31969

Table D-9: Average cost of power across WECC ($2013/MWh): Figure 4-10

	2013	2020	2030	2040	2050
Base Scenario	108	104	110	128	189
No CCS	108	104	110	130	232
Small Balancing Areas	109	104	110	129	190
Limited Hydro	108	106	116	140	221
Expensive Transmission	109	105	113	129	193
Demand Response	108	104	109	123	159
12GW Distributed PV	108	106	112	129	191
California 50% RPS	108	104	111	128	189
Sunshot Solar	108	100	105	116	182
Low Gas Price	106	102	101	121	178
New Nuclear	108	104	110	126	149
-20% Carbon Cap / BioCCS	108	104	111	123	161
-40% Carbon Cap / BioCCS	108	104	112	126	193
Reduced Efficiency Implementation	107	102	111	139	190
Aggressive Electrification	108	104	111	139	202
Business As Usual	106	100	106	113	124