SWITCH MODEL AND DATA DESCRIPTION: 2050 TIMEFRAME

December 2011

SWITCH 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 at the University of California, Berkeley.

SWITCH Model Description

1. Study Years, Months, Dates and Hours

To simulate power system dynamics in WECC 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. For this study, a single investment period contains historical data from 12 months, two days per month and six hours per day. There are four ten-year long investment periods: 2015-2025, 2025-2035, 2035-2045, and 2045-2055 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 taken to represent the conditions within that period, e.g. results for the year 2050 originate directly from the 2045-2055 investment period.

The peak and median day from each historical month are sampled to represent 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. This weighting scheme ensures 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, emphasizes the economics of dispatching the system under 'average' load conditions, and forces the system to plan for capacity availability at times of high grid stress.

Weather conditions and the subsequent output of renewable generators dependent on these conditions can be correlated not only across renewable sites in space and time, but also correlated with electricity demand. A classic example of this type of correlation is the large magnitude of air conditioning load that is present on sunny, hot days. To include these correlations in SWITCH as much as possible, time-synchronized, historical hourly load and generation profiles for locations across WECC are employed. Dates in future investment periods correspond to a distinct historical date from 2006, for which historical data on hourly loads, simulated hourly wind capacity factors, and monthly hydroelectric availability over the Western United States, Western Canada, and Northern Baja Mexico are used. Solar capacity factors are calculated from hourly 2005 solar isolation data, as 2006 data was not available in the proper form. The day of year and hour of day is synchronized between the 2005 solar data and the 2006 wind and load data, thereby maintaining diurnal and seasonal correlations between load, wind, and solar. Hourly load data is scaled to projected future demand as is discussed in the description of the Base Case, Frozen Efficiency and Extra Electrification load profiles, while solar, wind and hydroelectric resource availability is used directly from historical data.

To make the optimization computationally feasible, each day is sampled every four hours, thereby including six distinct hours of load and resource data in each study date. For median days, hourly sampling begins at midnight Greenwich Mean Time (GMT) and includes hours 0, 4, 8, 12, 16, and 20. For peak days, hourly sampling is offset to ensure the peak hour is included, which may be at 14:00 Pacific Standard Time (PST) on some days and 15:00 PST on other days. These varying offsets can be seen upon close examination of hourly dispatch figures in the results section.

2. Important Indices

Important Sets and Indices		
Set	***Index***	***Description***
I	i	investment periods
M	m	months
D	d	dates
T	t	hours
$T_d \subset \mathrm{T}$	--	set of all hours on date d
$T_i \subset \mathrm{T}$	--	set of all hours in investment period i
A	a	load areas
LSE	lse	load-serving entities
BA	ba	balancing areas
F	f	fuel categories
$R \subset F$	r	set of RPS-eligible fuel categories
G	g	all generators
$C \subset G$	c	dispatchable generators
$VD \subset G$	vd	intermittent distributed generators
$VN \subset G$	vn	intermittent non-distributed generators
$B \subset G$	b	baseload generators
$S \subset G$	s	storage projects
$P \subset G$	p	pumped hydroelectric projects
$H \subset G$	h	non-pumped hydroelectric projects
$G_a \subset G$	--	set of generators in load area a
$C_a \subset C$	--	set of dispatchable generators in load area a
$VD_a \subset VD$	--	set of intermittent distributed

		generators in load area *a*
$VN_a \subset VN$	--	set of intermitted non-distributed generators in load area *a*
$B_a \subset B$	--	set of baseload generators in load area *a*
$S_a \subset S$	--	set of storage generators in load area *a*
$P_a \subset P$	--	set of pumped hydroelectric generators in load area *a*
$H_a \subset H$	--	set of hydroelectric generators in load area *a*
$G_{ba} \subset G$	--	set of generators in balancing area *ba*
$C_{ba} \subset C$	--	set of dispatchable generators in balancing area *ba*
$VD_{ba} \subset VD$	--	set of intermittent distributed generators in balancing area *ba*
$VN_{ba} \subset VN$	--	set of intermitted non-distributed generators in balancing area *ba*
$B_{ba} \subset B$	--	set of baseload generators in balancing area *ba*
$S_{ba} \subset S$	--	set of storage generators in balancing area *ba*
$P_{ba} \subset P$	--	set of pumped hydroelectric generators in balancing area *ba*
$H_{ba} \subset H$	--	set of hydroelectric generators in balancing area *ba*
$A_{lse} \subset A$	--	set of load areas in load-serving entity *lse*

3. Decision Variables: Capacity Investment

The model's first set of decision variables consists of the following infrastructure investment choices for the power system, which are made at the beginning of each ten-year investment period.

Capacity Investment Decision Variables:

1. Amount of new generation capacity to install of each generator type in each load area
2. Amount of transmission capacity to add between each pair of load areas
3. Whether to operate each existing power plant in each period

Investment Decision Variables	
$G_{g,i}$	Capacity installed in period *i* at plant *g* (further subdivided into generator types including dispatchable plants *c*, baseload plants *b*, storage plants *s*, hydroelectric plants *h*, and pumped hydroelectric plants *p*)
$CG_{c,i}$	Capacity installed in period *i* at dispatchable project *c*
$VDG_{vd,i}$	Capacity installed in period *i* at distributed intermittent project *vd*
$VNG_{vn,i}$	Capacity installed in period *i* at non-distributed intermittent project *vn*
$BG_{b,i}$	Capacity installed in period *i* at baseload project *b*
$T_{a,a',i}$	Capacity installed in period *i* between load area *a* and load area *a'*
$SG_{s,i}$	Capacity installed in period i at storage project *s*

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 only important for projects with long construction times such as nuclear plants and compressed air energy storage projects, which could not be finished by 2015, even if construction began today. Carbon Capture and Sequestration (CCS) generation cannot be built in the first investment period of 2015-2025, as this technology is not likely to be mature enough to able to be deployed at large (GW) scale before 2020. New nuclear plants must have a minimum capacity of 1 GW to reflect the minimum feasible nuclear plant size. Installation 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 the ~800 existing power plants in WECC. All existing plants except for nuclear plants are forced to retire at the end of their operational lifetime. Nuclear plants can extend operation past their operational lifetime, but are required to pay operations and maintenance, as well as fuel costs for which any period in which they are operational. Hydroelectric facilities are required to operate throughout the whole study as, in addition to their value as electric generators, they also have much value in controlling stream flow.

New high-voltage transmission capacity is built along existing transmission corridors between the largest capacity substations of each load area. If no transmission corridor exists between two load areas, new transmission lines can be built at 1.5 times the straight-line transmission cost of \$1000 $MW^{-1}mi^{-1}$, reflecting the difficulty of transmission siting and permitting. 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. Existing transmission links that are approximated well by two or more shorter links between load areas are removed from the new expansion decisions. Investment in transmission lines greater than 300 km in length is approximated by investment in a handful of shorter links.

Investment in new local transmission and distribution within a load area is included as a sunk cost and hence does not have associated decision variables.

4. Decision Variables: Dispatch

4.1. Generation Dispatch

The second set of decision variables includes choices made in every study hour about how to dispatch generation, storage, and transmission in order to meet load.

Dispatch Decision Variables:

1. Amount of power to generate from each dispatchable (hydroelectric or natural gas) generator in each load area in each hour
2. Amount of power to transfer along each transmission corridor in each hour
3. Amount of power to store and release at each storage facility (pumped hydroelectric, compressed air energy storage, and sodium-sulfur battery plant) in each hour

Hourly dispatch decisions are not made for baseload generators because this type of generator, if kept running in an investment period, is assumed to produce the same amount of power in each hour of that period. Hourly dispatch decisions are also not made for intermittent renewable generators such as wind and solar because renewable facilities produce an amount of power that is exogenously calculated: an hourly capacity factor is specified based on the weather conditions on the corresponding historical hour at the location of each renewable plant. Excess renewable generation can occur in any hour - the excess is simply curtailed.

Dispatch Decision Variables	
$O_{g,t}$	Energy output of plant *g* in hour *t* (further subdivided into generator types including dispatchable plants *c*, baseload plants *b*, storage plants *s*, hydroelectric plants *h*, and pumped hydroelectric plants *p*)
$C_{c,t}$	Energy dispatched in hour *t* from dispatchable project *c*
$Tr_{a,a',t}$	Power dispatched in hour *t* along the transmission line between load area *a* and load area *a'*
$S_{s,t,f}$	Energy stored in hour *t* of fuel category *f* at storage project *s*
$R_{s,t,f}$	Energy released in hour *t* of fuel category *f* from storage project *s*
$H_{h,t}$	Energy dispatched in hour *t* from non-pumped hydroelectric project *h*
$PH_{p,t,f}$	Watershed energy dispatched in hour *t* of fuel category *f* from pumped-hydroelectric project *p*

$PHD_{p,t,f}$	Stored energy dispatched in hour t of fuel category f from pumped-hydroelectric project p
$PHS_{p,t,f}$	Energy stored in hour t of fuel category f at pumped-hydroelectric project p
$SP_{g,t}$	Spinning reserve provided by thermal dispatchable generator g in hour t (variable used only for dispatchable generators c)
$Q_{g,t}$	Quickstart capacity provided by thermal dispatchable generator g in hour t (variable used only for dispatchable generators c)
$OP_{g,t}$	Operating reserve (spinning and quickstart) provided by hydroelectric (h), pumped hydroelectric (p), and storage (s) plants in hour t

4.2. Dispatch 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,'[1] This standard dictates that contingency reserves 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. As operating reserves are a subhourly ancillary service, this represents the average amount necessary over the course of an hour. In addition, 'variability' reserves equal to 5 percent of the wind and solar output in each hour are held to cover the additional uncertainty imposed by generation intermittency.

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

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 intermittent renewable output. At present, WECC operates as 39 balancing areas (GE Energy 2010), but in light of the large benefits of increased balancing area size, their functions will likely be consolidated in the future. The Western Wind and

[1] Available at: http://www.nerc.com/files/BAL-STD-002-0.pdf.

Solar Integration Study assumes five regional balancing area in WECC for operating reserves – Arizona-New Mexico, Rocky Mountain, Pacific Northwest, Canada, and California – as their "statistical analysis showed, incorporating large amounts of intermittent 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 subregion as the balancing area in its optimization. Six balancing areas are modeled: Arizona-New Mexico (AZNMSNV), Rocky Mountain (RMPA), California (CA), Pacific Northwest (NWPP), Canada (NWPP Canada), and Mexico (MX).

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 CAES, 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.

5. Objective Function and Economic Evaluation

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 yearly by all active power plants and storage projects
3. variable costs incurred for each MWh produced by each plant, including variable O&M costs, fuel costs to produce electricity, and any carbon costs of greenhouse gas emissions
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

Objective function: minimize the total cost of meeting load			
Generation and	Capital	$\sum_{g,i} G_{g,i} \cdot c_{g,i}$	The capital cost incurred for installing capacity at plant g in investment period i is calculated as the generator size in MW $G_{g,i}$ multiplied by the capital cost (including installation and connect costs) of that type of generator in \$2007 / MW $c_{g,i}$.

	Fixed O&M	$+(ep_g + \sum_{g,i} G_{g,i}) \cdot x_{g,i}$	The fixed operation and maintenance costs paid for plant g in investment period i are calculated as the total generation capacity of the plant in MW (the pre-existing capacity ep_g at plant g plus the capacity installed in all investment periods i) multiplied by the recurring fixed costs associated with that type of generator in \$2007 / MW $x_{g,i}$.
	Variable	$+\sum_{g,t} O_{g,t} \cdot \left(m_{g,t} + f_{g,t} + c_{g,t}\right) \cdot hs_t$ $+\sum_{g,t} SP_{g,t} \cdot (spf_{g,t} + spc_{g,t}) \cdot hs_t$	The variable costs paid for operating plant g in time point t are calculated as the power output in MWh $O_{g,t}$ multiplied by the sum of the variable costs associated with that type of generator in \$2007 / MWh. The variable costs include maintenance $m_{g,t}$, fuel $f_{g,t}$, and a carbon cost $c_{g,t}$ (not included in this study), and are weighted by the number of hours each time point represents, hs_t. Variable costs also include the per unit fuel ($spf_{g,t}$) and carbon ($spc_{g,t}$) costs incurred by thermal dispatchable plants providing spinning reserve, $SP_{g,t}$.
Transmission	Capital	$+\sum_{a,a',i} T_{a,a',i} \cdot l_{a,a'} \cdot t_{a,a',i}$	The cost of building or upgrading transmission lines between two load areas a and 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 new line $l_{a,a'}$, and the area-adjusted per-km cost of building new transmission in \$2007 / MW · km $t_{a,a',i}$. Transmission can only be built between load areas that already are connected or that are adjacent to each other.
	O&M	$+\sum_{a,a',i} T_{a,a',i} \cdot l_{a,a'} \cdot x_{a,a',i}$	The cost of maintaining new transmission lines between two load areas a and 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 new line $l_{a,a'}$, and the area-adjusted per-km cost of maintaining new transmission in \$2007 / MW · km $x_{a,a',i}$.
Distribution		$+\sum_{a,i} d_{a,i}$	The cost of upgrading local transmission and distribution within a load area a in investment period i is calculated as the cost of building and maintaining the upgrade in \$2007 / MW, $d_{a,i}$. No decision variables are associated with these costs.
Sunk		$+\ s$	Sunk costs include capital payments for existing plants, existing transmission networks, and existing distribution networks.

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 – 2015 to 2055 – are included in the objective function. The present day capital cost of building each type of power plant or storage project is reduced via an exponential decay function using a capital cost declination rate (see the New Generators: Capital Costs section). The capital cost of each project is locked in at the first year of construction. Construction costs for power plants 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.

For optimization purposes, all costs during the study are discounted to a present-day value using a common real discount rate of 7% (White House Office of Management and Budget 2010), so that costs incurred later in the study have less impact than those incurred earlier. All costs are specified in real terms, indexed to the reference year 2007.

6. Constraints

The model includes five main sets of constraints: those that ensure that load is satisfied, those that maintain the capacity reserve margin, those that require that operating reserve be maintained, those that enforce Renewable Portfolio Standards (RPS), and those that impose a carbon cap.

The load-meeting constraints require that the power system is dispatched to meet load in every hour in every load area while providing the least expensive power based on expected generation, storage, and transmission availability. The nameplate capacity of these grid assets is de-rated by its forced outage rate to represent the amount of power generation capacity that is available on average in each hour of the study. Baseload generators are also de-rated by their scheduled outage rates.

The capacity reserve margin constraints require that the power system maintain a planning reserve margin at all times, i.e. that it would have sufficient capacity available to provide at least 15 percent extra power above load in every load area in every hour if all generators, storage projects and transmission lines are working properly. In calculating reserve margin, the outputs of these grid assets are therefore not de-rated by forced outage rates. SWITCH determines the reserve margin schedule concurrently with the load-satisfying dispatch schedule.

The operating reserve constraints ensure that an operating reserve equal to a percentage of load plus a percentage of intermittent generation is maintained in all hours, half of which must be spinning reserve.

The RPS constraints require that a certain percentage of load be met by renewable energy sources, consistent with state-based Renewable Portfolio Standards.

The carbon cap constraints limit the total amount of carbon emissions in each study period to a pre-defined level, e.g. 80% below 1990 carbon emissions levels for the investment period

2045-2055.

6.1. Load-Meeting Constraints

1. Natural gas dispatchable generators (combined cycle, combustion turbine, and steam turbine) can provide no more power, spinning reserve, and quickstart capacity in each hour than their nameplate capacity, de-rated by their forced outage rate. Combined heat and power natural gas generators (cogenerators) are operated in baseload mode and are therefore not included here. 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$_{c,t}$ $C_{c,t} + SP_{c,t} + Q_{c,t} \le (1 - o_c) \cdot \sum_i CG_{c,i}$	For each dispatchable project *c* in every hour *t*, the expected amount of power $C_{c,t}$, spinning reserve $SP_{c,t}$, and quickstart capacity $Q_{c,t}$ supplied by the dispatchable generator in that hour cannot exceed the sum, de-rated by the generator's forced outage rate o_c, of generator capacities $CG_{c,i}$ installed at generator *c* in the current and preceding periods *i*. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational.

MAX_SPIN$_{c,t}$ $SP_{c,t} \le \frac{spin\_frac_c}{1 - spin\_frac_c} \cdot C_{c,t}$	For each dispatchable project *c* in every hour *t*, the spinning reserve $SP_{c,t}$ supplied by the dispatchable generator in that hour cannot exceed a pre-specified fraction of capacity. This constraint is tied to the amount actually dispatched $C_{c,t}$ to ensure that spinning reserve is only provided in hours when the plant is also producing useful generation.

2. Intermittent 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. Intermittent generation is broken into non-distributed and distributed for use in the conservation of energy constraints below. These constraints define the derived variables $VD_{vd,t}$ and $VN_{vn,t}$, and as such do not appear in the compiled mixed-integer linear program.

DISTRIBUTED_VAR_GEN$_{vd,t}$	For each distributed intermittent project *vd* in every hour *t*, the expected amount of power, $VD_{vd,t}$, produced by the dispatchable generator in that hour must equal the sum, de-rated by the generator's forced outage rate o_{vd}, of generator

$VD_{vd,t} = cf_{vd,t} \cdot (1 - o_{vd}) \cdot \sum_i VDG_{vd,i}$	capacities $VDG_{vd,i}$ installed at generator *vd* in the current and preceding periods *i*, multiplied by the generator's capacity factor in hour *t*, $cf_{vd,t}$. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational.
$NON\_DISTRIBUTED\_VAR\_GEN_{vn,t}$ $VN_{vn,t} = cf_{vn,t} \cdot (1 - o_{vn}) \cdot \sum_i VNG_{vn,i}$	For each distributed intermittent project *vn* in every hour *t*, the expected amount of power, $VN_{vn,t}$, produced by the dispatchable generator in that hour must equal the sum, de-rated by the generator's forced outage rate o_{vn}, of generator capacities $VNG_{vn,i}$ installed at generator *vn* in the current and preceding periods *i*, multiplied by the generator's capacity factor in hour *t*, $cf_{vn,t}$. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational.

3. Baseload generators (nuclear, coal, geothermal, biomass solid, biogas and cogeneration) must produce an amount of power equal to their nameplate capacity, de-rated by their forced and scheduled outage rates. This constraint defines the derived variable $B_{b,t}$ and as such does not appear in the compiled mixed-integer linear program.

$BASELOAD\_GEN_{b,t}$ $B_{b,t} = (1 - o_b) \cdot (1 - s_b) \cdot \sum_i BG_{b,i}$	For every baseload project *b* and every hour *t*, the expected amount of power, $B_{b,a,t}$, produced by each baseload generator *b* in each hour *t* cannot exceed the sum, de-rated by the generator's forced outage rate o_b and scheduled outage rate s_b, of generator capacities $BG_{b,i}$ installed at generator *b* in the current and preceding periods *i*. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational.

4. The amount of energy produced from all non-pumped hydroelectric facilities in a load area must equal or exceed 50% of the average non-pumped hydroelectric energy production for that load area in each hour, in order to maintain downstream water flow. The total amount of energy produced in each hour, on a load area basis, from all pumped and non-pumped hydroelectric facilities within a load area cannot exceed the load area's total turbine capacity, de-rated by the forced outage rate for hydroelectric generators.

$HYDRO\_MIN\_DISP_{h,t}$	For every non-pumped hydroelectric project *h* in every hour *t*, the amount of energy $H_{h,t}$ dispatched by the non-pumped hydroelectric project must be greater than or equal to a pre-specified average flow rate for that project on

$H_{h,t} \geq ah_{h,m_t} \cdot mf$	the day of that hour, $ah_{h,m}$, times a pre-specified minimum dispatch fraction, *mf*, necessary to maintain stream flow.

HYDRO_MAX_DISP$_{h,t}$ $H_{h,t} + OP_{h,t} \leq (1 - o_h) \cdot hg_h$	For every non-pumped hydroelectric project *h* in every hour *t*, the amount of energy $H_{h,t}$ and operating reserve $OP_{h,t}$ dispatched by the non-pumped hydroelectric project *h* cannot exceed the project's capacity, hg_h de-rated by the hydroelectric project's forced outage rate o_h.

HYDRO_MAX_RESERVE$_{h,t}$ $OP_{h,t} \leq hydro\_op\_fraction \cdot hg_h$	For every hydroelectric project *h* in every hour *t*, the amount of operating reserve $OP_{h,t}$ dispatched cannot exceed a fraction *hydro_op_fraction* of the project's capacity, hg_h.

PUMPED_HYDRO_MAX_DISP$_{p,t}$ $PH_{p,t} + \sum_f PHD_{p,t,f} + OP_{p,t} \leq (1 - o_p) \cdot pg_p$	For pumped hydroelectric project *p* and every hour *t*, the sum of watershed energy, $PH_{p,t,f}$, dispatched stored energy, $PHD_{p,t,f}$, from all fuel categories *f*, and operating reserve $OP_{p,t}$ cannot exceed the pre-specified capacity of the pumped hydroelectric project, pg_p, de-rated by the pumped hydroelectric project's forced outage rate o_p.

5. The amount of energy produced from all hydroelectric facilities in a load area over the course of each study day must equal the historical average energy production for the month in which that day resides.

HYDRO_AVG_OUTPUT$_{h,t}$ $\sum_{t \in T_d} H_{h,t} = \sum_{t \in T_d} ah_{h,m_t}$	For every non-pumped hydroelectric project *h* and every day *d*, the historical monthly average flow must be met, i.e. the sum over all hours on day *d* of energy, $H_{h,t,}$ dispatched by the non-pumped hydroelectric project *p* must equal a pre-specified average daily level $ah_{h,m}$ for that month. T_d is the set of hours on day *d*.

PUMPED_HYDRO_AVG_WATERSHED$_{p,d}$ $\sum_{t \in T_d} PH_{p,t} = \sum_{t \in T_d} ah_{h,m_t}$	For every pumped hydroelectric project p and every day d, $PH_{p,t,f}$, the total watershed energy released by the pumped-hydroelectric project, must equal a pre-specified average daily level $ah_{h,m}$, for that month. T_d is the set of hours on day d.

6. A storage project can store no more power in each hour than its maximum hourly store rate, de-rated by its forced outage rate, and dispatch no more power in each hour than its capacity, de-rated by its forced outage rate. Compressed Air Energy Storage (CAES) projects must maintain the proper ratio between energy stored in the form of compressed air and energy dispatched in the form of natural gas.

MAX_STORAGE_RATE$_{s,t}$ $\sum_f S_{s,t,f} \le (1 - o_s) \cdot r_s \cdot \sum_i SG_{s,i}$	For every storage project s in every hour t, the expected amount of energy, $S_{s,t,f}$, stored at the storage project s in hour t from each fuel type f cannot exceed the product of a pre-specified store rate for that project, r_s, and the total capacity $SG_{s,t,f}$ installed at project s in the current and preceding periods i, de-rated by the storage project's forced outage rate o_s. The operational storage project lifetime limits the extent of the sum over i to only periods in which the storage project would still be operational.

MAX_STORAGE _DISPATCH$_{s \neq CAES,t}$ $\sum_f R_{s,t,f} + OP_{s,t} \le (1 - o_s) \cdot \sum_i SG_{s,i}$	For every non-CAES storage project s in every hour t, the expected amount of energy dispatched from the storage project in that hour from all fuel types f, $R_{s,t,f}$, plus the operating reserve provided $OP_{s,t}$ in that hour cannot exceed the sum, de-rated by the storage project's forced outage rate o_s, of the storage project power capacity $SG_{s,i}$ installed in the current and preceding periods i. The operational storage project lifetime limits the extent of the sum over i to only periods in which the storage project would still be operational.

MAX_CAES _DISPATCH$_{s=CAES,t}$ $\sum_f R_{s,t,f} + C_{s,t} + SP_{s,t} + Q_{s,t} + OP_{s,t}$ $\le (1 - o_s) \cdot \sum_i SG_{s,i}$	For every CAES storage project s in every hour t, the sum of the energy dispatched from all fuel types f, $R_{s,t,f}$, and the operating reserve $OP_{s,t}$ provided by the storage plant plus the energy dispatched $C_{s,t}$, spinning reserve $SP_{s,t}$ and quickstart reserve $Q_{s,t}$ provided from natural gas cannot exceed the sum, de-rated by the plant's forced outage

	rate o_s, of the plant's total power capacity $SG_{s,i}$ installed in the current and preceding periods i. The operational CAES project lifetime limits the extent of the sum over i to only periods in which the CAES project would still be operational.

CAES_COMBINED_DISPATCH$_{s=CAES,t}$ $\sum_f R_{s,t,f} = C_{s,t} \cdot caes\_ratio$	For every CAES project s in every hour t, the amount of energy dispatched from the CAES project in that hour from all fuel types f, $R_{s,t,f}$, must equal the amount of energy dispatched from natural gas $C_{s,t}$ multiplied by the dispatch ratio between storage and natural gas *caes_ratio*.

CAES_COMBINED_OR$_{s=CAES,t}$ $OR_{s,t} = (SP_{s,t} + Q_{s,t}) \cdot caes\_ratio$	For every CAES project s in every hour t, the amount of operating reserve dispatched from the CAES project in that hour must equal the operating reserve (spinning plus quickstart) dispatched from natural gas ($SP_{s,t}+ Q_{s,t}$) multiplied by the dispatch ratio between storage and natural gas *caes_ratio*.

PUMPED_HYDRO_MAX_STORE$_{p,t}$ $\sum_f PHS_{p,t,f} \leq pg_p \cdot (1-o_p)$	For every hour t, the energy stored by a pumped hydroelectric project p, $PHS_{p,t,f}$, cannot exceed the pre-specified capacity of the hydroelectric project, de-rated for the project's forced outage rate o_p.

7. Because days are modeled as independent dispatch units, the energy dispatched by each storage project each day must equal the energy stored by the project on that day, adjusted for the storage project's round-trip efficiency losses.

STORAGE_ENERGY_BALANCE_BY_FUEL_CATEGORY$_{s,d,f}$ $\sum_{t \in T_d} R_{s,t,f} = \sum_{t \in T_d} S_{s,t,f} \cdot e_s$	For each storage project s and each fuel category f on each day d, the energy from fuel category f dispatched by the storage project in all hours t on day d 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_s.

STORAGE_ENERGY_BALANCE$_{s,d}$ $$\sum_{t \in T_d} R_{s,t} + op_fraction \cdot \sum_{t \in T_d} OR_{s,t} = \sum_{t \in T_d} S_{s,t} \cdot e_s$$	For each storage project *s* on each day *d*, the energy dispatched by the storage project in all hours *t* on day *d* 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_s. It is assumed that operating reserve is called upon to produce energy a fraction of the time, *op_fraction*, and this is included in the energy balance. T_d is the set of hours on day *d*.

PUMPED_HYDRO_ENERGY_BALANCE_BY_FUEL_CATEGORY$_{p,d,f}$ $$\sum_{t \in T_d} PHD_{p,t,f} = \sum_{t \in T_d} PHS_{p,t,f} \cdot pe$$	For every pumped hydroelectric project *p*, every day *d*, and every fuel category, $PHD_{p,t,f}$, the total amount of energy from fuel type *f* dispatched by the project in all hours *t* on day *d*, must equal $PHS_{p,t,f}$, the total amount of energy from fuel type f stored by the hydroelectric project in all hours t on day d, times a pre-specified pumped hydroelectric storage efficiency, *pe*. T_d is the set of hours on day *d*.

PUMPED_HYDRO_ENERGY_BALANCE$_{p,d}$ $$\sum_{t \in T_d} PHD_{p,t,f} + op_fraction \cdot \sum_{t \in T_d} OP_{p,t,f} = \sum_{t \in T_d} PHS_{p,t,f} \cdot pe$$	For every pumped hydroelectric project *p*, every day *d*, the total amount of energy $PHD_{p,t}$ dispatched by the hydroelectric project in all hours *t* on day *d*, must equal $PHS_{p,t,f}$, the total amount of energy stored by the hydroelectric project in all hours t on day d, times a pre-specified pumped hydroelectric storage efficiency, *pe*. It is assumed that operating reserve is dispatched a fraction of the time, *op_fraction*, and this is included in the energy balance.

	T_d is the set of hours on day d.

8. The amount of power transferred in each direction through transmission lines in each hour between each pair of connected load areas can be no more than the line's rated capacity, de-rated by its forced outage rate. Once a transmission line is installed, it is assumed to remain in operation for the remainder of the study.

MAX_TRANS$_{a,a1,t}$ $\sum_{f} Tr_{a,a',t,f} \leq (1 - o_{a,a'}) \cdot (et_{a,a'} + \sum_{i} T_{a,a',i})$	For each transmission line *(a, a')* in every hour *t*, the total amount of energy, $Tr_{a,a',t,f}$ from all fuel types *f* dispatched along the transmission line between load areas *a* and *a'* in each hour *t* cannot exceed the sum, de-rated by the transmission line's forced outage rate $o_{(a,a')}$, of the pre-existing transfer capacity $et_{(a,a')}$ and the sum of additional capacities $T_{a,a',i}$ installed between the two load areas in the current and all preceding periods *i*.

9. The total amount of power exported from the Mexican load area of Baja California Norte in each investment period cannot grow at more than of the historical electric power export growth rate between 2003 and 2008 of 3.2 %/yr (Secretaría de Energía 2010). This constraint ensures that Mexico can export power to United States load areas, but restricts the growth of exports to realistic levels.

MEX_EXPORT_LIMIT$_{a=MEX\_BAJA,i}$ $\sum_{a', t \in T_i, f} Tr_{a,a',t,f} \cdot hs_t - \sum_{a'', t \in T_i, f} Tr_{a'',a,t,f} \cdot hs_t \leq mexptlim_i$	For each investment period *i*, the sum of transmission capacity $Tr_{a,a',t,f}$ dispatched out of the load area *a=MEX_BAJA*, minus the sum of transmission capacity $Tr_{a'',a,t,f}$ dispatched into the load area *a=MEX_BAJA*, weighted by the number of sample hours hs_t represented by timepoint *t*, cannot exceed the specified export limit out of MEX_BAJA $mexptlim_i$.

10. The total expected supply of power from generation, storage, and transmission in each load area during each hour must equal or exceed the amount of power consumed in that load area and at that time. The total supply of power can exceed the demand for power to reflect the potential of spilling power or curtailment during certain hours.

CONSERVATION_OF_ENERGY_NON_DISTRIBUTED$_{a,t,f}$ $NP_{a,t,f} \cdot (1+dl) \leq$		For every load area a, in each hour t, and for every fuel category f, the amount of non-distributed energy $NP_{a,t,f}$ consumed in the load area in that hour plus any distribution losses dl cannot exceed
Generation	$\sum_{vn \in VN_a} VN_{vn,t,f} + \sum_{c \in C_a} C_{c,t,f} + \sum_{b \in B_a} B_{b,t,f} + \sum_{h \in H_a} H_{h,t,f} +$	the total power generated in load area a in hour t by all intermittent non-distributed projects ($VN_{vn,t,f}$), all baseload projects ($B_{b,t,f}$), all dispatchable projects ($C_{c,t,f}$), and all non-pumped hydroelectric generators ($H_{h,t,f}$)
Transmission	$+\sum_{a,a'} Tr_{a,a',t,f} \cdot e_{a,a'} - \sum_{a'',a} Tr_{a'',a} +$	plus the total power supplied to load area a from other load areas a' via transmission, de-rated for the line's transmission efficiency, $e_{a,a'}$, minus the total power exported from load area a to other load areas a'' via transmission
Storage	$+\sum_{s \in S_a} R_{s,t,f} - \sum_{s \in S_a} S_{s,t,f} +$	plus the total energy, $R_{s,t,f}$, supplied to load area a in hour t by storage projects s minus the total energy, $S_{s,t,f}$, that is stored by storage projects s
Pumped Hydroelectric	$+\sum_{p \in P_a} PH_{p,t,f} + \sum_{p \in P_a} PHD_{p,t,f} - \sum_{p \in P_a} PHS_{p,t,f}$	plus the total power generated from pumped hydroelectric watershed energy, $PH_{p,a,t}$, and the total power dispatched from pumped hydroelectric storage, $PHD_{p,a,t,f}$, that is supplied to load area a in hour t by all pumped hydroelectric projects p, minus the total power, $PHS_{p,a,t,f}$, that is stored by pumped hydroelectric projects p in load area a in hour t.

Redirected	$+DR_{a,t,f}$	plus distributed energy , $DR_{a,t,f}$, that is exported through the distribution system to the transmission grid.

CONSERVATION_OF_ENERGY_DISTRIBUTED$_{a,t,f}$ $DP_{a,t,f} + DR_{a,t,f} \cdot (1+dl) \geq \sum_{vd \in VD_{a,f}} VD_{vd,t}$	In every load area *a*, in each hour *t*, and for every fuel category *f*, the amount of distributed energy $DP_{a,t,f}$ consumed in the load area plus any distributed power, $DR_{a,t,f}$, that is exported through the distribution system, adjusted for distribution losses *dl*, cannot exceed the total distributed generation available in load area *a* in hour *t*.

SATISFY_LOAD$_{a,t}$ $\sum_{f} (NP_{a,t,f} + DP_{a,t,f}) = l_{a,t}$	For every load area *a* in each hour *t*, the total energy consumed from distributed and non-distributed sources must equal the pre-defined system load $l_{a,t}$.

6.2. Reserve-Margin constraints

Power plants and transmission lines can experience outages and various mechanical failures, To address system risk, the model requires that enough power plant and transmission capacity be built to provide a 15% capacity reserve margin above load in each load area in all hours.

1. The total supply of reserve capacity in each load area during each hour must equal or exceed 115% of the power demand in each load area and in each study hour.

CONSERVATION_OF_ENERGY_NON_DISTRIBUTED_RESERVE$_{a,t}$ $NPR_{a,t} \cdot (1+dl) \leq$	In every load area *a*, in each hour *t*, the amount of non-distributed capacity $NPR_{a,f}$ available to meet the capacity reserve margin in the load area in that hour plus any distribution losses *dl* cannot exceed

Generation Capacity	$$\sum_{vn \in VN_a} (cf_{vn,t} \cdot \sum_i VNG_{vn,i}) + \sum_{c \in C_a} \sum_i CG_{c,i} + \sum_{b \in B_a} \sum_i BG_{b,i} \cdot (1 - s_b)$$	the total capacity of all intermittent non-distributed projects ($VNG_{vn,i}$) multiplied by their capacity factor $cf_{vn,t}$ in hour t, plus the total capacity of all dispatchable projects ($CG_{c,i}$), plus the total capacity, adjusted for scheduled outage rate s_b, of all baseload projects ($B_{b,i}$) in load area *a* in hour *t*,
Transmission Capacity	$$+\sum_{a,a'} \sum_f Tr_{a,a',t,f} \cdot e_{a,a'} - \sum_{a'',a} \sum_f Tr_{a'',a,t,f}$$	plus the total power transmitted to load area *a* from other load areas *a'* ($Tr_{a,a',t,f}$), de-rated for the line's transmission efficiency, $e_{a,a'}$, minus the total power transmitted from load area *a* to other load areas *a''* ($Tr_{a'',a,t,f}$)
Storage Capacity	$$+\sum_{s \in S_a} \sum_f R_{s,t,f} - \sum_{s \in S_a} \sum_f S_{s,t,f}$$	plus the total output $R_{s,t,f}$, of storage projects *s* in load area *a* in hour *t* minus the energy stored, $S_{s,t,f}$, by storage projects *s* in load area *a* in hour *t*
Hydroelectric and Pumped Hydroelectric Capacity	$$+\sum_{h \in H_a} H_{h,t} + \sum_{p \in P_a} PH_{p,t} + \sum_{p \in P_a} \sum_f PHD_{p,t,f} - \sum_{p \in P_a} \sum_f PHS_{p,t,f}$$	plus the total non-pumped hydroelectric ($H_{h,t}$) and pumped hydroelectric ($PHR_{p,a,t}$) watershed power supplied, and the total pumped hydroelectric stored power, $PHD_{p,a,t,f}$, supplied to load area *a* in hour *t* by all pumped hydroelectric projects *p* minus the total energy, $PHS_{p,a,t,f}$, that is stored by pumped hydroelectric projects *p*.
Redirected	$$+DRR_{a,t}$$	plus the distributed capacity, $DRR_{a,t}$, that is available to be exported through the distribution system.

$CONSERVATION\_OF\_ENERGY\_DISTRIBUTED\_RESERVE_{a,t,f}$ $$DPR_{a,t} + DRR_{a,t} \cdot (1 + dl) \geq \sum_{vn \in VN_a} (cf_{vd,t} \cdot \sum_i VDG_{vd,i})$$	In every load area *a*, in each hour *t*, the amount of distributed energy $DPR_{a,t}$ consumed in the load area plus any distributed power, $DRR_{a,t}$, adjusted for distribution losses *dl*, that is exported through the distribution system cannot exceed the total distributed generation

	capacity available in load area *a* in hour *t*.

SATISFY_RESERVE_MARGIN$_{a,t}$ $DPR_{a,t} + NPR_{a,t} =$ $(1+r) \cdot l_{a,t}$	For each load area *a*, in each hour *t*, the total distributed and non-distributed capacity available for consumption must equal the pre-defined system load $l_{a,t}$ for that load area for that hour plus a pre-specified reserve margin *r*.

6.4. Operating Reserve Constraints

SATISFY_SPINNING_RESERVE$_{ba,t}$ $\sum_{c \in C_{ba}} SP_{c,t} + \sum_{g \in S_{ba} \cup H_{ba} \cup P_{ba}} OP_{g,t}$ $\geq spinning\_reserve\_reqt_{ba,t}$	In each balancing area *ba* in each hour *t*, the spinning reserve provided by dispatchable plants, $SP_{c,t}$, plus the operating reserve $OP_{g,t}$ provided by storage plants ($g \in S_a$), hydroelectric plants ($g \in H_a$), and pumped hydroelectric storage plants ($g \in P_a$) must equal or exceed the spinning reserve requirement in that balancing area in that hour. The spinning reserve requirement is calculated as a percentage of load plus a percentage of intermittent generation in each balancing area in each hour.

SATISFY_OPERATING_RESERVE$_{ba,t}$ $\sum_{c \in C_{ba}} SP_{c,t} + \sum_{c \in C_{ba}} Q_{c,t} + \sum_{g \in S_{ba} \cup H_{ba} \cup P_{ba}} OP_{g,t}$ $\geq operating\_reserve\_reqt_{ba,t}$	In each balancing area *ba* in each hour *t*, the spinning reserve provided by dispatchable plants, $SP_{c,t}$, plus the quickstart reserve provided by dispatchable plants, $Q_{c,t}$, plus the operating reserve $OP_{g,t}$ provided by storage plants ($g \in S_a$), hydroelectric plants ($g \in H_a$), and pumped hydroelectric storage plants ($g \in P_a$) must equal or exceed the total operating reserve requirement (spinning plus quickstart) in that balancing area in that hour. The operating reserve requirement is calculated as a percentage of load plus a percentage of intermittent generation in each balancing area in each hour.

6.5. RPS Constraint

This constraint requires that, for each load-serving entity and for every period, the percentage of total consumed power delivered by qualifying renewable sources is greater than or equal to the fraction specified by existing RPS targets. The RPS constraint does not allow the use of unbundled, tradable Renewable Energy Credits (RECs).

MEET_RPS$_{lse,i}$ $$\frac{\sum_{t\in T_i, f\in R, a\subset A_{lse}} (DP_{a,t,f} + NP_{a,t,f}) \cdot hs_t}{\sum_{t\in T_i, a\subset A_{lse}} l_{a,t} \cdot hs_t} \geq rps_{lse,i}$$	For every load-serving entity *lse* in every period *i*, the proportion of the total power consumed in all hours of that period (the set T_i) from all RPS-eligible fuels (the set *R*) must be greater than or equal to the pre-defined RPS fraction, $rps_{lse,i}$, for that load area for that period. Each timepoint in the set T_i is weighted by the number of sample hours it represents, hs_t.

6.5. Carbon Cap Constraint

This constraint requires that, for every period, the total carbon dioxide emissions from generation and spinning reserve provision cannot exceed a pre-specified emissions cap.

CARBON_CAP$_i$ $$\sum_{g,t\in T_i} O_{g,t} \cdot hr_g \cdot co2\_fuel_g + \sum_{c,t\in T_i} SP_{c,t} \cdot hr\_penalty_g \cdot co2\_fuel_g \leq carbon\_cap_i$$	In every period *i*, the total carbon emissions from generation (calculated as the plant output $O_{g,t}$ times the plant heat rate hr_g times the carbon dioxide fuel content for that plant) plus the carbon emissions from spinning reserve (calculated as the plant output $O_{g,t}$ times the plant per unit heat rate penalty for providing spinning reserve $hr\_penalty_g$ times the carbon dioxide fuel content for that plant) cannot exceed a pre-specified carbon cap $carbon\_cap_i$ for that period.

<u>Data Description</u>

1. Load Areas: Geospatial Definition

The model divides the geographic region of WECC into 50 load areas. These areas represent sections of the grid within which there is significant existing local transmission and distribution, but between which there is limited long range, high-voltage existing transmission. Consequently, load areas are areas between which transmission investment may be beneficial.

Load areas are predominantly divided 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 much 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 currently congested transmission corridors as possible (Western Electricity Coordinating Council 2009). These pathways are some of the first places that transmission is likely to be built, and exclusion of these pathways in definition of load areas would allow power to flow without penalty along overloaded transmission lines.

2. Cost Regionalization

Costs for constructing and operating generation and transmission vary significantly 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) (United States Department of Labor 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.

Data for Canadian and Mexican economic multipliers are estimated and will be updated in future versions of the model.

3. Transmission Lines

The existing transmission capacity between load areas is found by matching geolocated Ventyx data (Ventyx EV Energy Map) with Federal Energy Regulatory Commission (FERC) data on the thermal limits of individual power lines (Federal Energy Regulatory Commission 2009). A small fraction of lines present in the Ventyx database could not be matched to lines found in the FERC database; these lines are ascribed a generic transfer capacity equal to the average transfer capacity of their voltage class. In total, 104 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 distances along existing transmission lines between these substations. If no existing path is present, new transmission can be installed between adjacent load areas assuming a distance of 1.5 the distance between largest capacity substations of the two load areas.

The amount of power that can be transferred along each transmission line is set at the rated thermal limits of individual transmission lines. Additionally, transmission power losses are taken into account at 1 percent of power is lost for every 100 miles over which it is transmitted, with an upper limit of 98.5 % efficiency between any pair of load areas.

4. Local T&D and Transmission Costs

The costs for existing transmission and distribution are derived from the regional electricity tables of the United States Energy Information Agency's 2010 Annual Energy Outlook (United States Energy Information Agency 2010a). The $/MWh cost incurred in 2010 for each NERC subregion is apportioned by present day average load to each load area and is then assumed to be a sunk cost over the whole period of study. All existing transmission and distribution capacity is therefore implicitly assumed to be kept operational indefinitely, incurring concomitant operational costs.

It is further assumed that the distribution network is built to serve the peak load of 2011, and that in future investment periods this equivalence must be maintained. Investment in new local transmission and distribution is therefore a sunk cost as projected loads are exogenously calculated.

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. In the case of surplus distributed generation, the model can send power from distributed generators out to other load areas, incurring a 5.3% power loss on the way out. This loss is in addition to subsequent transmission, storage and distribution losses, so power sent in this manner will incur distribution losses twice.

5. Load Profiles

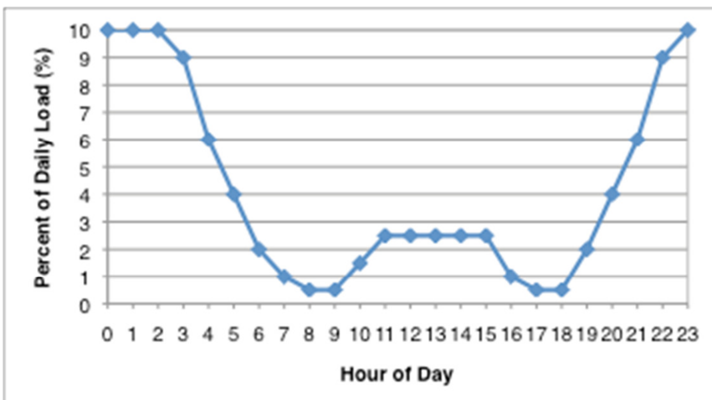
Planning Area hourly loads from the Federal Energy Regulatory Commission's (FERC) Annual Electric Balancing Authority Area and Planning Area Report (FERC Form 714) (Federal Energy Regulatory Commission 2006) are partitioned into SWITCH load areas by manually matching substations owned by each planning area to georeferenced substations (Platts Corporation 2009). As not all substations match between the two datasets, a map of each planning area is created by drawing boundaries around each of the substation areas. Existing geospatial layers of planning areas from Platts (Platts Corporation 2009) and Ventyx (Ventyx EV Energy Map) do not provide enough data to be used exclusively in this process because of overlapping territories, changes in planning areas over time, and the complexity of the electric power system at the distribution level. Rather, these planning area layers serve only as a guide to forming maps of planning area loads.

Many load areas are comprised of encompass single planning areas; for these regions, the planning area hourly load is used as the load 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. Finally, as the planning areas PacificCorp and Bonneville Power Administration span the Western and Central time zones but report a single hourly load, loads from areas located within these LSEs but in a different time zone from the reported load are shifted one hour to reflect the difference in timing of loads as a function of the hour of day.

Load on each hour in the model corresponds to the observed load on one historical hour from the year 2006. These hourly loads are then shaped using hourly load profiles for energy efficiency, electrification of heating, and electric vehicles. The magnitude of load added (or subtracted in the case of energy efficiency) to the 2006 load profile is dictated by electricity load projections discussed in the body of this report.

Hourly California load projections for energy efficiency and electrification of heating from present day to 2050 from were obtained from Itron. These projections are made for each California forecast climate zone and are divided into load areas via the population fraction of each climate zone in each load area. For load areas outside California, the load profiles across all of California for energy efficiency and electrification of heating were used to shape demand. California load profiles were time-shifted by one hour for load areas in Mountain time to reflect dependence on the hour of day. In addition, as the adoption of heating electrification is assumed to occur ten years later in the rest of WECC than it does in California, the California heating electrification load profile was shifted ten years back when applied to load areas outside California.

Hourly electric vehicle loads are created from a daily charging profile shown below provided by UC Davis and scaled to projected demands. Historical monthly demand is also used to shape the magnitude of electric vehicle demand in each month.



Appendix Figure 1: *Electric Vehicle daily charging profile.*

6. Renewable Portfolio Standards

State-based Renewable Portfolio Standards (RPS) specify that a certain fraction of electricity consumed within a Load Serving Entity (LSE) that must be produced by qualified renewable generators. Targets follow a yearly schedule, increasing from low levels presently higher levels by the mid 2020s (North Carolina State University 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 area for the percentage of load that must be met by *delivered renewable* 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.

Delivered power is power that is either generated within a load area and consumed immediately, or added to the power mix of the load area via transmission or storage, after accounting for efficiency losses. Power lost during distribution is not counted towards RPS targets. To ensure proper accounting, the stocks and flows of qualifying power is kept separate from non-qualifying power.

While most load areas are fully contained within a single LSE and a single state, targets for those load areas that span LSE and/or state lines are calculated as a weighted sum of the RPS goals on the two sides of the LSE and/or state border, with the weights based on the relative population levels within each load area within each LSE and/or state. RPS targets are averaged over each period for each load area. Canadian and Mexican load areas do not have RPS targets.

7. Fuel Prices

Coal, natural gas and fuel oil fuel price projections for electric power generation originate from the reference case of the United States Energy Information Agency's 2011 Annual Energy Outlook (United States Energy Information Agency 2011). These yearly projections are made for each North American Electric Reliability Corporation (NERC) subregion through 2035, and are extrapolated for years after 2035. Yearly fuel price projections are averaged over each study period. 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, natural gas and fuel oil prices are assumed to be the same as the prices in the nearest United States NERC subregion. Fuel price elasticity is not currently included.

Uranium price projections are taken from the California Energy Commission's 2007 Cost of Generation Model (Klein 2007). These prices apply to all load areas as uranium has less regional price variation than other fuels.

Solid biomass fuel costs are discussed directly below.

8. Biomass Supply Curve

Fuel costs for solid biomass are input into the 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 a variety of sources listed in the table below. This table does not represent the technical potential of recoverable solid biomass – instead it depicts the economically recoverable quantity of biomass solid feedstock. 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. Feedstock prices range between \$0.2/MMBtu and \$13.3/MMBtu (in \$2007), with a quantity-weighted average price across WECC of \$2.7/MMBtu. While the energy content per BDT of biomass varies by feedstock, a factor of 15 MMBtu/BDT can be used for rough conversion between BDT and MMBtu. Note that, following standard biomass unit definitions, 1 MMBtu = 10^6 Btu.

Biomass Feedstock Type	California Availability [10^{12} Btu/Yr]	Rest of WECC Availability [10^{12} Btu/Yr]	California Availability [10^{12} BDT/Yr]	Rest of WECC Availability [10^{12} BDT/Yr]	Sources
Corn Stover	19.1	82.3	1.35	5.83	1
Forest Residue	41.3	408.8	2.74	27.13	1, 4
Forest Thinning	72.3	211.0	4.80	14.00	1
Mill Residue + Pulpwood	39.5	254.3	2.62	16.87	2, 3, 4
Municipal Solid Waste (MSW)	81.4	117.1	4.93	7.10	2, 4
Orchard and Vineyard Waste	66.1	10.5	4.39	0.70	2
Switchgrass	0	123.7	0	8.43	1, 4
Wheat Straw	8.1	70.0	0.60	5.16	1
Agricultural Residues (Canada Data Only)	0	183.2	0	13.51	4
Total	**327.8**	**1460.9**	**21.43**	**98.73**	

Appendix Table 1: *Biomass Supply in the SWITCH model for years 2030 and beyond. Sources: 1: de la Torre Ugarte 2000; University of Tennessee 2007; 2: Parker 2011; 3: Milbrandt 2005; 4: Kumarappan 2009 (Canada Data Only).*

9. Existing Generators

9.1. Existing Generator Data

Existing generators within the United States portion of WECC are geolocated into load areas using Ventyx EV Energy Map (Ventyx EV Energy Map 2009). Generators found in the United States Energy Information Agency's Annual Electric Generator Report (United States Energy Information Agency 2007a) 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 (Western Electricity Coordinating Council 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 synthetic crude oil, solar thermal, and solar photovoltaic generators, as well as biomass co-firing units on existing coal plants are not included in the current version of the model. These generators constitute less than 2% of the existing generating capacity in WECC.

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 Agency's Form 906 (United States Energy Information Agency 2007b). 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 (Western Electricity Coordinating Council 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 coal and hydroelectric generators originate from present day costs found in the United States Energy Information Agency's Updated Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010a). Costs for non-coal, non-hydroelectric generators originate from the California Energy Commission's Cost of Generation Model (California Energy Commission 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.

Existing plants are not allowed to operate past their expected lifetime with the exception of nuclear plants, which are given the choice to continue plant operation by paying all operational costs in investment periods past the expected lifetime of the plant in question.

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.

9.2. Existing Hydroelectric and Pumped Hydroelectric Plants

Hydroelectric and pumped hydroelectric generators include constraints derived from historical monthly generation data from 2006. For non-pumped hydroelectric generators in the United States, monthly net generation data from the United States Energy Information Agency's Form 906 (United States Energy Information Agency 2007b) is employed. The profile of Washington and Montana monthly net generation data is used to shape British Columbia and Albertan hydroelectric generation, respectively. Hydroelectric and pumped hydroelectric generators are aggregated to the load area level in order to reduce the number of decision variables.

For pumped hydroelectric generators, the use of net generation data is not sufficient, as it 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 (United States Energy Information Agency 2007b) is used to correct this factor. By assuming a 74% round-trip efficiency (Electricity Storage Association 2010) and that monthly in-stream flows for pumped hydroelectric projects are 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 EV Energy Map 2009).

New hydroelectric facilities are not built in the current version of the model. The high capital cost of these generators, especially pumped storage, would likely preclude installation.

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 capacity, number of turbines, and installation year of each wind farm in the United States that currently exists or is under construction is obtained from the American Wind Energy Association (AWEA) wind plant dataset (American Wind Energy Association 2010). The total existing wind farm capacity in WECC is 10 GW. Wind farms are geolocated by matching wind farms in the AWEA dataset with wind farms in the Ventyx EV Energy Map dataset (Ventyx EV Energy Map 2009). Existing Canadian wind farms are not currently included in the model. At present, the Mexican portion of WECC does not have operational utility-scale wind turbines (The Wind Power 2010).

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 from 'The Wind Power' wind turbines and wind farms database (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 2004). 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.

10. New Generators

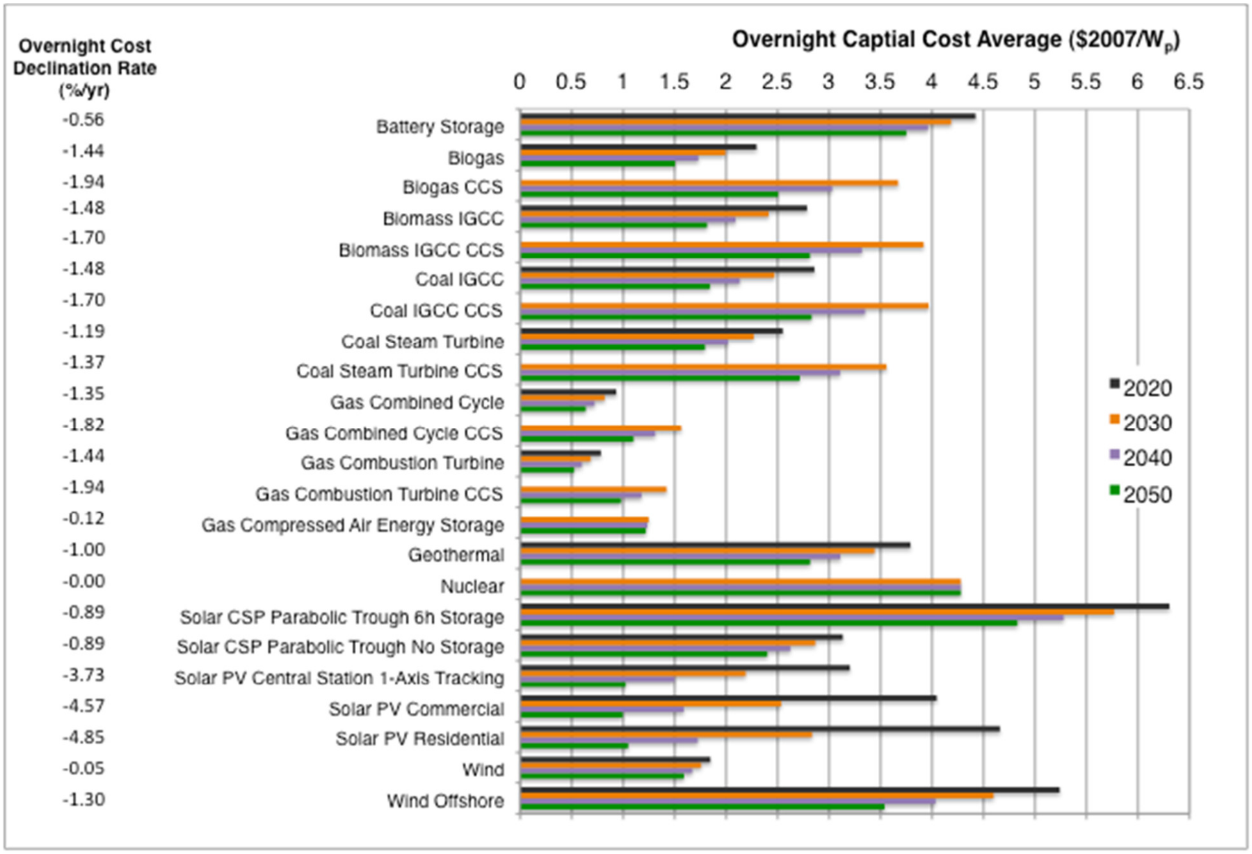
10.1. Capital and O&M Costs

The present day capital costs and operation and maintenance (O&M) costs for each power plant type originate primarily from the California Energy Commission Cost of Generation Model (California Energy Commission 2010). Present day costs for coal and carbon capture and sequestration generation originate from the United States Energy Information Agency's Updated

Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010b). Costs for photovoltaic generators originate from the National Renewable Energy Laboratory's Solar Vision Study (United States Department of Energy 2010). Captial costs in SWITCH decrease over time via exponential decay using decay rates derived from (Black & Veatch 2010). O&M costs are assumed to remain constant over time.

Fuel	Technology	Overnight Cost in 2011 [$2007/W]	Overnight Cost Change [%/yr]	Fixed O&M [$2007/MW*yr]	Variable O&M [$2007/MWh]	Efficiency [%]	Carbon Emissions [tCO_2/MWh]
Bio Gas	Bio Gas	2.28	-1.44	114000	0.01	25	0
Bio Gas CCS	Bio Gas CCS	4.17	-1.94	156000	13.77	18.9	-1.633
Bio Solid	Biomass IGCC	2.7	-1.48	140000	3.71	32.5	0
Bio Solid CCS	Biomass IGCC CCS	4.61	-1.70	158000	5	26.4	-1.036
Coal	Coal Steam Turbine	2.57	-1.19	27000	3.89	38.8	0.841
Coal	Coal IGCC	2.91	-1.48	45000	6.29	39.2	0.831
Coal CCS	Coal Steam Turbine CCS	4.14	-1.37	58000	8.29	28.4	0.172
Coal CCS	Coal IGCC CCS	4.82	-1.70	63000	7.37	31.9	0.153
Gas	Gas Combustion Turbine	0.75	-1.35	15000	3.4	39.9	0.454
Gas	Compressed Air Energy Storage	1.1	-0.12	9000	2.84	77.6*	0.233
Gas	CCGT	0.9	-1.35	7000	2.46	52.8	0.343
Gas CCS	CCGT CCS	1.85	-1.82	28000	5.73	45.4	0.06
Gas CCS	Gas Combustion Turbine CCS	1.7	-1.94	36000	7.71	34.3	0.079
Geothermal	Geothermal	3.69	-1.00	44000	3.17		0
Solar	Central PV	3.63	-3.73	10000	0		0
Solar	Commercial PV	4.53	-4.57	10000	0		0
Solar	CSP Trough 6h Storage	5.74	-0.89	63000	0		0
Solar	Residential PV	5.27	-4.85	10000	0		0
Solar	CSP Trough No Storage	3.37	-0.89	63000	0		0
Storage	Battery Storage	4.11	-0.56	26000	0.52		0
Uranium	Nuclear	3.67	0.00	137000	4.82	32.8	0
Wind	Offshore Wind	5.06	-1.30	25000	9.47		0
Wind	Wind	1.83	-0.05	13000	4.73		0

Appendix Table 2: *New generator costs, heat rates and outage rates. The base overnight cost shown here represents the overnight cost incurred when starting construction in 2011. *The efficiency of Compressed Air Energy Storage quoted here contains only the natural gas part of energy generation – energy from the compressed air in the storage cavern is also needed, lowering the total efficiency.*



Appendix Figure 2: *Average generator and storage overnight capital costs in each investment period. Plants not eligible for construction in the 2020 investment period are excluded from this chart. The costs shown do not include expenses related to project development such as interest during construction, connection costs to the grid and upgrades to the local grid, though these costs are included in each optimization.*

10.2. Connection Costs

The cost to connect new generators to the existing electricity grid is derived from the United States Energy Information Agency's 2007 Annual Electric Generator Report (United States Energy Information Agency 2007a). Connection costs for different technologies are shown in Supplemental Table 4 below.

The generic connection cost category applies to projects that *are not* sited at specific geographic locations in SWITCH. For these projects, it is assumed that it is possible to find a project 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 to connect generators to the grid without a large transmission line was $91,289 per MW (United States Energy Information Agency 2007a). Substation installation or upgrade and grid enhancement costs that are incurred by adding the generator to the grid account for $65,639 per MW of the total connection cost. Constructing a small transmission line to the existing grid accounts for $25,650 per MW of the total connection cost.

The site-specific connection cost category applies to projects that *are* sited in specific geographic locations but are not considered distributed generation in SWITCH. 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 $1,000 per MW per km, the same as to the assumed cost of building transmission between load areas. Underwater transmission for offshore wind projects is assumed to be five times this cost, $5000 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.

Generic	Site Specific	Distributed
$91,289/MW ($2007)	$65,639/MW ($2007)	$0/MW ($2007)
No Additional Transmission	Additional Distance-Specific Transmission Costs Incurred	Interconnection Included In Capital Cost
Nuclear	Wind	Residential Photovoltaic
Gas Combined Cycle	Offshore Wind	Commercial Photovoltaic
Gas Combustion Turbine	Central Station Photovoltaic	
Coal Steam Turbine	Solar Thermal Trough, No Thermal Storage	
Coal Integrated Gasification Combined Cycle	Solar Thermal Trough, 6h Thermal Storage	
Biomass Integrated Gasification Combined Cycle		
Biogas		
Battery Storage		
Compressed Air Energy Storage		

Appendix Table 3: *Connection Cost Types in SWITCH. 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 distributed connection cost category currently applies only to residential and commercial photovoltaic projects. For these projects, the interconnection costs are included in project capital costs and are therefore not explicitly specified in other parts of the model.

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

10.3. Non-Renewable Thermal Generators

10.3.1. Non-Renewable Non-CCS Thermal Generators

Nuclear steam turbines, coal steam turbines, and coal integrated gasification combined cycle plants (Coal IGCC) are modeled as baseload technologies. Their output remains constant in every study hour, de-rated by their forced and scheduled outage rates. These technologies are assumed to be buildable in any load area, which the exception of California load areas due to legal build restrictions on new nuclear and coal generation in California.

Natural gas combined cycle plants and combustion turbines are modeled as dispatchable technologies. 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. All thermal technologies in SWITCH have a fixed heat rate throughout all investment periods (see Supplemental Table 2).

All existing cogeneration plants are given the option to continue operation indefinitely at the existing plant's capacity, efficiency and cost. New cogeneration plants are not allowed to be installed in the current version of the model.

10.3.2. Non-Renewable Thermal Generators Equipped with Carbon Capture and Sequestration (CCS)

Generators equipped with carbon capture and sequestration (CCS) equipment are modeled similarlyto their non-CCS counterparts, but with different capital, fixed O&M and variable O&M costs, as well as different power conversion efficiencies. Newly installable non-renewable CCS technologies are: Gas Combined Cycle, Gas Combustion Turbine, Coal Steam Turbine, Coal Integrated Gasification Combined Cycle. In addition, all carbon-emitting existing 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.

Costs for Gas Combined Cycle, Coal Steam Turbine and Coal Integrated Gasification Combined Cycle generators with CCS are used directly from the United States Energy Information Agency's Updated Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010b). In order to account for the additional cost of installing a CCS system into types of power plants for which consistent and up-to-date CCS cost data is not readily available, the capital cost difference between non-CCS and CCS generators with the same primemover is added to the capital cost of the non-CCS generator. For example, the capital cost of Gas Combustion Turbine CCS is assumed to be equal to the capital cost of non-CCS Gas Combustion Turbine plus the difference in capital costs between Gas Combined Cycle and Gas Combined Cycle CCS (all values in units of $/W). The same method is used for fixed O&M costs. 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. Costs input into the model can be found in the table of generator costs and efficiencies above.

Large-scale deployment of CCS pipelines would require large interconnected pipeline networks from CO_2 sources to CO_2 sinks. While the cost of construction of short pipelines is included in the Updated Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010b), 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 does not contain an adequate CO_2 sink (National Energy Technology Laboratory, 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 those found in Middleton et al., 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 2015-2025 investment period, as gigawatt scale deployment would not be feasible in this timeframe. Starting in 2025, CCS generation can be installed in unlimited quantities (except for bio projects that are limited by the amount of available biofuel).

10.4. 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. During peak hours, CAES adds natural gas to the compressed air and releases the mixture into the intake of a gas turbine. CAES projects in the WECC version of SWITCH are cited in aquifer geology. Geospatial aquifer layers are obtained from the United States Geological Survey (United States Geological Survey 2003) and all sandstone, carbonate, igneous, metamorphic, and unconsolidated sand and gravel aquifers are included (Succar and Williams 2008; Electric Power Research Institute 2003). A density of 83 MW/km^2 is assumed, following (Succar and Williams 2008), resulting in nearly unlimited CAES potential in almost all load areas.

A storage efficiency of 81.7% is used, in concert with a round trip efficiency of 1.4 (Succar and Williams 2008) to apportion generation between renewable and non-renewable fuel categories when RPS is enabled, as natural gas is burned in addition to the input electricity from the grid. In addition, a compressor to expander ratio of 1.2 (Greenblatt *et al.* 2007) is assumed.

10.5. Battery Storage

Sodium sulfur (NaS) batteries are modeled using performance data from (Electric Power Research Institute 2002) for load-leveling batteries. Storage is modeled using a daily energy balance – it is therefore assumed that NaS batteries have sufficient energy capacity to provide daily load-leveling. An AC-DC-AC storage efficiency of 76.7 % is used. NaS battery storage is available for construction in all load areas and investment periods.

10.6. Geothermal

New sites for geothermal steam turbine power projects are compiled from two separate datasets of geothermal projects under consideration from power plant developers (Ventyx EV Energy Map 2009, Western Governors' Association 2009b). 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 costs. These projects represent 7 GW of new geothermal capacity potential.

10.7. Biogas and Biomass Solid

County-level biogas availability (Milbrandt 2005) is divided into load areas by the fraction of land area overlap of each county in each load area. 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 connection cost for connection to the existing electricity. It is assumed that new biogas plants will use combustion turbine technology.

New biomass solid generation is assumed to use integrated gasification combined cycle technology. Installation of biomass solid generation is constrained by the resource availability if biomass solid fuel in each load area.

New biogas and biomass solid combined heat and power units (cogenerators) can be installed to replace existing plants, but cannot be expanded beyond the existing cogeneration potential.

CCS biogas generation is included in all scenarios discussed in this report, while biomass solid integrated gasification combined cycle generation is only available in the Biomass CCS scenario. Sequestration of biomass solid and biogas is modeled as carbon negative with 85% carbon capture efficiency. Biogas CCS is assumed to capture both pre- and post-combustion CO_2 (biogas is typically ~1:1 CH_4:CO_2).

10.8. Wind and Offshore Wind Resources

Hourly wind turbine output was obtained from the 3TIER wind power output dataset produced for the Western Wind and Solar Integration Study (WWSIS) (3TIER 2010). 3TIER modeled 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 was found to contain 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 that were selected by the following criteria to create a final dataset of 32,043 wind points:

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 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 wind points within WECC are aggregated into 3,362 wind farms. Many of the wind points were 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 (3TIER 2010) 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 wind points to create the hourly output of 3,314 onshore (875 GW) and 48 offshore (6 GW) wind farms.

Canadian hourly wind data will be integrated into future versions of the model.

10.9. Solar Resources

10.9.1. Weather file creation

Hourly weather and insolation files in the standard typical meteorological year 2 (TMY2) format for 41,000 sites for the historical years 2004 and 2005 were created by merging 10km-resolution gridded satellite insolation data from the State University of New York (SUNY) (Perez *et al*. 2002; National Renewable Energy Laboratory 2010b) and ~38km-resolution data from the National Center for Environmental Prediction's (NCEP) Climate Forecast System Reanalysis (CFSR) (Saha *et al*. 2010; National Climatic Data Center 2010).

The CFSR data are modified using standard approximations to conform to the TMY2 format. Wind velocity as reported by CFSR is at height of 10 meters – to convert to the TMY2 height of 2 meters, the friction coefficient of 1/7 is used (Masters 2004). Snow water equivalent is converted to snow depth using a 0.1 density conversion factor (Saha *et al*. 2010). Specific humidity is converted to relative humidity (Holton, Pyle, and Curry 2003) and the dew temperature is calculated (National Oceanic and Atmospheric Administration 2009). Wet bulb temperature is estimated from dry bulb temperature using the "1/3 rule" (Haby n.d.).

Time-shifted SUNY gridded insolation data as downloaded from the National Solar Radiation Database (National Renewable Energy Laboratory 2010b) was modified due to an error in time-shifting the direct normal insolation (DNI) values for a fraction of the sunset hours. In these hours, representing 0.1% of the hours, the DNI on a horizontal surface significantly exceeds the largest possible value of clear sky insolation, taking into account the air mass present at each grid cell (Meinel and Meinel 1976) and solar incidence angles (Duffie and Beckman 2006). When the SUNY value for DNI exceeded the largest possible value by more than 100 Wm^{-2}, the largest possible

DNI value was used instead of the SUNY value. SUNY values for the diffuse and global radiation did not to have this problem, and as such were left unmodified.

The CFSR weather grid was combined with the SUNY grid by finding the CFSR grid cell centroid nearest to each SUNY grid cell centroid. For coastal SUNY grid cells, the centroid of the nearest land-based CFSR grid cell was used, as weather conditions change rapidly on the ocean-land boundary and all modeled solar projects are on land.

The weather files are used as inputs to the National Renewable Energy Laboratory's Solar Advisor Model (National Renewable Energy Laboratory 2010a) to calculate the simulated historical output of various types of solar projects.

10.9.2. Distributed Photovoltaics – Residential and Commercial

Residential and Commercial photovoltaic sites were chosen by overlaying a United States raster layer of population density with the SUNY grid cells and selecting any grid cell with a total population greater than 10,000 in the year 2000. Mexican and Canadian cities in WECC with a population greater than 10,000 were included if they were located within the SUNY insolation grid. This includes most major Mexican population centers in Baja California Norte, as well as many of the southern Canadian cities in WECC. This process produced 920 individual SUNY grid cells to simulate residential and commercial photovoltaic systems in WECC. These cells were aggregated to 222 sites by joining adjacent grid cells such that the standard deviation of average global horizontal radiation values within each aggregated site is less than 0.1 kWh/m^2/day. This is accomplished by sequestering grid cells with greater than +/- 0.2 kWh/m^2/day from the average global horizontal radiation value within each aggregated area into a smaller aggregated area.

In SAM, residential, commercial and central station photovoltaic systems are simulated using the California Energy Commission module model as 270 W multi-crystalline silicon Suntech STP270-24-Vb-1 modules.

For residential photovolatics, these modules are connected in a 10-module string to make a 2.7 kW array and are coupled with a 3 kW SMA America SB3000US 208 V inverter. The array is southward facing, not shaded, and is tilted at an angle equal to the latitude of the SUNY grid cell. The module-to-grid derating factor is assumed to be 89%.

Commercial photovoltaic systems are simulated as a 100 kW array with a single point efficiency inverter at 95% efficiency and a DC capacity of 105 kW. The array is southward facing, not shaded, and is tilted at an angle equal to the latitude of the SUNY grid cell. The module-to-grid de-rating factor is assumed to be 91%.

The roof area available for distributed photovoltaic development is estimated based on Navigant (Chaudhari, Frantzis, and Hoff 2004) and NREL (Denholm and Margolis 2007) reports. State-level roof area data (Chaudhari, Frantzis, and Hoff 2004) projected to 2025 is apportioned to load areas by population fraction. Twenty percent of all residential and 60% of all commercial roof area is assumed to be available for development. The rooftop spacing ratio for commercial photovoltaics is derived from the Department of Defense Unified Facilities Criteria (United States Department of Defense 2002). Canadian rooftop availability is assumed to be similar to that of the nearest U.S. state. Baja California Norte rooftop availability is scaled by GDP from California values. In total, 117 GW of residential and 88 GW of commercial photovoltaics are included.

10.9.3. Central Station Solar – Photovoltaics and CSP

Land suitable for large-scale solar development is derived using land exclusion criteria from Mehos and Perez (2005), but without a minimum insolation cutoff. Types of land excluded are: national parks, 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 available solar land is aggregated on the basis of average global insolation and DNI. An iterative procedure that partitions available solar land polygons with standard deviations of greater than 0.05 kWh/m^2/day average global insolation or DNI into smaller polygons is employed to create the final solar farms.

In SAM, central station photovoltaics are modeled as 100 MW (AC) arrays using the same mulitcrystalline panels discussed above and mounted on a single axis tracker. The array is connected to a single point efficiency inverter with 95% efficiency. The tracker is modeled using SunPower specifications (SunPower Corporation 2009), and as such is southward facing at a 20° tilt on a one-axis tracker, with ground coverage ratios of 0.20 at low latitudes, increasing to 0.24 at high latitudes. A de-rating factor of 90% is used to convert from power produced at the module to power available to the grid. A total of 15 TW of central station photovoltaic systems are simulated; after site selection (see Section III.10.8.4) this is reduced to 4 TW.

CSP systems without thermal storage are modeled in SAM using the 'Physical Trough' model for CSP parabolic trough systems. In total, 100 MW nameplate systems using Solargenix SGX-1 collectors in an 'H' configuration with an evaporative cooling system are modeled with a total field aperture area calculated by minimizing the total levelized cost of energy with respect to aperture area. Costs for CSP systems are scaled to this aperture area from the base cost values. A total of 15 TW of CSP trough systems without storage are simulated; after site selection, this is reduced to 5 TW.

In the future, CSP trough systems with thermal storage will be simulated as above, but a bug in the storage dispatch of the latest available version of SAM makes this method impossible at present. Rather, the hourly output of 125 CSP trough sites (representing 272 GW of capacity) with six hours of thermal storage was obtained from the National Renewable Energy Laboratory. Dispatch of CSP storage is embedded in the hourly capacity factors – it is an input parameter rather than a variable.

10.10. Site Selection of Intermittent Projects

To decrease runtime, the number of solar and wind sites is reduced using criteria that retain the best quality resources, geographic diversity, and load-serving capability of each resource.

1) All sites with capacity factors that are at least 75% of the average capacity factor for their technology are included.
2) If more than five sites for the same technology are present in a load area, at least 10 of the highest average capacity factor projects are also retained.

3) Projects were selected such that the average generation (the capacity factor multiplied by the resource potential) of a technology, where sufficient resources exist, must be greater than or equal to three times the average 2010 load in each load area.

These criteria primarily filter out onshore wind, as well as central station photovoltaic and solar thermal sites, for which there is enormous potential in WECC. All distributed photovoltaic and offshore wind sites are retained.

References

3TIER, 2010. Development of regional wind resource and wind plant output datasets. National Renewable Energy Laboratory, Subcontract Report NREL/SR-550-47676, March 2010.

American Wind Energy Association, 2010. U.S. wind energy projects. Washington, DC, 2010; http://www.awea.org/projects/).

Black & Veatch, 2010. Input assumptions spreadsheet. Renewable Energy Deployment System (ReEDS), National Renewable Energy Laboratory, Boulder, CO, 2010.

California Energy Commission, 2010. Cost of generation model, version 2; http://www.energy.ca.gov/2010publications/CEC-200-2010-002/index.html.

Chaudhari, M., L. Frantzis, T. E. Hoff, 2004. PV grid connected market potential under a cost breakthrough scenario. Navigant Consulting, Burlington, Massachusetts, 2004; http://www.ef.org/documents/EF-Final-Final2.pdf.

Denholm, P. and R. Margolis, 2007. Supply curves for rooftop solar PV-generated electricity for the United States. National Renewable Energy Laboratory, Boulder, CO, Technical Report NREL/TP-6A0-44073, 2007; http://www.nrel.gov/docs/fy09osti/44073.pdf.

de la Torre Ugarte, D. and D.E. Ray, 2000. Applications of the POLYSIS Modeling Framework. *Biomass and Bioenergy* **18**(4) p. 291-308.

Duffie, J. A. and W. A. Beckman, 2006. *Solar Engineering of Thermal Processes* (Wiley, New Jersey, ed. 3, 2006).

Electric Power Research Institute, 2002. Handbook of Energy Storage for Transmission or Distribution Applications. Technical Update, Palo Alto, CA, December 2002.

Electric Power Research Institute, 2003. Handbook of energy storage for transmission and distribution applications. Palo Alto, CA, 2003.

Electricity Storage Association, 2010. Technologies: pumped hydro. Washington, DC, 2010; http://www.electricitystorage.org/site/technologies/pumped_hydro/.

Federal Energy Regulatory Commission, 2006. Form 714: Annual Electric Balancing Authority Area and Planning Area Report. Washington, DC, 2006.

Federal Energy Regulatory Commission, 2009. Form 715: annual transmission planning and evaluation report, 2009. Washington, DC, 2009.

Fripp, M., 2008. *Optimal Investment in Wind and Solar Power in California*, doctoral dissertation, University of California, Berkeley, 2008; http://disexpress.umi.com/dxweb#download?&type=pdf&dpubno=3388273.

Fripp, M., 2012. Switch: a planning tool for power systems with large shares of intermittent renewable energy. Accepted in *Environmental Science and Technology*, 2012.

GE Energy, 2010. Western wind and solar integration study. National Renewable Energy Laboratory, Boulder, CO, Subcontract No. AAM-8-77557-01, 2010; http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf).

Haby, J., n.d. Shortcut to calculating wet-bulb. Mississippi State University; http://www.theweatherprediction.com/habyhints/170/.

Greenblatt, J. B. *et al*., 2007. Baseload wind energy: modeling the competition between gas turbines and compressed air energy storage for supplemental generation. *Energy Policy* **35**, 1474-1492 (March 2007).

Holton, J.R., J. Pyle, J. A. Curry, Eds, 2003. *Encyclopedia of Atmospheric Sciences* (Academic Press, ed. 1, 2003).

Klein, J., 2010. Comparative costs of California central station electricity generation technologies: cost of generation model. California Energy Commission, Sacramento, CA, 2007; http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF.

Kumarappan, S. et al., 2009. Biomass supply for biofuel production: estimates for the United States and Canada. *BioResources* 4(3), 1070-1087.

London Economics and Global Energy Decisions, 2007. Performance of six European wholesale electricity markets in 2003, 2004, and 2005, Appendix I; http://ec.europa.eu/competition/sectors/energy/inquiry/electricity_final_appendix1.pdf.

Masters, G.M., 2004. *Renewable and Efficient Electric Power Systems* (Wiley-Interscience, New Jersey, 2004), p. 319.

Mehos, M. and R. Perez, 2005. Mining for solar resources: U.S. Southwest provides vast potential. *Imaging Notes* **20** (Summer 2005).

Meinel, A.B. and M.P. Meinel, 1976. *Applied Solar Energy* (Addison Wesley Publishing Co., Massachusetts, 1976).

Milbrandt, A., 2005. A geographic perspective on the current biomass resource availability in the United States. National Renewable Energy Laboratory, Boulder, CO, 2005.

National Climatic Data Center, 2010. Climate forecast system reanalysis (CSFR). Asheville, North Carolina, 2010; http://nomads.ncdc.noaa.gov/data/cfsr/.

National Energy Technology Laboratory, 2008. National Carbon Sequestration Database and Geographic Information System. United Stated Department of Energy, 2008; http://www.netl.doe.gov/technologies/carbon_seq/natcarb/index.html.
National Oceanic and Atmospheric Administration, 2009. Relative humidity and dewpoint temperature from temperature and wet-bulb temperature. Washington, DC, 2009; http://www.srh.noaa.gov/images/epz/wxcalc/rhTdFromWetBulb.pdf.

National Renewable Energy Laboratory, 2010a. Solar Advisor Model. Boulder, Colorado, 2010; https://www.nrel.gov/analysis/sam/).

National Renewable Energy Laboratory, 2010b. Renewable resource data center. Boulder, CO, 2010; http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/.

North Carolina State University, 2011. Database of state incentives for renewables and efficiency. Raleigh, NC, 2011; http://www.dsireusa.org/.

Parker, N. C., 2011. *Modeling Future Biofuel Supply Chains using Spatially Explicit Infrastructure Optimization*, doctoral dissertation, University of California, Davis, 2011.

Perez, R. *et al*., 2002. A new operational satellite-to-irradiance model. *Solar Energy* **73**, 307–317 (November 2002).

Platts Corporation, 2009. POWERmap: Substation Layer. Westminster, CO, 2009; http://www.platts.com/Products/powermap).

Saha, S. *et al*., 2010. The NCEP climate forecast system reanalysis. *Bulletin of the American Meteorological Society* (Early Online Release, 2010; http://journals.ametsoc.org/doi/pdf/10.1175/2010BAMS3001.1.

Secretaría de Energía, 2010. Programa de obras e inversions del sector eléctrico 2010-2024. Mexico, 2010; http://www.energia.gob.mx/portal/Default.aspx?id=1453.

Succar, S. and R. H. Williams, 2008. Compressed air energy storage: theory, resources, and applications for wind power. Princeton Environmental Institute, Princeton, New Jersey, 2008; http://www.princeton.edu/pei/energy/publications/texts/SuccarWilliams_PEI_CAES_2008April8.pdf).

SunPower Corporation, 2009. SunPower T20 Tracker. San Jose, California, Document #001-56702 Rev**/LTR_EN, 2009; http://us.sunpowercorp.com/downloads/product_pdfs/trackers/SunPower_t20tracker_en_lt_w_ra.pdf.

The Wind Power, 2010. Wind turbines and wind farms database. Buc, France, 2010; http://www.thewindpower.net/index_turbines.php).

University of Tennessee, Agricultural Policy Analysis Center: POLYSYS - Policy analysis System, 2007; http://www.agpolicy.org/polysys.html.

United States Department of Defense, 2002. Unified Facilities Criteria (UFC): active solar preheat systems. Washington, DC, UFC 3-440-01, 2002; http://www.wbdg.org/ccb/DOD/UFC/ufc_3_440_01.pdf).

United States Department of Energy, 2010. Solar Vision Study. Washington, DC, 2010; http://www1.eere.energy.gov/solar/vision_study.html).

United States Department of Labor, 2009. Occupational pay comparisons among metropolitan areas. Bureau of Labor Statistics, Washington, DC, 2009.

United States Energy Information Agency, 2007a. Form EIA-860 database annual electric generator report. Washington, DC, 2007.

United States Energy Information Agency, 2007b. Form EIA-906. Washington, DC, 2007.

United States Energy Information Agency, 2010a. Annual energy outlook 2010. Washington, DC, 2010.

United States Energy Information Agency, 2010b. Updated Capital Cost Estimates for Electricity Generation Plants. Washington, DC, 2010.

United States Energy Information Agency, 2011. Annual energy outlook 2011. Washington, DC, 2011.

United States Federal Energy Regulatory Commission, 2005. Form 714 – annual electric balancing authority area and planning area report, 2004-2005. Washington, DC, 2005.

United States Geological Survey, 2003. Principal aquifers of the 48 conterminous United States, Hawaii, Puerto Rico, and the U.S. Virgin Islands. Reston, Virginia, 2003; http://nationalatlas.gov/atlasftp.html.

Ventyx EV Energy Map, 2009. Ventyx Corporation, Atlanta, GA; http://www.ventyx.com/velocity/ev-energy-map.asp).

Walsh, M.E. *et al*., 2000. Biomass feedstock availability in the United States: 1999 state level analysis. Oak Ridge National Laboratory, Oak Ridge, Tennessee, 2000.

Westergaard, C., 2009. Basic and idealized rotor power curve: Version 0.56a. Vestas Corporation, Randers, Denmark, 2009.

Western Electricity Coordinating Council, 2009. 2009 Western Interconnection transmission path utilization study. Salt Lake City, UT, 2009; http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/TEPPC%20Annual%20Reports/2009/2009%20Western%20Interconnection%20Trasnsmission%20Path%20Utilization%20Study.pdf).

Western Electricity Coordinating Council, 2009. Powerbase database of generators. Salt Lake City, UT.

Western Governors' Association, 2009a. Western renewable energy zones GIS portal. Washington, DC, United States Department of Energy, Washington, DC, 2009; http://mercator.nrel.gov/wrez/).

Western Governors' Association, 2009b. Western renewable energy zones - Phase 1 report. Washington, DC, United States Department of Energy, Washington, DC, 2009; http:// www.westgov.org/wga/publicat/WREZ09.pdf.

White House Office of Management and Budget, 2010. Circular No. A94 Revised. Washington, DC, 2010; http://www.whitehouse.gov/omb/circulars_a094#8).

Youngs, Heather, 2010. California Biofuels Stress Test, unpublished.