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SI.1. INTRODUCTION

SI.1.1. Model Overview

Switch is a stochastic, linear optimization model, designed to choose optimal investments in renewable and conventional power plants in a large region over a multi-decade period, in order to reduce greenhouse gas emissions at the lowest cost, while maintaining a reliable supply of power.

Switch divides the study region into a number of separate load zones joined together by transmission corridors. The study period is divided into several multi-year investment periods.

Four sets of decisions constitute a long-term power-system investment plan, which is the most important output from the Switch model. These decisions are made at the start of each investment period:

1. How much generation capacity to add of each technological type (wind, solar, natural gas) in each load zone.
2. How much transmission capacity to add between each pair of load zones.
3. How much local transmission and distribution capacity to add within each load zone.
4. Whether to mothball existing power plants.

Switch makes additional decisions about how to operate this infrastructure every hour during the study period. These decisions are co-optimized with the investment plan, and include:

1. How much power to generate from dispatchable generators (natural gas or hydroelectric), in each load zone.
2. How much power to store at each pumped-hydroelectric storage facility.
3. How much power to transfer along each transmission corridor.

SI.1.2. Weather-Related Uncertainty

Wind and solar power and electricity loads all vary with the weather. This makes it unclear in advance what combination of resources will be needed in order to serve electricity loads reliably, at the lowest cost, while reducing greenhouse gas emissions. Switch addresses this uncertainty directly, via stochastic programming: simultaneously optimizing the investment decisions with operational decisions under a wide variety of weather conditions. This sampling process is discussed further in Section SI.2.2 on Switch's calendar.

SI.1.3. Non-Weather Uncertainty

Power plants and transmission lines can stop working correctly at any time, due to mechanical failure, damage or other factors. In generation adequacy studies, it is common to address this risk by running a Monte Carlo simulation of the power system over many possible future hours. During each hour, each piece of equipment is randomly placed in or out of service, with a probability based on its average forced outage rate. If there are many hours when loads cannot be served due to equipment failures, then more generation or transmission capacity is added to the simulated power system, and the process is repeated until the system is reliable enough. These simulations can also reveal the expected cost of operating the system under the range of possible future conditions.

This approach is too computationally intensive to implement within an investment optimization model, so Switch addresses non-weather risk on a statistical basis instead. This includes two elements:

First, rather than consider all possible permutations of forced outages, Switch builds enough generation and transmission capacity to meet loads 15% higher than expected at all locations in all hours. This is similar to the approach taken in California's energy planning process (1, 2) and the planning requirements placed on California retail electricity suppliers. This planning reserve margin is substantially more than the forced outage rate of power plants, and generally appears to provide adequate reliability (3).

Second, Switch performs all economic analysis on an expected-value basis. It would be unrealistic to expect to obtain 100 percent of the rated power from a plant at all times. Instead, for its economic analysis, Switch de-rates the nameplate capacity of every power plant and transmission line based on its forced outage rate. For example, if a natural gas power plant has a nameplate capacity of 100 MW and a forced outage rate of 5 percent, then the Switch model only assumes that it can obtain 95 MW from that plant on average in all future hours. This ensures that the costs calculated for operation of the power system are based on the resources that are expected to be available in each hour, not the maximum that could be available if every piece of equipment worked correctly.[1] This de-rated capacity is similar to the "unforced capacity" used for generating plants in the NYISO and PJM capacity auctions (4).

Switch implements this approach to non-weather-related risk by making operating decisions for two different scenarios simultaneously. The first set of decisions shows how the system would be operated under a "reserve-margin" scenario: if all equipment worked correctly, but each load zone needed 15 percent extra electricity in each hour. The second set of decisions describes how the system would be operated under an "expected-conditions" scenario: satisfying expected loads in every hour, but only using as much capacity from each generator or transmission line as is expected to be available on average. Switch uses a single set of investment decisions for both scenarios, and only the expected-conditions operating decisions are included in the model's cost analysis. Consequently, Switch makes investment decisions that satisfy the planning reserve margin requirement, but should also yield the lowest possible costs under expected conditions.

SI.1.4. Cost Assessment (Objective Function)

The total cost of delivering power includes five components: (1) the capital cost of building power plants, (2) operations and maintenance (O&M) costs incurred each year at active power plants, (3) variable O&M costs incurred for each megawatt-hour of electricity produced by each plant, (4) the cost of any fuel used to generate electricity, and (5) a "carbon cost" that reflects the direct or indirect cost of each metric ton of carbon dioxide emitted by a power plant.[2] For transmission capacity, only a capital cost and annual fixed O&M cost are considered. The cost of building and maintaining local transmission and distribution infrastructure is represented by a simple annual payment that must be made to finance and maintain each MW of capacity in each zone.

Capital costs are amortized as an annual payment each year during the expected life of each plant or transmission line, and only those payments that occur during the study are considered. For computational convenience, these annual payments are further divided into hourly costs during the life of each project. All future costs are discounted to a present-day value using a common discount rate. All costs are specified in real terms, indexed to a specific reference year.

Switch's objective is to minimize these discounted costs. This can be summarized as

[1] This discussion neglects the scheduled outage rate, for required maintenance that can be scheduled as needed throughout the year. For non-baseload plants, it is assumed that maintenance can be scheduled for times when the plant is not needed, so it will not affect the economic calculations. For baseload plants, the expected output in each hour is de-rated by both the forced outage rate and the scheduled outage rate.

[2] The "carbon cost" may be a proposed tax, or may be a marginal benefit or cost of emission reduction that is used only for analytical purposes. This issue is discussed further under "Carbon Dioxide Emission Taxes," below.

minimize:

$$\sum_{h \in \mathrm{HOURS}} \mathrm{hourly\_cost\_weight}_h \cdot \begin{pmatrix} \mathrm{NewGenCapitalCostPerHour}_h + \mathrm{NewGenFixedCostPerHour}_h \\ + \mathrm{NewGenVariableCostPerHour}_h + \mathrm{NewGenCarbonCostPerHour}_h \\ + \mathrm{ExistingGenCapitalCostPerHour}_h + \mathrm{ExistingGenFixedCostPerHour}_h \\ + \mathrm{ExistingGenVariableCostPerHour}_h + \mathrm{ExistingGenCarbonCostPerHour}_h \\ + \mathrm{HydroCostPerHour}_h \\ + \mathrm{NewTransCapitalCostPerHour}_h + \mathrm{ExistingTransCapitalCostPerHour}_h \\ + \mathrm{LocalTDCostPerHour}_h \end{pmatrix}$$

Here, HOURS is a list of all the sampled hours included in the optimization and $\mathrm{hourly\_cost\_weight}_h$ includes weighting and discount factors to convert costs during hour h into present values (these are discussed further in Section SI.2). The other terms are subcomponents defined in terms of Switch's decision variables and input parameters; these are discussed in detail in Sections SI.3–SI.9.

SI.1.5. Load-Serving Constraints

The chief constraint in Switch is that existing and new power plants and transmission lines must be able to satisfy electricity loads in each zone during every hour of the study. As discussed in Section SI.1.3, it must be possible to meet this constraint under two different scenarios – with expected loads or loads augmented by a reserve margin.

Under expected conditions, the load-serving constraint (in summary form) is given by

subject to (for each hour h and load zone z):

$$\begin{aligned} &\mathrm{NewGenOutput}_{z,h} + \mathrm{ExistingGenOutput}_{z,h} \\ &\quad + \mathrm{HydroOutputEnergy}_{z,h} - \mathrm{HydroStorageEnergy}_{z,h} \\ &\quad + \mathrm{NetImports}_{z,h} \\ &\geq \mathrm{system\_load\_fixed}_{z,h} + \mathrm{DispatchSystemLoad}_{z,h} \end{aligned}$$

Note that the total supply of power can exceed the demand for power, indicating that some renewable or hydroelectric power is discarded unused during that hour.

In the reserve-margin scenario, the load-serving constraint is summarized as

subject to (for each hour h and load zone z):

$$\begin{aligned} &\mathrm{NewGenMaxOutput}_{z,h} + \mathrm{ExistingGenMaxOutput}_{z,h} \\ &\quad + \mathrm{HydroOutputEnergy\_Reserve}_{z,h} - \mathrm{HydroStorageEnergy\_Reserve}_{z,h} \\ &\quad + \mathrm{NetImports\_Reserve}_{z,h} \\ &\geq \mathrm{system\_load\_fixed}_{z,h} \end{aligned}$$

The subcomponents of these constraints are defined in terms of Switch's decision variables and input parameters. They are discussed in detail in Sections SI.3–SI.9

SI.1.6. Notation for Switch Model Elements

Sets define most of the options available to Switch – locations for power plants and transmission lines, hours of operation, technologies available for installation, etc. Restricted sets are also used instead of constraints in many cases, e.g., Switch only considers running power plants during the hours before they retire (listed in a set), rather than constraining each plant's output to equal zero after retirement. In the equations above and in later sections, the names of sets are written in all capital letters (e.g., HOURS).

Individual members of sets are often addressed with indexing variables. These are always written with single lower-case letters (e.g., h) or tuples of single lower-case letters (e.g., (z, t, s, o)). There is a one-to-one correspondence between indexing variables and sets (e.g., h always refers to a member of HOURS and members of HOURS are always indexed by h).

Decision variables indicate choices made by Switch. These are written with mixed capital and lower case (e.g., InstallGen).

Finally, parameters provide data describing the objects listed in sets, e.g., the power production during each hour from each renewable energy project, or the carbon content of each fossil fuel. Parameters use multi-letter names written in all lower-case letters.

Subcomponents of Switch's objective function and load-serving constraints (shown above and described in more detail below) are simple functions of decision variables and parameters. Like decision variables, they use mixed capital and lower-case letters, but it should generally be possible to distinguish them from based on context.

SI.1.7. Continuous Decision Variables

Many of the decisions made by Switch should in principle be constrained to integer values (e.g., adding transmission or generation capacity in fixed increments). However, to simplify the model definition and accelerate calculation, all decision variables are allowed to take continuous values. This assumption is reasonably accurate in large power systems, where the size of a single plant or transmission line is small compared to the total size of the system (so that using non-integer values introduces only a small percentage error). Furthermore, in many cases Switch sets these variables to their lower or upper limit (e.g., developing all the available wind capacity in the most attractive regions), which would also be valid values in an integer formulation. However, some attention should be given to the proposed investment portfolios, to make sure they use plausible amounts of capacity.

SI.2. CALENDAR AND GEOGRAPHY

SI.2.1. Introduction

Tables SI.1 and .2 summarize the sets and parameters used by Switch to define the temporal and geographic scope of the power system. They are presented here for reference while reading the following subsections, which describe Switch's calendar and geography in more detail.

Table SI.1. Sets used to define the calendar and geography in Switch

Name	Indexing variable(s)	Description	Definition
DATES	*d*	Unique ID for each sample date included in the study	Specified along with HOURS. {for h $\in$ HOURS: $date_h$}
HOURS	*h*	Sample hours included in the study	Specified exogenously. For the California study this includes all even-numbered hours for one typical day and one peak day, during even-numbered months, for each investment period (4 periods × 6 months × 2 days / month × 12 hours / day = 576 sample hours). Each sample hour corresponds to historical load and weather conditions during one real hour in 2004.
HOURS_OF_DAY	(n.a.)	Hours of the day that are included in the model (may not include all 24 hours).	Specified along with HOURS. {for h $\in$ HOURS: $hour\_of\_day_h$}
LOAD_ZONES	*z*	Zones within which power can move freely, but between which transmission may be congested	Specified exogenously. For the California study this includes16 historical congestion zones within California and two external zones for imported power.
PERIODS	*p*	First year of each investment period included in the study	Specified exogenously. For the California study this includes four 4-year periods starting in 2012, 2016, 2020 and 2024 .
SEASONS_OF_YEAR	(n.a.)	Seasons of the year that are included in the model.	Specified along with HOURS. {for h $\in$ HOURS: $season\_of\_year_h$}
VINTAGE_YEARS	*v*	Years when new power plants or transmission lines can be built	identical to PERIODS.

Table SI.2. Parameters used to define calendar and geography in Switch

Name	Indexed over	Description	Definition
annual_cost_ weight	PERIODS	Discounting factor used to convert annual costs that occur in period p into present values in the base year. Annual costs are assumed to recur during every year of period p. They are first discounted to the start of the period, then to the base year.	$\text{annual\_cost\_weight}_p = \dfrac{1-(1+\text{discount\_rate})^{-\text{years\_per\_period}}}{\text{discount\_rate}} \cdot (1+\text{discount\_rate})^{-(p-\text{base\_year})}$
date	HOURS	Sample date (from DATES) that contains hour *h*.	Specified exogenously.
discount_rate	(single value)	Discount rate used to convert future costs into present values in the base year.	Specified exogenously.
end_year	(single value)	First year beyond the end of the study.	Last year in PERIODS plus years_per_period.
ep_finance_rate	(single value)	Finance rate used to amortize the capital costs of existing power plants.	Specified exogenously.
finance_rate	TECHNOLOGIES	Finance rate used to amortize capital costs over the life of generation projects.	Specified exogenously.
hour_of_day	HOURS	Hour of day (from HOURS_OF_DAY) represented by sample hour *h* (e.g., the hour starting at 4 p.m.)	Specified exogenously.
hourly_cost_ weight	HOURS	Combines a weighting factor and a discount factor to convert hourly costs into present values in the base year. Hourly costs are first weighted to calculate total costs during each investment period, then divided by years_per_ period to calculate annual costs, then discounted to the base year using annual_cost_weight.	$\text{hourly\_cost\_weight}_h = \text{hours\_in\_sample}_h / \text{years\_per\_period} \cdot \text{annual\_cost\_weight}_{\text{period}_h}$
hours_in_sample	HOURS	Weight given to each sample hour used in the optimization. This accounts for the number of days of each month represented by hour *h* (e.g., 1 for peak days, 27 to 30 for typical days), as well as the amount of subsampling within each investment period (e.g., 2 x 4 if one sampled date is used to represent 2 months of the year for 4 years). $\Sigma_{h \in HOURS}$ *hours_in_sample* should equal the total number of calendar hours represented by the simulation.	Specified exogenously.
period	HOURS	Investment period (from PERIODS) that contains hour *h*.	Specified exogenously.
season_of_year	HOURS	Season of the year (from SEASONS_ OF_YEAR) in which sample hour *h* falls (e.g., 1 for winter).	Specified exogenously.
start_year	(single value)	First year of the study.	First year in PERIODS.
transmission_ finance_rate	(single value)	Finance rate used to amortize capital costs over the life of transmission projects.	Specified exogenously.
years_per_ period	(single value)	Number of years included in each study period in PERIODS.	(last year in PERIODS – first year in PERIODS) / (n_{PERIODS} – 1)

SI.2.2. Calendar

Switch makes investment and operation choices for several future, multi-year investment periods. Each investment period includes a number of sample dates, each of which contains several hour-long dispatch periods. The model makes investment decisions at the start of each investment period, and then chooses how to dispatch generators and transmission lines to satisfy electricity loads during each sampled hour. In the sections below, the term "investment period" refers to the multi-year investment period, while the terms "operational," "dispatch" or "hourly" refer to decisions and constraints that apply to the individual dispatch periods within each investment period.

Electricity loads vary over time, as do the availability of hydroelectric, wind and solar power, all due in large part to variations in the weather. To account for any correlation between loads and the availability of renewable resources, each date modeled in Switch is matched to a specific historical date. Then, loads, wind, solar and hydroelectric availability during the simulated date are derived from the conditions that occurred during the matching historical date.[3]

Conditions other than the weather are assumed to be identical for all hours within each investment period. These include such factors as average load growth, equipment cost projections, fuel price forecasts or plant retirements: any generator that is operational at the beginning of each period is assumed to be usable for all hours in the period, and forecasts of loads and prices for the first year of the period are assumed to apply to all hours during the period.

Switch treats each date separately for hydro dispatch or rescheduling electricity loads, rather than allowing energy production or consumption to be rescheduled over multi-day periods. This is because the model samples each date independently, rather than simulating chronological sequences of days. This approach was adopted in order to sample as wide a variety of weather conditions as possible, while keeping the model computationally feasible.

California Study. For the work reported here, Switch uses four four-year investment periods, beginning in 2012, 2016, 2020 and 2024. Due to computational constraints, Switch can only model a limited number of hours during each investment period. For this work, twelve historical dates are chosen to represent environmental conditions during each investment period. These are made up of two dates for each even-numbered month of the year: one date chosen to reflect typical operating conditions, and one representing a peak-load day for that month. All of these historical dates are chosen from data for 2004.[4] For example, the 2016 study period includes conditions from one randomly chosen October day (10/02/2004), and from the October date with the highest peak load (10/07/2004) in 2004. Conditions on the peak day are re-used for all four investment periods. This sampling method ensures that investment choices provide adequate reserves for the peak load day each period.

For this work, I also used a subsample of the available hours on each date, modeling only the odd-numbered hours.

Because fewer hours are sampled than the actual length of each investment period, each sampled hour is weighted to represent multiple calendar hours during the period, using the $hours\_in\_sample_h$ parameter. For example, for the California study, I begin by giving each hour on the "typical" October date a weight of 30, since it represents conditions that prevail on 30 days of the month. I give hours on the peak date an initial weight of 1, since they represent conditions that prevail on 1 day of the month. Then, I multiply these weights by factors reflecting the model's temporal subsampling: 2 (modeling only odd-

[3] This arrangement allows for some diversity in the dates selected, but also retains a chronological relationship between individual hours of the day. A chronological relationship is necessary in order to model daily hydroelectric energy constraints (e.g., pumped storage); it also allows for the possibility of ramp rate constraints for thermal generators (not included in the current version of the model).

[4] The year 2004 was chosen because this was the only period for which both renewable resource and disaggregated load data are available; it would generally be preferable to choose dates from a longer historical period.

numbered hours) × 2 (modeling only even-numbered months) × 4 (modeling only one year of data for each four-year period). This gives a final weight of 480 for typical hours and 16 for peak-day hours. This weighting system ensures that high-stress conditions are included in the reliability constraints, but typical predominate in the economic assessment of operational decisions.

Because Switch considers a limited sample of dates, there is some risk that it will make different investment choices depending on which historical dates are chosen for study. This problem is most pronounced when a set of dates are chosen that have wind or solar output significantly different from the long-term average. In practice, this is mostly corrected in the post-optimization assessment stage – when looking at weather from all available dates, the system may have higher or lower costs than were expected from the optimization phase, but the cost-vs-emissions relationship found in the all-hours assessment stage tends to stay the same regardless of the dates used in the first stage. However, in order to achieve greater consistency between the two stages, I ran the optimization stage using a set of sample dates with annual average solar and wind output that approximately match the actual annual average.

SI.2.3. Cost Discounting

Capital costs in Switch are generally amortized as annual payments using a technology-specific finance rate (finance_rate, ep_finance_rate or transmission_finance_rate). Capital payments are then converted into hourly repayment requirements and combined with other hourly costs. This approach matches capital repayment with the times when power is produced, so that only the cost of power produced during the study period is included in the study.

Next, hourly costs are weighted and converted into present values using the $\text{hourly\_cost\_weight}_h$ factor. This factor first weights hourly costs to convert them into annual costs, then discounts the annual costs from each year of each investment period into a lump-sum value at the start of the investment period, then discounts this lump-sum back to the reference year.

So, for example, a cost of $100 incurred during an hour in the 2016-19 investment period sampled corresponding to a “typical” October day would first be weighted by 480/4 (hours_in_sample/ years_per_period; see Section SI.2.2), to show that it represents a cost expected to occur 120 times per year. Then this $12,000/year cost would be treated as a recurring annual cost over the 4 years from 2016 through 2019, with a present value in 2016 of $44,605 (with a 3% discount rate). Finally, this cost would be discounted to a present value of $39,631 in 2012. The latter two factors are included in the $\text{annual\_cost\_weight}_p$ parameter.

Discount and finance rates for California study. For the work reported here, I use a real finance rate of 3% (corresponding to home equity finance) for distributed PV systems and a real finance rate of 6% (corresponding to the cost of capital for a regulated utility) for all other projects (finance_rate, ep_finance_rate and transmission_finance_rate). The calculation of present value in 2012 uses a real discount rate (discount_rate) of 3% (corresponding to a public-policy perspective). These rates would be equivalent to nominal rates (including inflation) that are 2–3% higher.

SI.2.4. Geography

Switch divides the study region into several load zones. Transmission corridors can join the centers of any two zones. All central-station generators (e.g., combined-cycle natural gas plants, solar-thermal electric plants, or wind farms) are treated as if their power was delivered to the center of their load zone, directly to the large-scale transmission network. Within each load zone, the local transmission and distribution network is represented by a single value for “local transmission and distribution capacity,” which indicates the maximum zone-wide load that can be served by central-station generation technologies or power imports. During each investment period, Switch chooses whether to build or expand transmission capacity between zones or within each zone.

California Study. For the work reported here, the state of California is divided into 16 load zones, shown in Figure SI.1. Several factors make this a natural scale to divide the state: (1) These regions correspond closely to the "load pockets" traditionally used for reliability analysis in California – they are well-connected internally, but sometimes suffer from congested transmission to neighboring zones; (2) historical hourly electricity loads have been recorded and made publicly available for these regions (and not on any finer scale); (3) this scale is fine enough to reflect much of the geographic diversity of the state; and (4) there are few enough regions that they can be represented in an optimization model which is solvable in a reasonable period of time.

Thirteen of these zones are subdivisions of the region managed by the California Independent System Operator (CAISO), and the remaining three are the service areas of the public utilities serving Sacramento, Los Angeles and the Imperial Irrigation District. Electric utilities based in other states serve some less-populated parts of northern California, and these are omitted from this study. There are also two "virtual" zones corresponding to power supplies available for import from northwestern and southwestern states into the other 16 study zones.

Figure SI.1. California electricity load zones

SI.3. ELECTRICITY LOADS

SI.3.1. Representation of Loads in Switch

Switch includes two types of electricity loads: fixed loads of a pre-specified magnitude each hour, and reschedulable loads which must be satisfied sometime during the day, during hours chosen by the model. One decision variable, $\text{DispatchSystemLoad}_{z,h}$, is used to specify the amount of reschedulable load to serve during each hour in each load zone (see Table .3). The parameters describing these loads are shown in Table .4.

Table SI.3. Load-related decision variable in Switch

Name	Indexing set	Description
DispatchSystemLoad	LOAD_ZONES × HOURS	Number of MW of power to provide to reschedulable loads in each zone during each hour

Table SI.4. Input parameters for electricity loads in Switch

Name	Indexed over	Description	Definition
system_load_ fixed	LOAD_ ZONES × HOURS	Fixed electricity loads in each zone in each hour.	Specified exogenously.
system_load_ moveable	LOAD_ ZONES × DATES	Reschedulable electricity loads in each zone each day. Specified as an average daily load in MW, which can be allocated as needed among all the hours of the day.	Specified exogenously.

Other components of Switch can be used to model the change in fixed loads in response to the annual average price of power, as well as interruptible loads that receive a regular capacity payment in exchange for being disconnectable during critical supply periods.{Fripp, 2008 #269} However, those have been omitted from this work for simplicity.

Switch also includes one constraint to ensure that all reschedulable loads are satisfied over the course of each day:

$$\text{subject to } \left(\text{for z in LOAD\_ZONES, d in DATES}\right):$$
$$\sum_{\text{h in HOURS: date}_h = \text{d}} \text{hours\_in\_sample}_h \cdot \text{DispatchSystemLoad}_{z,h} = \sum_{\text{h in HOURS: date}_h = \text{d}} \text{hours\_in\_sample}_h \cdot \text{system\_load\_moveable}_{z,d}$$

SI.3.2. California Load Data

The hourly profile of electricity loads in each load zone for each sampled day are estimated based on historical hourly measurements reported in two publicly available databases. The California Independent System Operator reports hourly electricity loads for 12 “load aggregation areas” for November 2002 through April 2005, as part of a series of studies on location-specific pricing of electricity made before upgrading their market software (11). Eleven of these load aggregation areas map directly onto load zones in the Switch model. However, in order to create a more geographically realistic simulation, I divide the CAISO’s “Other PG&E” area into two separate regions – “PG&E North” and “PG&E South.” I assign 47.6% of the “Other PG&E” load to the “PG&E North” area and 52.4% to the “PG&E South” area, based on load distribution factors reported for individual buses in each zone (11). The three remaining load zones correspond to California’s three public electric utilities; their loads were obtained from filings of FERC Form 714 for 2004 (12).

Each future day in Switch corresponds to one real, historical day. In order to obtain loads for this future day, loads from 2004 are scaled up to match forecasts of the peak and average annual load for future years. These forecasts are derived from the California Energy Commission’s zonal demand forecast for 2008–18 (13), which escalate linearly over time.[5] I then extend this linear trend for years beyond 2018.

[5] The Energy Commission’s load zones do not match exactly with Switch’s zones. Consequently I assigned their forecasted loads to my zones by overlaying the two maps, then assigning fractions of each of the Energy Commission’s zones to the Switch zones, proportional to the population of their intersecting areas.

Error! Reference source not found. shows the average and peak loads in each load zone in 2004 and the average annual growth rates from then until 2024.

Table SI.5. Electricity loads and annual growth rate in each load zone, 2004–24

Load Zone	2004 Average Load (MW)	2004 Peak Load (MW)	Annual Growth of Peak Load (linear)	Annual Growth of Average Load (linear)
Humboldt	99	155	1.7%	2.5%
North Coast	131	231	1.7%	2.5%
Geysers	310	511	1.3%	2.4%
PG&E North	1,935	3,319	1.6%	2.3%
San Francisco	796	1,146	0.8%	0.3%
Other Bay Area	4,244	7,002	1.0%	1.5%
Sierra	264	558	1.8%	2.7%
PG&E South	2,132	3,658	1.8%	2.6%
Fresno	1,276	2,634	2.0%	1.8%
ZP26	1,028	1,790	1.7%	2.0%
Other SCE	9,241	16,280	1.8%	1.7%
Orange	2,821	4,928	1.1%	0.9%
San Diego	2,354	4,088	1.7%	2.2%
Sacramento	1,240	2,672	1.8%	2.4%
Los Angeles	3,020	5,418	0.6%	0.6%
Imperial	373	840	3.6%	3.6%

Reschedulable Electricity Loads (Plug-in Hybrid Electric Vehicles). The base case model runs for California don't include any interruptible loads. However, some sensitivity cases include reschedulable loads that might occur if half of California's current gasoline vehicle fleet were converted to electric or plug-in hybrid-electric vehicles (PHEVs). This corresponds to an additional average load of 10.5 GW, which is phased in from zero in the first study period to the full level in the last study period.[6] The geographic distribution of these loads is assumed to be proportional to the already forecast annual electric loads (this acts as a crude proxy for the density of population and economic activity).

SI.4. FUEL PRICES

Forecasts of the price of natural gas, uranium and coal in future years ($\text{fuel\_cost\_hourly}_{f,h}$) are taken

[6] I arrive at this 10.5 GW figure as follows. The U.S. Energy Information Administration reports that California used 383,178,000 barrels of gasoline in 2006. This corresponds to a heat content of 67 GW. I assume that gasoline vehicles are 25 percent efficient at converting this heat to work, so that this gasoline does 16.8 GW of work. Then I assume that electric vehicles are 80 percent efficient at converting electricity to work, so that they will need 20.9 GW of electricity to do the same amount of work. I then divide by 2 to obtain the target above. This calculation does not account for the additional efficiency improvements that would be obtained when this part of the fleet is converted from traditional gasoline engines to hybrid drive systems. If those improvements are included, this amount of electricity may be enough to serve about three-quarters of the current gasoline vehicle fleet, or half of a larger, future fleet. I consider only gasoline vehicles because they are generally used for shorter periods each day than diesel vehicles, making them better candidates for electrification.

from the California Energy Commission's Cost of Generation Study {Klein, 2010 #342}{Klein, 2010 #360}. I use the mid-range California-wide price for most of the work described here, and low and high forecasts for sensitivity analysis. These prices are shown in Table SI.6 for each investment period.

Table SI.6. Forecast prices for natural gas, nuclear fuel and coal (2012$/MMBtu)

	Gas		Uranium		Coal	
year	mid	low-high range	mid	low-high range	mid	low-high range
2012	$7.87	$4.95 – $11.39	$0.72	$0.62 – $0.83	$2.20	$1.60 – $3.82
2016	$9.09	$5.21 – $13.56	$0.80	$0.68 – $0.91	$2.24	$1.64 – $3.90
2020	$10.78	$5.84 – $16.41	$0.85	$0.77 – $0.93	$2.26	$1.65 – $3.94
2024	$12.23	$6.37 – $18.92	$0.89	$0.77 – $1.00	$2.27	$1.66 – $3.95

SI.5. NEW GENERATORS

SI.5.1. Model Components for New Power Plants

New generators participate in Switch's load-serving and reserve margin constraints via $\text{NewGenOutput}_{z,h}$ and $\text{NewGenMaxOutput}_{z,h}$. These are defined as

$$\begin{aligned}\text{NewGenOutput}_{\substack{z \in \text{LOAD\_ZONES},\\ h \in \text{HOURS}}} = & \sum_{(z,t,s,o) \in \text{PROJ\_DISPATCH}} \text{DispatchGen}_{z,t,s,o,h} \\ & + \sum_{\substack{(z,t,s,o,v,h) \in \\ \text{PROJ\_INTERMITTENT\_VINTAGE\_HOURS}}} \text{InstallGen}_{z,t,s,o,v} \cdot \left(1\text{-forced\_outage\_rate}_t\right) \cdot \text{cap\_factor}_{z,t,s,o,h}\end{aligned}$$

$$\begin{aligned}\text{NewGenMaxOutput}_{\substack{z \in \text{LOAD\_ZONES},\\ h \in \text{HOURS}}} = & \sum_{\substack{(z,t,s,o,v,h) \in \\ \text{PROJ\_DISPATCH\_VINTAGE\_HOURS}}} \text{InstallGen}_{z,t,s,o,v} \\ & + \sum_{\substack{(z,t,s,o,v,h) \in \\ \text{PROJ\_INTERMITTENT\_VINTAGE\_HOURS}}} \text{InstallGen}_{z,t,s,o,v} \cdot \text{cap\_factor}_{z,t,s,o,h}\end{aligned}$$

Note: in cases where an indexing variable appears on both sides of an equation, I assume values on the right are chosen to match the value on the left. That is,

$$x_{a \in A} = \sum_{(a,b) \in AB} y_{a,b} \quad \text{is equivalent to} \quad x_{a \in A} = \sum_{(a',b) \in AB:\, a' = a} y_{a',b}$$

This matches the convention used by the AMPL programming language and simplifies the documentation somewhat. I use a similar convention when the same indexing variable appears in both an inner and outer sum, or when a constraint is repeated for many different plants or times.

The hourly cost components for new generators are given by

$$\text{NewGenCapitalCostPerHour}_{h \in \text{HOURS}} \equiv \sum_{\substack{(z,t,s,o,v,h) \in \\ \text{PROJ\_VINTAGE\_HOURS}}} \text{InstallGen}_{z,t,s,o,v} \cdot \text{capital\_cost\_per\_hour}_{z,t,s,o,v}$$

$$\text{NewGenFixedCostPerHour}_{h \in \text{HOURS}} \equiv \sum_{\substack{(z,t,s,o,v,h) \in \\ \text{PROJ\_VINTAGE\_HOURS}}} \text{InstallGen}_{z,t,s,o,v} \cdot \text{fixed\_cost\_per\_hour}_{z,t,s,o,v}$$

$$\text{NewGenVariableCostPerHour}_{h \text{ in HOURS}} \equiv \sum_{(z,\,t,\,s,\,o) \text{ in PROJ\_DISPATCH}} \text{DispatchGen}_{z,t,s,o,h} \cdot \text{variable\_cost\_per\_mwh}_{t,h}$$

$$\text{NewGenCarbonCostPerHour}_{h \text{ in HOURS}} \equiv \sum_{(z,\,t,\,s,\,o) \text{ in PROJ\_DISPATCH}} \begin{pmatrix} \text{DispatchGen}_{z,t,s,o,h} \cdot \text{heat\_rate}_t / 1000 \\ \cdot\ \text{carbon\_content}_{\text{fuel}_t} \cdot \text{carbon\_cost} \end{pmatrix}$$

These in turn depend on a number of sets, decision variables and parameters, shown in Tables .7–.9.

Table SI.7. Sets used to define new generation projects

Set Name	Indexing variables	Description	Definition
PROJECTS	(*z,t,s,o*)	New power generation projects that can be built; these are defined by the load zone where they would be built (*z*), the generation technology (*t*), the specific site (*s*) of the facility within the load zone, and, optionally, the orientation of the facility (*o*)	PROJ_ANYWHERE ∪ PROJ_INTERMITTENT ∪ PROJ_ RESOURCE_LIMITED
PROJECT_ VINTAGES	(*z,t,s,o,v*)	Possible construction years (*v*) for new projects (*z,t,s,o*)	{(z, t, s, o) ∈ PROJECTS, v ∈ VINTAGE_YEARS: v ≥ min_ vintage_year$_t$}
PROJ_VINTAGE_ HOURS	(*z,t,s,o,v,h*)	Valid combinations of construction year (*v*) and operational hour (*h*) for new projects (*z,t,s,o*).	{(z, t, s, o, v) in PROJECT_VINTAGES, h in HOURS: v ≤ period$_h$ < project_end_year$_{t,v}$}
PROJ_ INTERMITTENT	(*z,t,s,o*)	New generation projects that would provide an intermittent supply of power (e.g., wind or solar)	All projects for which hourly capacity factors are specified and intermittent$_{z,t,s,o}$ = 1.
PROJ_ RESOURCE_ LIMITED	(*z,t,s,o*)	New generation projects that can only be scaled to a finite size (e.g., solar or geothermal)	All projects for which max_capacity$_{z,t,s,o}$ values are specified.
PROJ_ANYWHERE	(*z,t,s,o*)	New generation projects that can be built in unlimited size at the center of each load zone (e.g., natural gas plants); this includes all technologies that don't have site-specific capacity factors or size limits.	{(z ∈ LOAD_ZONES, t ∈ TECHNOLOGIES, s = generic, o = generic): not intermittent$_t$ and not resource_limited$_t$}
PROJ_ INTERMITTENT_ VINTAGE_HOURS	(*z,t,s,o,v,h*)	Valid combinations of construction year (*v*) and operational hour (*h*) for new intermittent generation projects (*z,t,s,o*).	{(z, t, s, o) ∈ PROJ_INTERMITTENT, v ∈ VINTAGE_YEARS, h ∈ HOURS: min_vintage_year$_t$ ≤ v ≤ period$_h$ < project_end_ year$_{t,v}$}
PROJ_DISPATCH	(*z,t,s,o*)	New projects that would provide a dispatchable supply of power	All projects that are not intermittent: PROJECTS \ PROJ_ INTERMITTENT
PROJ_DISPATCH_ VINTAGE_HOURS	(*z,t,s,o,v,h*)	Valid combinations of construction year (*v*) and operational hour (*h*) for new dispatchable generation projects (*z,t,s,o*).	{(z, t, s, o) ∈ PROJ_DISPATCH, v ∈ VINTAGE_YEARS, h ∈ HOURS: min_vintage_year$_t$ ≤ v <= period$_h$ < project_end_ year$_{t,v}$}

Table SI.8. Decision variables for new generation projects

Decision Variable Name	Indexing set	Description
InstallGen	PROJECT_VINTAGES	Number of MW of capacity to install in each new project at the start of each investment period.
DispatchGen	PROJ_DISPATCH × HOURS	Number of MW of power to generate from each new, dispatchable power project during each hour.

Table SI.9. Parameters describing new generation projects

Parameter Name	Indexed over	Description	Definition
cap_factor	PROJ_ INTERMITTENT_ HOURS	Capacity factor (power production as a fraction of plant size) expected from each intermittent generation project (*z,t,s,o*) during each hour (*h*).	Specified exogenously.
capital_cost_ annual_ payment	PROJECT_ VINTAGES	The repayment required for the capital investment in each possible generation project, per kW of capacity, expressed as an annual cost during the life of the project.	$\text{capital\_cost\_annual\_payment}_{(z,t,s,o,v)\ \text{in PROJECT\_VINTAGES}} = \left(\frac{\text{finance\_rate}_t}{1 - \left(1 + \text{finance\_rate}_t\right)^{-\text{max\_age\_years}_t}} \right) \cdot \text{capital\_cost\_proj}_{z,t,s,o,v}$
capital_cost_ per_hour	PROJECT_ VINTAGES	The capital repayment required for each possible generation project, per MW of capacity, expressed as an hourly cost during the life of the project.	$\text{capital\_cost\_per\_hour}_{(z,t,s,o,v)\ \text{in PROJECT\_VINTAGES}} = \text{capital\_cost\_annual\_payment}_{z,t,s,o,v} \cdot 1000 / \text{hours\_per\_year}$
capital_cost_ by_vintage	TECHNOLOGIES × VINTAGE_ YEARS	The cost of building each available power plant technology, during each future year (per kW of nameplate capacity).	Specified exogenously.
capital_cost_ proj	PROJECT_ VINTAGES	The projected cost of building each possible generation project, per kW of capacity.	$\text{capital\_cost\_proj}_{(z,t,s,o,v)\ \text{in PROJECT\_VINTAGES}} = \text{capital\_cost\_by\_vintage}_{t,v} + \text{connect\_length\_km}_{z,t,s,o} \cdot \text{transmission\_cost\_per\_mw\_km} / 1000 + \text{connect\_cost\_per\_kw\_generic}_t + \text{connect\_cost\_per\_kw}_{z,t,s,o}$
carbon_ content	FUELS	Greenhouse gas emissions per unit of fuel (tonnes CO_2e per MMBtu)	Specified exogenously.
connect_cost_ per_kw	PROJECTS	The cost of grid upgrades required to integrate each potential generator project into the power system. This is set to zero if generic costs are given.	Specified exogenously.
connect_cost_ per_kw_ generic	TECHNOLOGIES	The cost of grid upgrades required to integrate a new power plant using technology *t* into the power system. This is set to zero if project-specific costs are given.	Specified exogenously.
connect_ length_km	PROJECTS	The distance from each potential generation project to the main electric grid.	Specified exogenously.
finance_rate	TECHNOLOGIES	Finance rate used to amortize capital costs over the life of generation projects.	Specified exogenously.
fixed_cost_ per_hour	PROJECT_ VINTAGES	The fixed operation and maintenance costs of power projects built during each investment period, expressed as an hourly cost per MW of capacity, during all hours of the plant's life.	$\text{fixed\_cost\_per\_hour}_{(z,t,s,o,v)\ \text{in PROJECT\_VINTAGES}} = \text{fixed\_o\_m}_t \cdot 1000 / \text{hours\_per\_year}$
fixed_o_m	TECHNOLOGIES	The fixed operation & maintenance cost for new power plants using technology *t* (2012$ per kW of	Specified exogenously.

		capacity per year).	
fuel	TECHNOLOGIES	Type of fuel used by each type of power plant	Specified exogenously.
fuel_cost_ hourly	FUELS × HOURS	Forecast cost of each type of fuel during each hour of the study, in base-year dollars per MMBtu.	Specified exogenously. See “Fuel Prices” section.
heat_rate	TECHNOLOGIES	Heat rate (1/efficiency) for new power plants based on each technology, in units of MMBtu per kWh.	Specified exogenously.
intermittent	PROJECTS	Set to 1 if a project provides an intermittent supply of power, 0 if the project is dispatchable.	Specified exogenously.
resource_ limited	TECHNOLOGIES	Set to 1 if a technology can only be scaled to a finite size at each site; otherwise 0.	Specified exogenously.
max_capacity	PROJ_ RESOURCE_ LIMITED	Maximum size of each new generation project (in MW). (Can be developed incrementally over time.)	Specified exogenously.
max_age_ years	TECHNOLOGIES	Number of years that a new generation can operate before being retired.	Specified exogenously.
transmission_ cost_per_mw_ km	(single value)	The cost to install additional transfer capability, per MW of capacity, per km spanned.	Specified exogenously; see Transmission section.
variable_cost_ per_mwh	TECHNOLOGIES × HOURS	The variable cost per MWh of electricity produced by technology t during hour h. This includes fuel and variable O&M.	$\text{variable\_cost\_per\_mwh}_{t \in \text{TECHNOLOGIES}, h \in \text{HOURS}} =$ $\text{variable\_o\_m}_t + \text{heat\_rate}_t / 1000 \cdot \text{fuel\_cost\_hourly}_{\text{fuel}_t, h}$
variable_o_m	TECHNOLOGIES	Variable operation and maintenance costs of power projects (e.g., wear and tear costs), per MWh of electricity generated.	Specified exogenously.

Two additional constraints govern the construction and operation of new power generation projects:

The system can only dispatch as much power from each project during each hour as has been built previously; this is further limited by the amount that is expected to be offline on average:

subject to (for (z, t, s, o) in PROJ_DISPATCH, h in HOURS):

$$\text{DispatchGen}_{z,t,s,o,h} \le (1 - \text{forced\_outage\_rate}_t) \cdot \sum_{\substack{(z,t,s,o,v,h) \in \\ \text{PROJ\_DISPATCH\_VINTAGE\_HOURS}}} \text{InstallGen}_{z,t,s,o,v}$$

Note that this constraint is repeated for every project and hour; in each instance, z, t, s, o and h are held constant, and the sum indexes over matching vintages.

Limits on the size of each project must be respected, where applicable:

subject to (for (z, t, s, o) in PROJ_RESOURCE_LIMITED):

$$\sum_{(z,t,s,o,v) \in \text{PROJECT\_VINTAGES}} \text{InstallGen}_{z,t,s,o,v} \le \text{max\_capacity}_{z,t,s,o};$$

Note: As currently formulated, new projects cannot be recommissioned if they are retired during the study period, but this is not a problem because the study period is too short to build, retire and recommission any of the technologies under consideration. Future changes to Switch will allow recommissioing of projects, which will make it possible to consider longer periods, shorter-lived projects or economically-driven repowering of projects.

SI.5.2. Technological Options

For this work, Switch is able to install four different types of generator (TECHNOLOGIES): gas-fired combined cycle combustion turbines, wind farms, distributed solar photovoltaic modules, or solar thermal troughs (without storage). Simple-cycle combustion turbines are excluded because they are forecast to have higher capital costs and lower efficiencies than combined cycle plants (see below); consequently Switch would never select them for installation.

SI.5.3. Capital Cost for New Power Plants

Future capital costs of wind, solar thermal electric and natural gas power plants are taken from the California Energy Commission's Cost of Generation Model {Klein, 2010 #342;Klein, 2010 #360}. This model uses a base capital cost which decreases over time for renewable energy projects. The model then inflates this cost using an allowance for funds used during construction (AFUDC) of 3–4.5%. An additional inflator (totaling 8.8%) is applied to convert costs from 2009$ to 2012$.

The cost of distributed solar PV systems is calculated by fitting an exponential trend to the cost of solar PV systems installed in the U.S. in 1998–2009 {Barbose, 2010 #366}, converted into 2012 dollars. This trend is $\$11{,}978 \times 0.964^{(\text{year}-1997)}$ (i.e., a 3.6%/year decline).

Capital costs for each technology for each year of the study are shown in Table .10. These costs exclude state and federal tax credits, in order to judge the least-cost policy in the absence of these incentives. They also exclude property tax and land acquisition costs, which are assumed to be neglible relative to the cost of each power plant.

Table SI.10. Capital cost of new generation projects in California (capital_cost_by_vintage$_{t,v}$, 2012$/kW)

Year	Combined-Cycle Gas Turbine (CCGT)		Solar Thermal Electric Troughs		Distributed Solar PV (DistPV)		On-Shore Wind	
	Base	Range	Base	Range	Base	Range	Base	Range
2012	$1,174	$753–$1588	$3,494	$2,600–$3,812	$6,980	$6,693–$7,776	$2,199	$1,431–$3,603
2016	$1,174	$753–$1588	$3,033	$2,202–$3,437	$6,044	$5,480–$7,776	$2,128	$1.365–$3,580
2020	$1,174	$753–$1588	$2,636	$1,877–$3,098	$5,234	$4,487–$7,776	$1,975	$1,235–$3,518
2024	$1,174	$753–$1588	$2,303	$1,624–$2,796	$4,532	$3,673–$7,776	$1,741	$1,040–$3,417

SI.5.4. Interconnection Cost for New Power Plants

The cost of connecting new power plants to the electric grid is estimated as follows.

I assume that new central-station fossil plants can be built near a major interconnection point. Consequently, the cost of connecting them is the average of the "linear" cost of connection that Klein and Rednam (14) found in surveys of recently built power plants. This is $64/kW for CCGT plants and $10/kW for simple-cycle plants.

For wind farms, I assume that transmission capacity must be built from the wind farm site to the nearest interconnection point reported by the state's three investor-owned utilities in their Transmission Ranking Cost Reports (TRCRs) (22-24). This transmission capacity is assumed to cost the same as inter-zonal transmission capacity ($1,000/MW-km; see the Transmission section). I also assume that the cost of intra-grid upgrades to support each of these interconnections is proportional to the largest upgrade considered in the TRCR for that location. For example, SCE's TRCR indicates that up to 8.4 GW can be connected to its new Kern County (Tehachapi) substations, at a total cost of $2.6 billion, so I assume that it will cost $2.6 B / 8.4 GW, or $311 per kW to connect any new wind farms there, in addition to the cost of building a transmission line from the wind farm to the substation. The interconnect points and costs used for this work are shown in **Error! Reference source not found.**. The capacity-weighted average cost of grid upgrades at wind interconnection points is $268/kW, and the average distance from wind farms to the interconnect points is 53 km, resulting in an additional cost averaging $58/kW for transmission capacity from the wind farm to the interconnect point.

Table SI.11. Interconnect cost and distance for wind farms (connect_cost_per_kw, connect_length_km)

Load Zone	Interconnect Name	Max. Wind Studied in TRCR (MW)	Max. Wind in Switch (MW)	Inter-connect Cost ($/kW)	Avg. Trans-mission Dis-tance (km)	Transmis-sion Dis-tance Range (km)
PG&E North	Caribou	1050	6630	408	69	20 – 144
PG&E North	Cottonwood	1000	120	331	48	45 – 50
PG&E North	Delta	300	2370	127	110	21 – 166
PG&E North	Pit	1650	6180	285	84	2 – 161
PG&E North	Round Mountain	1150	1680	615	86	22 – 95
PG&E North	Table Mountain	900	120	429	82	79 – 84
PG&E North	Vaca Dixon	1000	750	286	32	24 – 41
Sierra	Summit	200	4890	190	53	1 – 135
PG&E South	Los Banos	750	120	65	54	13 – 95
PG&E South	Tesla	2000	660	65	12	2 – 19
Fresno	Gregg	1000	1890	132	135	122 – 163
Fresno	Wilson	600	330	112	140	137 – 142
ZP26	Midway	4000	30	75	64	64 – 64
Other SCE	Kern County	8385	14760	311	31	1 – 103
Other SCE	Inyokern Area	820	15090	299	43	1 – 132
Other SCE	Kramer Area	4681	3870	160	62	50 – 90
Other SCE	Mountain Pass	1177	630	93	30	9 – 98
Other SCE	Victoville Area	329	5550	198	25	3 – 72
Other SCE	Devers	5170	3480	211	22	1 – 51
Other SCE	El Dorado/Mohave	4500	180	422	69	53 – 106
Other SCE	Pisgah Area	6506	15000	238	58	10 – 95
Other SCE	Salton Sea Area	3599	180	248	53	39 – 57
San Diego	SDGE C1	1752	60	0	23	23 – 24
San Diego	SDGE C3	1250	1860	254	40	9 – 92
Total or Average			**86430**	**268**	**53**	**1 – 166**

For solar thermal electric troughs, I assume that transmission capacity must be built from the hypothetical solar project location (i.e., the CIMIS monitoring site) to the nearest 230 kV or higher substation in the power system. These lines are also assumed to cost $1000/MW-km. I further assume that grid upgrades at the interconnect point would have a cost equal to the simple average among all interconnect points reported in the IOU TRCRs. This amounts to $233 per kW.

I do not assume any interconnect cost for distributed photovoltaic systems, and indeed, these systems are assumed to reduce the need for intra-zone upgrades, if they help reduce the peak electric load within their zone (see section SI.9.2).

SI.5.5. California Wind Resources

The location, size and hourly power production (cap_factor) for potential wind power sites are taken from datasets developed for the Western Wind and Solar Integration Study {GE Energy, 2010 #251}. produced at each existing or potential wind farm site during every hour of 2002–04. This project used a numerical weather model with a large body of historical weather data to produce a comprehensive dataset of power production that would have occurred at potential wind farm locations throughout the western U.S. every 10 minutes in 2004–06. For this study, I used data for 2004, aggregated to an hourly production level, coinciding with the available load data.

The WWSIS dataset includes 2881 potential on-shore wind farms of 30 MW each. In order to reduce computation time in Switch, I clustered together wind farms that had the same interconnect point and average power production (rounded to the nearest 1%). This produced 306 wind farms with sizes ranging from 30 to 1830 MW (averaging 282 MW). This is a mildly conservative approach, since it forces Switch to install a mix of wind farms in each resource area, instead of choosing only the best-timed sites in each region.

SI.5.6. California Solar Resources

SI.5.6.1. California Irrigation Management Information System

Hourly irradiances for solar troughs and photovoltaic systems are derived from a dataset of hourly horizontal global shortwave irradiance measurements, developed by the California Irrigation Management Information System (CIMIS). This program, operated by the California Department of Water Resources, collects a variety of meteorological data from a network of about 200 monitoring stations, for use in modeling evapotranspiration throughout the state of California (34). I estimated hourly capacity factors for solar troughs and photovoltaic systems based on hourly irradiance measurements for 117 stations that had collected data during at least 90% of the hours between November 2002 and October 2004. A small number of missing hours were filled in with the average of the previous and next hour.

SI.5.6.2. Solar Thermal Trough Power Production

Solar thermal electric troughs are assumed to be installed at exactly the location of the CIMIS measurement systems. This is a conservative assumption, because there are likely to be good solar resources closer to load centers.

I first calculated the direct beam irradiance expected on a solar thermal trough each hour, based on the irradiance measured on a horizontal surface. I then calculated the capacity factor from this. The irradiance calculation is based Perez et al.'s anisotropic sky model, as cited in Duffie and Beckman {, 1991 #367}. This model first estimates a sky clarity parameter based on the measured horizontal flat-plate irradiance, latitude, longitude and solar angle. It then uses this parameter to calculate various components of radiation: direct beam, isotropic diffuse (from sky dome), circumsolar diffuse (near beam), diffuse from the horizon, and ground reflection.

To convert this hourly irradiance into an hourly capacity factor, I first assume that solar thermal troughs receive the amount of direct-beam radiation that would be incident on a one-axis, horizontal tracking surface, with a north-south axis, as calculated via the Perez model. I further assume that the capacity factor for these facilities would be 100% under 1000 W irradiance, that it scales linearly with irradiance, and that these systems have no ability to store energy between hours.

SI.5.6.3. Photovoltaic Power Production

I assume that solar photovoltaic systems can be installed anywhere in extended "solar zones" around each CIMIS station. These solar zones are defined as follows. I first assign each CIMIS station to one of CIMIS's reference evapotranspiration zones, using GIS data provided by the CIMIS (35). I next assume that all photovoltaic systems in the same evapotranspiration zone and within 200 km of each station have the same hourly solar conditions. The stations and their corresponding land areas are shown in Figure 2.

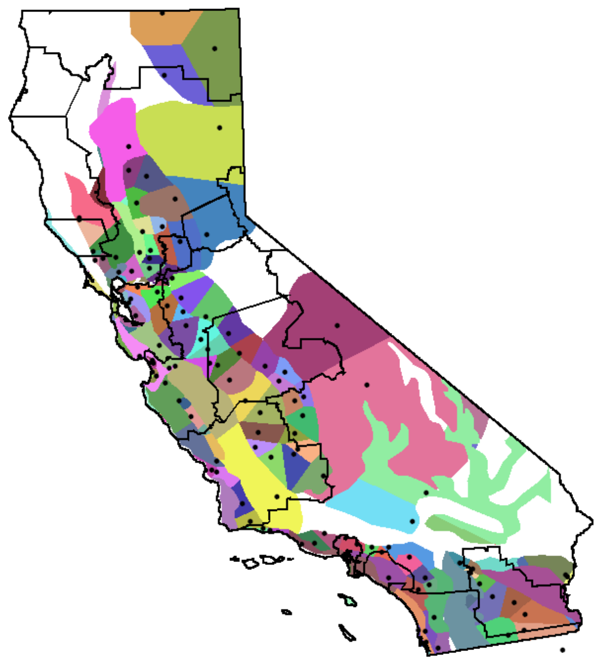

Figure 2. Solar measurement stations and corresponding land areas for photovoltaic installations (colored regions). Load zones are shown with black borders, for reference.

I then split the solar zones where they cross load zone borders, and estimate the population in each of these solar-load zone combinations, based on 2000 census data. I assume that the roof area in each of these solar-load zones is proportional to the population in that region, and that there is enough roof area to install 1 kW of solar panels per person.

Switch is allowed to choose among three panel orientations in each solar zone. These face directly toward the sun at 12:30, 2:30 or 4:30 pm, on the vernal and autumnal equinoxes. I assume that one twelfth of the available roof area faces in each of these directions (or close enough to treat as if it does). Then I use the same directional irradiance parameters as in section SI.5.6.2 to calculate the total irradiance on each tilted panel, during each hour.

The nameplate rating of photovoltaic systems usually indicates the amount of power they would produce under bright-sun conditions, corresponding to 1000 W/m^2 of radiation at standard atmospheric conditions. The power output from a solar module also generally varies proportionately with the radiation striking its surface (neglecting the effect of temperature). Consequently, I use a simple model for the capacity factor of solar PV installations during any hour as a function of the total radiation striking the surface of the panel:

$$\text{capacity factor} = \frac{\text{power output}}{\text{rated power}} = \frac{\text{irradiance}}{1000\ \text{W}/\text{m}^2}$$

SI.5.7. Other Properties of New Power Plants

Most other properties of new power plants are taken from the CEC's Cost of Generation Model {Klein, 2010 #342;Klein, 2010 #360}, with costs updated to 2012 dollars. (However, O&M costs for solar photovoltaic projects are based on the fixed O&M reported for single-axis tracking photovoltaic systems in the 2007 version of this model{Klein, 2007 #16}, updated to 2012 dollars.) These properties are listed in Table .12.

Table SI.12. Other properties of new power plants

Parameter Name	Description	CCGT	Trough	Wind	DistPV
$min\_vintage\_year_t$	First year when technology *t* can be installed	2012	2012	2012	2012
$max\_age\_years_t$	Age of project at retirement	20	20	30	25
$fixed\_o\_m_t$	Fixed O&M (2012$/kW·y)	8.46	74.03	14.91	30.00
$variable\_o\_m_t$	Variable O&M (2012$/MWh)	3.29	0.00	5.99	0.00
$fuel_t$	Fuel used by plant	Gas	Solar	Wind	Solar
$heat\_rate_t$	Heat rate (1/efficiency, Btu / kWh)	7050			
$forced\_outage\_rate_t$	Forced outage rate	0.022	0.016	0.02	0.003
$scheduled\_outage\_rate_t$	Scheduled outage rate	0.06	0.022	0.014	0
$intermittent_t$	Intermittency flag	0	1	1	1
$resource\_limited_t$	Finite resource flag	0	0	1	1

SI.5.8. Projected Levelized Cost of Power

Figure SI.3 combines the information presented in this section, to show the levelized cost of power from generation plants of each type that can be developed in Switch. For the purposes of this figure, combined cycle gas plants are assumed to run at a 47 percent capacity factor, wind farms have 34 percent capacity factor, solar thermal troughs have a 27 percent capacity factor, and photovoltaic systems have a 21 percent capacity factor. These are typical values for the systems installed by the Switch model. Interconnect costs are also added as follows: $64/kW for CCGT plants, $326/kW for wind projects, and $250/kW for solar thermal troughs. These values are only used for illustration here; during the optimization, Switch uses site-specific values for these parameters.

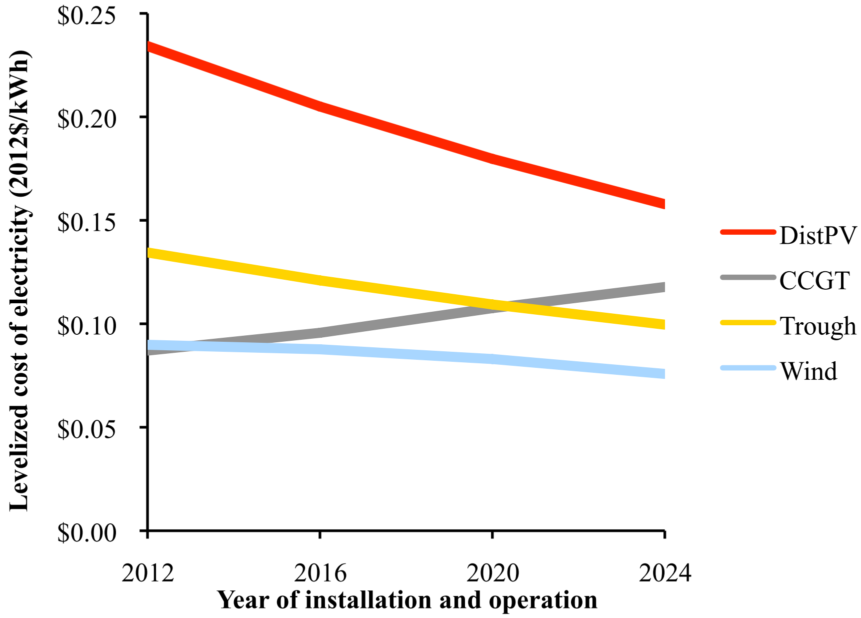

Figure SI.3. Projected levelized costs of electricity from generation technologies available for installation in Switch

SI.6. EXISTING NON-HYDRO GENERATORS

SI.6.1. Model components for existing power plants

The key decisions for existing plants are whether to operate them at all during each investment period (OperateEPDuringYear), and whether to operate them during each individual hour (DispatchEP). Mothballing capacity during an investment period (OperateEPDuringYear < 1) allows Switch to avoid paying the fixed O&M costs for that capacity (though the plant's capital recovery requirements must still be paid). However, capacity that has been mothballed cannot contribute to the system's load-serving or reserve margin requirements.

Existing generators contribute to Switch's load-serving and reserve margin constraints via ExistingGenOutput$_{z,h}$ and ExistingGenMaxOutput$_{z,h}$. These are defined as

$$\text{ExistingGenOutput}_{\substack{z \in \text{LOAD\_ZONES}, \\ h \in \text{HOURS}}} = \sum_{(z,e,h) \in \text{EP\_DISPATCH\_HOURS}} \text{DispatchEP}_{z,e,h}$$

$$\text{ExistingGenMaxOutput}_{\substack{z \in \text{LOAD\_ZONES}, \\ h \in \text{HOURS}}} = \sum_{\substack{(z,e,h) \in \\ \text{EP\_DISPATCH\_HOURS}}} \text{OperateEPDuringYear}_{z,e,\text{period}_h} \cdot \left(1\text{-ep\_scheduled\_outage\_rate}_{z,e}\right) \cdot \text{ep\_size\_mw}_{z,e}$$

In these equations, individual plants (or aggregated "virtual plants") are indexed by load zone (z) and an ID for each plant (e) within that zone. Switch uses the scheduled outage rate to set the level of output from baseload plants during each investment period based on their historical operation level (see below), so this is also incorporated into the calculation of each plant's contribution toward the reserve margin constraint.

The hourly cost components for existing power plants are given by

$$\text{ExistingGenCapitalCostPerHour}_{z,h} = \sum_{\substack{(z,e,p)\in \text{EP\_PERIODS}:\\ p = \text{period}_h}} \text{ep\_size\_mw}_{z,e} \cdot \text{ep\_capital\_cost\_per\_hour}_{z,e}$$

$$\text{ExistingGenFixedCostPerHour}_{z,h} = \sum_{\substack{(z,e,p)\in \text{EP\_PERIODS}:\\ p = \text{period}_h}} \text{OperateEPDuringYear}_{z,e,p} \cdot \text{ep\_size\_mw}_{z,e} \cdot \text{ep\_fixed\_cost\_per\_hour}_{z,e}$$

$$\text{ExistingGenVariableCostPerHour}_{z,h} = \sum_{\substack{(z,e,h) \in\\ \text{EP\_DISPATCH\_HOURS}}} \text{DispatchEP}_{z,e,h} \cdot \text{ep\_variable\_cost\_per\_mwh}_{z,e,h}$$

$$\text{ExistingGenCarbonCostPerHour}_{z,h} = \sum_{\substack{(z,e,h) \in\\ \text{EP\_DISPATCH\_HOURS}}} \text{DispatchEP}_{z,e,h} \cdot \text{ep\_heat\_rate}_{z,e} \cdot \text{carbon\_content}_{\text{ep\_fuel}_{z,e}} \cdot \text{carbon\_cost}$$

These in turn depend on sets, decision variables and parameters shown in Tables SI.13–SI.15.

Table SI.13. Sets used to define existing power plants

Set Name	Indexing variables	Description	Definition
EXISTING_ PLANTS	(*z*,*e*)	Existing power plants, identified by the load zone containing the plant (*z*) and a unique ID for each plant (*e*)	Specified exogenously.
EP_DISPATCH_ HOURS	(*z*,*e*,*h*)	Hours (*h*) when existing plants (*z*,*e*) could be dispatched	EP_DISPATCH_HOURS = {(z, e) ∈ EXISTING_PLANTS, h ∈ HOURS: $\text{ep\_vintage}_{z,e}$ <= period_h < $\text{ep\_end\_year}_{z,e}$}
EP_PERIODS	(*z*,*e*,*p*)	Investment periods (*p*) when existing plants (*z*,*e*) could be run	EP_PERIODS = {(z, e) ∈ EXISTING_PLANTS, p ∈ PERIODS: $\text{ep\_vintage}_{z,e}$ <= p < $\text{ep\_end\_year}_{z,e}$}

Table SI.14. Decision variables for existing power plants

Decision Variable Name	Indexing Set	Description
OperateEPDuringYear	EP_PERIODS	Fraction of existing power plant capacity to keep online (instead of mothballing) during each investment period; can be fractional in the range of 0-1 but usually takes a value of 0 or 1. Can be raised or lowered each period.
DispatchEP	EP_DISPATCH_HOURS	Number of MW of power to generate from each existing power plant during each hour

Table SI.15. Parameters describing existing power plants

Parameter Name	Indexing Set	Description	Definition
ep_size_mw	EXISTING_ PLANTS	Maximum possible output from each existing plant	Specified exogenously.
ep_capital_cost_ per_hour	EXISTING_ PLANTS	The carrying cost for existing plants, converted into an hourly cost during all hours until the plant retires.	$\text{ep\_capital\_cost\_per\_hour}_{(z,e)\in\text{EXISTING\_PLANTS}} = \text{ep\_capital\_cost\_annual\_payment}_{z,e} \cdot 1000 / \text{hours\_per\_year}$
ep_finance_rate	(single value)	Finance rate used to amortize the capital costs of existing power plants.	Specified exogenously.
ep_capital_cost_ annual_payment	EXISTING_ PLANTS	The capital repayment required for each existing power plant, per kW of capacity, expressed as an annual cost during the life of the project.	$\text{ep\_capital\_cost\_annual\_payment}_{(z,\,e)\text{ in EXISTING\_PLANTS}} = \text{ep\_overnight\_cost}_{z,e} \cdot \dfrac{\text{ep\_finance\_rate}}{1-\left(1+\text{finance\_rate}_{ccgt}\right)^{-\text{ep\_max\_age\_years}_{z,e}}}$
ep_max_age_ years	EXISTING_ PLANTS	Number of years that a power plant can operate before being retired.	Specified exogenously.
ep_fixed_cost_ per_hour	EXISTING_ PLANTS	Fixed O&M costs of existing plants if they are not mothballed; converted into an hourly cost.	$\text{ep\_fixed\_cost\_per\_hour}_{(z,\,e)\in\text{EXISTING\_PLANTS}} = \text{ep\_fixed\_o\_m}_{z,e} \cdot 1000 / \text{hours\_per\_year}$
ep_variable_ cost_per_mwh	EP_DISPATCH_ HOURS	The variable cost per MWh produced by each plant. Includes fuel and variable O&M.	$\text{ep\_variable\_cost\_per\_mwh}_{\substack{(z,e)\text{ in EXISTING\_PLANTS,}\\ h\text{ in HOURS}}} = \text{ep\_variable\_o\_m}_{z,e} + \text{ep\_heat\_rate}_{z,e}/1000 \cdot \text{fuel\_cost\_hourly}_{\text{ep\_fuel}_{z,e}}$
ep_overnight_ cost	EXISTING_ PLANTS	Approximate cost of building existing plants; used to calculate the repayments required for the sunk cost of existing plants.	Specified exogenously.
ep_variable_o_ m	EXISTING_ PLANTS	Variable operation and maintenance costs of power plants (e.g., wear and tear costs), per MWh of electricity generated.	Specified exogenously.
fuel_cost_hourly	FUELS × HOURS	Forecast cost of each type of fuel during each hour of the study, in base-year dollars per MMBtu.	Specified exogenously. See “Fuel Prices” section.
carbon_content	FUELS	Greenhouse gas emissions per unit of fuel (tonnes CO_2e per MMBtu)	Specified exogenously.
ep_heat_rate	EXISTING_ PLANTS	Heat rate (1/efficiency) for each power plant (Btu of fuel input per kWh of electricity output)	Specified exogenously.
ep_baseload	EXISTING_ PLANTS	Set to 1 if a generation project must run at a constant output level, 0 if it can be varied.	Specified exogenously.

ep_fuel	EXISTING_ PLANTS	Type of fuel used by each power plant	Specified exogenously.
ep_vintage	EXISTING_ PLANTS	Year when power plant was built	Specified exogenously.
ep_end_year	EXISTING_ PLANTS	First year when the power plant will not be available due to retirement. Plants are assumed to be available until the end of the study period in which they reach their retirement age.	$\text{ep\_end\_year}_{(z,e)\text{ in EXISTING\_PLANTS}} = \min\left(\text{end\_year}, \left(\text{start\_year} + \left(\text{ceiling}\left(\frac{\text{ep\_vintage}_{z,e} + \text{ep\_max\_age\_years}_{z,e} - \text{start\_year}}{\text{years\_per\_period}}\right) \cdot \text{years\_per\_period}\right)\right)\right)$

SI.6.2. Constraints on operation of existing power plants

Nuclear, coal and cogeneration plants must be run at their peak output level at all times (prorated by their scheduled outage rate, which is used as a proxy for their normal utilization level), unless they are mothballed:

$$\begin{aligned}
&\text{subject to } \left(\text{for } \left\{(z,e,h) \in \text{EP_DISPATCH_HOURS: ep_baseload}_{z,e} = 1\right\}\right):\\
&\quad \text{DispatchEP}_{z,e,h} =\\
&\quad\quad \text{OperateEPDuringYear}_{z,e,\text{period}_h} \cdot \left(1 - \text{ep_forced_outage_rate}_{z,e}\right) \cdot \left(1 - \text{ep_scheduled_outage_rate}_{z,e}\right) \cdot \text{ep_size_mw}_{z,e}
\end{aligned}$$

In the future this constraint may be made less conservative, e.g., requiring baseload plants to run at a constant level for one sample day at a time, or for all sample days that fall in the same season.

An additional constraint ensures that power plants deliver no more power than their nameplate rating. This is further limited by the amount of capacity that is expected to be offline on average:

$$\begin{aligned}
&\text{subject to } \left(\text{for } (z,e,h) \in \text{EP_DISPATCH_HOURS}\right):\\
&\quad \text{DispatchEP}_{z,e,h} \leq\\
&\quad\quad \text{OperateEPDuringYear}_{z,e,\text{period}_h} \cdot \left(1 - \text{ep_forced_outage_rate}_{z,e}\right) \cdot \text{ep_size_mw}_{z,e}
\end{aligned}$$

SI.6.3. Data for California Study

SI.6.3.1. Fossil and Geothermal Power Plants

Data on the size, technology, location, ownership and operational mode of all existing power plants in California were obtained from the Energy Information Administration's power plant survey databases for 2006 (25, 26). The same information was also obtained for several power plants in Arizona, New Mexico and Nevada, that are partially owned by California electric utilities, and capable of delivering power to California. For this study, the power-generating capacity of the out-of-state plants has been prorated according to the share of the plant owned by California utilities; i.e., they are treated as smaller plants that can be operated as needed to serve California electricity loads. In all, the model uses data on 270 existing natural gas, coal, nuclear and geothermal plants, with a combined peak output of 44 GW.

Power plants are categorized based on their fuel and mode of operation. All nuclear, coal and geothermal power plants, as well as gas-fired cogeneration plants, are assumed to operate in a baseload mode, year round, producing as much power as they did on average in 2002–04. The remaining gas-fired power plants are assumed to be dispatchable as needed, and the model chooses each hour whether or not to operate them.

All nuclear, coal and geothermal power plants, as well as gas-fired cogeneration plants, are assumed to be capable only of operating in baseload mode, year round, producing as much power as they did on average in 2002–04. The remaining gas-fired power plants are assumed to be dispatchable as needed.

The efficiency of most existing power plants was calculated by dividing their net power generation in 2002–04 by the amount of fuel that they consumed during the same period. It is assumed that they will operate with the same efficiency any time they are used in the future. However, the EIA surveys do not collect enough data to determine the electrical efficiency of cogeneration facilities. For this study, it is assumed that these plants are 75 percent efficient in converting fuel into steam heat and electricity, and that if necessary, they could instead produce only steam, also at 75 percent efficiency (EPA (27) shows thermal efficiencies of 56–86 percent for typical cogeneration plants). These two assumptions yield a marginal efficiency for production of electricity that is also 75 percent.

Existing natural gas power plants are assumed to have the same operating costs and forced outage rates as new plants of the same type. However, cogeneration plants are assumed to cost three-quarters as much as free-standing power plants, to reflect the sharing of costs with steam infrastructure that would be needed even if no electricity were produced. Costs for coal, nuclear and geothermal plants are based on assumptions to AEO.

Forced outage rates of existing natural gas plants are assumed to be the same as those given for new plants in the CEC's cost of generation study. Other plants are assumed to have a 1 percent forced outage rate.

Retirement ages for existing coal, gas and nuclear plants are estimated by averaging the retirement age of similar plants that have already been retired, as shown in the EIA databa fses (26). No retired geothermal plants are shown in the EIA databases, so binary turbine plants are assumed to have a retirement age of 30 years (5 years longer than natural gas turbines in the EIA database), and geothermal steam turbines are assumed to last 45 years, corresponding to other steam turbine plants.

SI.6.3.2. Wind, Solar and other Generators

Existing wind, solar, and biomass/waste generators are not modeled explicitly in this study. Existing wind farms provided 4.7 percent of California's electricity in 2010. As noted in the main text, the optimal design for the California power system includes significantly more wind power than this in all cases. So if existing wind farms were incorporated explicitly, they would simply reduce new installations by a similar amount, maintaining the same total cost and production of wind power.

Biomass and waste-powered generators supplied 2.4 percent of California's electricity in 2010. If incorporated into the study they would be expected to displace an equal amount of fossil power from the system, resulting in lower total emissions and costs than I have reported.

Solar power generators supplied 0.3% of the state's power in 2010, but the California Solar Initiative, announced in 2006, provides incentives to install enough photovoltaic equipment by 2017 to raise this share to about 1.5 percent (3 GW nameplate). These systems would be expected to displace a similar amount of solar photovoltaic or solar thermal-electric generators from the model results shown here.

SI.7. HYDROELECTRIC POWER AND PUMPED STORAGE

SI.7.1. Modeling of Hydroelectric Plants

Switch is not allowed to build new hydroelectric plants, but it can make intensive use of existing ones. Existing plants are not retired during the study.

Switch uses two constraints to represent water flow limits at hydroelectric dams in a simplified manner: (1) The net flow of water through each hydroelectric dam each day must equal a pre-specified average level, and (2) the flow of water through each hydroelectric dam must equal or exceed a pre-specified minimum level in each hour. These targets may be negative for pumped storage facilities. To simplify integration with the rest of the model, these targets are specified as average and minimum *power* flows that would occur if the appropriate amount of water is released.

Hydro flow constraints are formulated on a daily basis, instead of weekly, monthly or longer scale for several reasons. (1) Limited data are available on the availability of water and storage on a sub-monthly time-scale. Using the same constraints for every day of the month is a conservative approach, which is guaranteed to yield monthly average flows that match historical behavior. (2) In order to model storage and dispatch of water between any two periods, both periods must be included in the Switch model. Since the model is run with randomly sampled days in the optimization phase, it is not possible to model storage of water over periods of longer than one day, e.g., from one week to the next. (3) Many reservoirs have limited storage capacity, so that it may be unrealistic to plan to store more than a day's worth of water in them.

Switch chooses how much power to generate in each hour, from each hydroelectric dam larger than 100 MW, subject to these constraints. To reduce memory requirements and speed up computation, all hydroelectric plants smaller than 100 MW are dispatched on an aggregated basis, using a single diurnal schedule for each combination of load zone, season and study period. This dispatch method works by dividing the hydro flow at each plant into a minimum and discretionary component (equal to the difference between average flow and minimum flow). Then the DispatchShareAggregHydro decision variable specifies what fraction of each day's discretionary flow will be released during each hour. This same schedule may be applied to many different hydro projects simultaneously, on either an individual or aggregated basis.

The power flow from hydroelectric plants is given by

$$\text{HydroOutputEnergy}_{z,h} = \text{DetailedHydroEnergy}_{z,h} + \text{AggregHydroEnergy}_{z,h}$$

where

$$\text{DetailedHydroEnergy}_{z,h} = \left(1 - \text{forced\_outage\_rate\_hydro}\right) \cdot \sum_{\substack{(z,s) \in \\ \text{PROJ\_DETAILED\_HYDRO}}} \text{DispatchDetailedHydro}_{z,s,h}$$

and

$$\begin{aligned}&\text{AggregHydroEnergy}_{z,h} = \\ &\quad \left(1 - \text{forced\_outage\_rate\_hydro}\right) \\ &\quad \cdot \left(\text{min\_hydro\_dispatch\_all\_sites}_{z,\text{date}_h} + \text{DispatchShareAggregHydro}_{\substack{\text{period}_h, \\ z, \\ \text{season\_of\_year}_h, \\ \text{hour\_of\_day}_h}} \cdot \begin{pmatrix} \text{avg\_hydro\_dispatch\_all\_sites}_{z,\text{date}_h} \\ - \text{min\_hydro\_dispatch\_all\_sites}_{z,\text{date}_h} \end{pmatrix} \cdot 24 \right)\end{aligned}$$

Power consumption by hydroelectric pumped storage plants is given by

$$\begin{aligned}&\text{HydroStorageEnergy}_{z,h} = \\ &\quad \left(1 - \text{forced\_outage\_rate\_hydro}\right) \cdot 1/\text{pumped\_hydro\_efficiency} \cdot \sum_{\substack{(z,s) \in \\ \text{PROJ\_PUMPED\_HYDRO}}} \text{StorePumpedHydro}_{z,s,h}\end{aligned}$$

All of the hydro energy flows are de-rated to reflect the typical unavailability of hydroelectric plants. That is, the decision variables (DispatchDetailedHydro and DispatchShareAggregHydro) set the amount of power that would be produced if the plant acted as expected, but the system actually receives a smaller amount of energy, reflecting the average rate of outages at the plant. Unlike other generators, the de-rating for hydro plants occurs after the dispatch schedule is made. This is done so that the dispatch schedules are more directly linked to the flows of water through the plant. The dispatch schedules respect minimum and average power flow constraints given below, which correspond to minimum and average water flow constraints. It is assumed that the corresponding amount of water is released even if the plant is unexpectedly unable to produce electricity at some times.

It should also be noted that the StorePumpedHydro variable indicates the amount of energy that can later be retrieved by releasing water that was stored at a given site in a given hour. The amount of energy required to store that water is greater by a factor of 1/pumped_hydro_efficiency.

Switch makes a separate set of decisions about how it would use the available resources to meet loads in the reserve margin scenario (this scenario requires the model to be able to meet loads 15% higher than expected, assuming there are no forced outages at generating plants):

$$\text{HydroOutputEnergy\_Reserve}_{z,h} = \text{DetailedHydroEnergy\_Reserve}_{z,h} + \text{AggregHydroEnergy\_Reserve}_{z,h}$$

where

$$\text{DetailedHydroEnergy\_Reserve}_{z,h} = \sum_{\substack{(z,s)\in \\ \text{PROJ\_DETAILED\_HYDRO}}} \text{DispatchDetailedHydro\_Reserve}_{z,s,h}$$

and

$$\begin{aligned}&\text{AggregHydroEnergy\_Reserve}_{z,h} = \\ &\quad \text{min\_hydro\_dispatch\_all\_sites}_{z,\text{date}_h} + \text{HydroDispatchShare\_Reserve}_{\substack{\text{period}_h, \\ z, \\ \text{season\_of\_year}_h, \\ \text{hour\_of\_day}_h}} \cdot \begin{pmatrix} \text{avg\_hydro\_dispatch\_all\_sites}_{z,\text{date}_h} \\ -\ \text{min\_hydro\_dispatch\_all\_sites}_{z,\text{date}_h} \end{pmatrix} \cdot 24\end{aligned}$$

Power consumption by hydroelectric pumped storage plants in the reserve scenario is given by

$$\begin{aligned}&\text{HydroStorageEnergy\_Reserve}_{z,h} = \\ &\quad 1/\text{pumped\_hydro\_efficiency} \cdot \sum_{\substack{(z,s)\in \\ \text{PROJ\_PUMPED\_HYDRO}}} \text{StorePumpedHydro\_Reserve}_{z,s,h}\end{aligned}$$

The cost of the hydroelectric system is calculated on a simplified basis. The capital and O&M costs for hydroelectric plants are bundled into a single annual cost per MW of capacity (hydro_annual_payment_per_mw), which is applied to all hydroelectric projects. This gives the following equation for the cost of hydroelectric plants:

$$\begin{aligned}\text{HydroCostPerHour} &= \text{hydro\_cost\_per\_mw\_per\_hour} \cdot \text{hydro\_total\_capacity} \\ &= \text{hydro\_annual\_payment\_per\_mw} / \text{hours\_per\_year} \cdot \text{hydro\_total\_capacity}\end{aligned}$$

Tables SI.16–SI.18 give more details on the indexing sets, decision variables and input parameters used to model hydroelectric plants. These are followed by additional constraints that affect hydroelectric operation, and then a summary of the data used to model the California hydroelectric system for this case study.

Table SI.16. Sets used to define hydroelectric projects

Name	Indexing variables	Description	Definition
PROJ_HYDRO	(*z*,*s*)	Existing hydroelectric plants (identified by load zone (*z*) and site ID (*s*))	PROJ_HYDRO = setof {(z, s, d) in PROJ_HYDRO_DATES} (z, s)
PROJ_DETAILED_HYDRO	(*z*,*s*)	Hydroelectric plants that should be dispatched individually on an hourly basis.	PROJ_DETAILED_HYDRO = setof {(z, s, d) in PROJ_HYDRO_DATES: min_hydro_flow[z, s, d] < 0 or z="Northwest" or max_hydro_flow[z, s, d] >= 100} (z, s)
PROJ_AGGREG_HYDRO	(*z*,*s*)	Hydroelectric plants that will be dispatched on an aggregated, zonal basis.	PROJ_AGGREG_HYDRO = PROJ_HYDRO \ PROJ_DETAILED_HYDRO
PROJ_HYDRO_DATES	(*z*,*s*,*d*)	Dates when hydroelectric plants can be run.	Specified exogenously (read in with avg_hydro_flow, max_hydro_flow and min_hydro_flow)
HOURS_OF_DAY		Hours of the day that are included in the model (may not include all 24 hours).	{for h ∈ HOURS: hour_of_day_h}
SEASONS_OF_YEAR		Seasons of the year that are included in the model.	{for h ∈ HOURS: season_of_year_h}

Table SI.17. Decision variables for hydroelectric projects

Name	Indexing set	Description
DispatchDetailedHydro	PROJ_HYDRO × HOURS	Number of MW of power to generate at each hydroelectric project during each hour
DispatchDetailedHydro_Reserve	PROJ_HYDRO × HOURS	Identical to DispatchDetailedHydro, but used to schedule hydro under the reserve margin scenario instead of normal conditions.
StorePumpedHydro	TRANS_LINES × HOURS	Number of MW of power to store at each pumped hydro project during each hour
StorePumpedHydro_Reserve	TRANS_LINES × HOURS	Identical to StorePumpedHydro, but used to schedule storage under the reserve margin scenario instead of normal conditions.
DispatchShareAggregHydro	PERIODS × LOAD_ZONES × SEASONS_OF_YEAR × HOURS_OF_DAY	Fraction of daily total discretionary hydro flow (average flow minus minimum flow) to dispatch during each hour. Used to dispatch projects in PROJ_AGGREG_HYDRO on an aggregated basis. One diurnal schedule is set for each period, load zone and season.
DispatchShareAggregHydro_Reserve	PERIODS × LOAD_ZONES × SEASONS_OF_YEAR × HOURS_OF_DAY	Identical to DispatchShareAggregHydro, but used to set the hydro schedule under the reserve margin scenario instead of normal conditions.

Table SI.18. Parameters for hydroelectric projects

Name	Indexed over	Description	Definition
avg_aggreg_ hydro_dispatch_ all_sites	LOAD_ZONES × DATES	Average total flow from all hydro facilities using aggregated dispatch in load zone *z* on date *d*.	$\text{avg\_aggreg\_hydro\_dispatch\_all\_sites}_{z,d} = \sum_{(z,\,s)\,\in\,\text{PROJ\_AGGREG\_HYDRO}} \text{avg\_hydro\_flow}_{z,s,d}$
avg_hydro_flow	PROJ_ HYDRO_ DATES	Average power flow required at each hydroelectric project each day.	Specified exogenously.
forced_outage_ rate_hydro	(single value)	Forced outage rate for hydroelectric dams	Specified exogenously (value of 0.02 used for California study).
hydro_annual_ payment_per_ mw	(single value)	Carrying cost for existing hydroelectric facilities in 2012$ per year per MW of capacity.	Specified exogenously (see text below).
hydro_cost_per_ mw_per_hour	(single value)	Carrying cost for existing hydroelectric facilities, apportioned on an hourly basis	hydro_cost_per_mw_per_hour = hydro_annual_payment_per_mw / hours_per_year
hydro_total_ capacity		Total amount of existing hydroelectric capacity (in MW)	hydro_total_capacity = sum {(z, s) in PROJ_HYDRO} (max {(z, s, d) in PROJ_HYDRO_DATES} max_hydro_flow[z, s, d])
max_aggreg_ hydro_dispatch_ per_ hour	(single value)	Maximum share of each day's "discretionary" hydro flow (the difference between minimum_ hydro_flow and average_hydro_ flow) that can be dispatched in a single hour. Higher values produce narrower, taller hydro dispatch schedules, but also more "baseload" hydro.	Specified exogenously (value of 0.167 used for California study).
max_hydro_flow	PROJ_ HYDRO_ DATES	Maximum power flow allowed at each hydroelectric project each day (generally equal to the rated capacity of the plant).	Specified exogenously.
min_aggreg_ hydro_dispatch	PROJ_ AGGREG_ HYDRO × DATES	Minimum flow rate for each hydro facility using aggregated dispatch. If necessary this is raised above the plant's min_ hydro_flow constraint, to ensure that the flow from each plant never exceeds max_ hydro_flow, even when DispatchShareAggregHydro is at its upper limit (max_aggreg_hydro_ dispatch_per_ hour).	$\text{min\_aggreg\_hydro\_dispatch}_{z,s,d} = \max\left(\frac{\left(\text{max\_aggreg\_hydro\_dispatch\_per\_hour}\cdot 24\cdot \text{avg\_hydro\_flow}_{z,s,d} - \text{max\_hydro\_flow}_{z,s,d}\right)}{\text{max\_aggreg\_hydro\_dispatch\_per\_hour}\cdot 24 - 1},\ \text{min\_hydro\_flow}_{z,s,d}\right)$
min_aggreg_ hydro_dispatch_ all_sites	LOAD_ZONES × DATES	Minimum total flow from all hydro facilities using aggregated dispatch in load zone *z* on date *d*.	$\text{min\_aggreg\_hydro\_dispatch\_all\_sites}_{z,d} = \sum_{(z,\,s)\,\in\,\text{PROJ\_AGGREG\_HYDRO}} \text{min\_aggreg\_hydro\_dispatch}_{z,s,d}$
min_hydro_flow	PROJ_ HYDRO_ DATES	Minimum power flow required at each hydroelectric project each day.	Specified exogenously.
pumped_hydro_ efficiency	(single value)	Round-trip efficiency for storing power via a pumped hydro system	Specified exogenously (value of 0.7 used for California study {Hawkins, 2008 #366}).
hour_of_day	HOURS	Hour of day represented by each sample hour (e.g., the hour starting at 4 p.m.)	Specified exogenously.

season_of_year	HOURS	Season of the year represented by each sample hour (e.g., 1 for winter)	Specified exogenously.

SI.7.2. Constraints on hydroelectric operation

Dispatch of individual hydro plants must be below the plants' upper limits at all times (in both the standard load-serving scenario and the reserve-margin scenario):

$$\begin{aligned}&\text{subject to } \left(\text{for } (z,s) \text{ in PROJ\_DETAILED\_HYDRO, h in HOURS}\right):\\&\quad \text{DispatchDetailedHydro}_{z,s,h} \leq \text{max\_hydro\_flow}_{z,s,date_h}\\&\quad \text{DispatchDetailedHydro\_Reserve}_{z,s,h} \leq \text{max\_hydro\_flow}_{z,s,date_h}\end{aligned}$$

Pumped hydro storage must also respect limits on the pumping flow rate:

$$\begin{aligned}&\text{subject to } \left(\text{for } (z,s) \in \text{PROJ\_DETAILED\_HYDRO, h} \in \text{HOURS: min\_hydro\_flow}_{z,s,date_h} < 0\right):\\&\quad \text{StorePumpedHydro}_{z,s,h} \leq -\text{min\_hydro\_flow}_{z,s,date_h}\\&\quad \text{StorePumpedHydro\_Reserve}_{z,s,h} \leq -\text{min\_hydro\_flow}_{z,s,date_h}\end{aligned}$$

Net flow of power (i.e., water) cannot exceed the historical average (it can fall below, which corresponds to spilling water without generating power):

$$\begin{aligned}&\text{subject to } \left(\text{for } (z,s) \text{ in PROJ\_DETAILED\_HYDRO, d in DATES}\right):\\&\sum_{\substack{\text{h in HOURS:}\\ date_h = d}} \left(\text{DispatchDetailedHydro}_{z,s,h} - \text{StorePumpedHydro}_{z,s,h}\right) \cdot \text{hours\_in\_sample}_h\\&\quad \leq \sum_{\substack{\text{h in HOURS:}\\ date_h = d}} \text{avg\_hydro\_flow}_{z,s,d} \cdot \text{hours\_in\_sample}_h\\&\sum_{\substack{\text{h in HOURS:}\\ date_h = d}} \left(\text{DispatchDetailedHydro\_Reserve}_{z,s,h} - \text{StorePumpedHydro\_Reserve}_{z,s,h}\right) \cdot \text{hours\_in\_sample}_h\\&\quad \leq \sum_{\substack{\text{h in HOURS:}\\ date_h = d}} \text{avg\_hydro\_flow}_{z,s,d} \cdot \text{hours\_in\_sample}_h\end{aligned}$$

Hydro projects without pumped storage capabilities (i.e., projects with minimum flows of zero or more) must respect minimum flow constraints and cannot store energy:

$$\begin{aligned}&\text{subject to } \left(\text{for } (z,s) \text{ in PROJ\_DETAILED\_HYDRO, h in HOURS: min\_hydro\_flow}_{z,s,date_h} \geq 0\right):\\&\quad \text{DispatchDetailedHydro}_{z,s,h} \geq \text{min\_hydro\_flow}_{z,s,date_h}\\&\quad \text{StorePumpedHydro}_{z,s,h} = 0\\&\quad \text{DispatchDetailedHydro\_Reserve}_{z,s,h} \geq \text{min\_hydro\_flow}_{z,s,date_h}\\&\quad \text{StorePumpedHydro\_Reserve}_{z,s,h} = 0\end{aligned}$$

The total flow each day cannot exceed 100% of the flow available.

$$\text{subject to } (\text{for } p \in \text{PERIODS}, z \in \text{LOAD\_ZONES}, s \in \text{SEASONS\_OF\_YEAR}):$$

$$\sum_{h \in \text{HOURS\_OF\_DAY}} \text{DispatchShareAggregHydro}_{p,z,s,h} \cdot \frac{24}{n_{\text{HOURS\_OF\_DAY}}} \leq 1$$

$$\sum_{h \in \text{HOURS\_OF\_DAY}} \text{DispatchShareAggregHydro\_Reserve}_{p,z,s,h} \cdot \frac{24}{n_{\text{HOURS\_OF\_DAY}}} \leq 1$$

For aggregated hydro, a model-wide input parameter (max_aggreg_hydro_dispatch_per_hour) restricts the amount of each day's discretionary flow that can be concentrated in any single hour. Each hour's dispatch must also be non-negative.

$$\text{subject to } (\text{for } p \in \text{PERIODS}, z \in \text{LOAD\_ZONES}, s \in \text{SEASONS\_OF\_YEAR}, h \in \text{HOURS\_OF\_DAY}):$$

$$0 \leq \text{DispatchShareAggregHydro}_{p,z,s,h} \leq \text{max\_aggreg\_hydro\_dispatch\_per\_hour}$$

$$0 \leq \text{DispatchShareAggregHydro\_Reserve}_{p,z,s,h} \leq \text{max\_aggreg\_hydro\_dispatch\_per\_hour}$$

SI.7.3. Hydroelectric data used for California case study

Hydroelectric plant sizes, locations and historical water flows are derived from databases published by the Energy Information Administration and the United States Geological Survey (25, 26, 28). An additional "virtual" hydroelectric plant is added in the Northwest load zone, to represent hydroelectric power available for import to California from the Northwest. The monthly flow data for this plant are based on historical power transfers, as reported by the Northwest Power Pool (29).

The average hydro flow target (avg_hydro_flow) for each dam for each date of the simulation is set equal to the average production during the historical month corresponding to that date (e.g., on a simulated date in 2020, which uses weather conditions from March 20, 2004, each dam must release 1/31 as much water as it did during the month of March 2004). The minimum hydro flow (min_hydro_flow) is equal to 10 percent of the required average flow rate for that day.

Plants smaller than 50 MW are forced to operate in baseload mode by setting the minimum and maximum flow rates equal to the average rate. This prevents Switch from overestimating the flexibility available from these small facilities.

The model uses detailed dispatch for 39 hydroelectric plants, with a total nameplate capacity of 20.5 GW and a total average power production of 4.6 GW. Aggregated dispatch is used for 200 smaller plants, with a collective average power output of 1.5 GW. Of these, 177 plants with an average total output of 0.7 GW are run in baseload mode.

The carrying cost for hydro and pumped hydro facilities (hydro_annual_payment_per_mw) is calculated assuming a \$1500/kW capital cost, \$13/kW·year fixed O&M, \$3.30/MWh variable O&M, 30% capacity factor (typical for California hydro projects), 6% real finance rate and 70-year project life. This results in an annual cost of \$113,172 per kW of capacity (equivalent to about \$43/MWh).

SI.8. LONG-DISTANCE (INTER-ZONAL) TRANSMISSION

SI.8.1. Representation of the transmission network in Switch

Power system operators and analysts usually use security-constrained optimal power flow (SCOPF) models to decide which generators should be operated each hour, in order to provide power to all loads at the lowest cost without overloading any transmission lines. These tools directly model the electrical properties of each substation and transmission line in the network, and are ideal for studying how to *operate* the power system. However they would become computationally intractable if extended to consider how best to *expand* the generation and transmission capacity of the power system.

Rather than model the electrical properties of the transmission network directly, Switch uses a more compact "transport model" to represent the *capabilities* of the transmission network and the cost of upgrading those capabilities. As noted above, Switch divides the study region into a number of load zones. Transmission corridors are defined between these load zones, and the model chooses how much transfer capability (5-7) to add along each corridor during each investment period and how much power to send along each corridor each hour. (This is called a "transport model" because it is analogous to the flow of cars or goods on a road network. In contrast, an SCOPF model would choose voltages and current injections at each node and then calculate the induced power flow along each line).

Although a transport model is a dramatic simplification of the power system, it can at least provide useful hints about the areas where transmission upgrades will be needed. Romero and Monticelli (9) note that transport models generally identify 60–70 percent of the transmission investments that would be identified using a full network model. As sophisticated electronics allow for more direct control of power flows on some transmission paths, the power system itself may also come to resemble a transport network to a greater degree (8). However, this simplified representation of the transport network remains a weakness of the current version of Switch, and a full network model will be incorporated into the post-optimization assessment phase in the future.

The cost of new and existing transmission is incorporated into Switch's objective function via NewTransCapitalCostPerHour and ExistingTransCapitalCostPerHour. These include only the capital repayment needed for new or existing transmission lines:

$$\text{NewTransCapitalCostPerHour}_{z,h} = \sum_{\substack{(z1,z2)\in \text{TRANS\_LINES},\\ v\in \text{VINTAGE\_YEARS}:\, v\le p}} \text{InstallTrans}_{z1,z2}\cdot \text{transmission\_cost\_per\_mw\_per\_hour}_{z1,z2,v}$$

$$\text{ExistingTransCapitalCostPerHour}_{z,h} = \sum_{(z1,z2)\in \text{TRANS\_LINES}} \text{transmission\_cost\_per\_existing\_mw\_per\_hour}_{z1,z2}\cdot \frac{\left(\begin{array}{l}\text{existing\_transmission\_from}_{z1,z2}\\ +\ \text{existing\_transmission\_to}_{z1,z2}\end{array}\right)}{2}$$

Net transfers of power into each zone are included in the load-serving constraint via $\text{NetImports}_{z,h}$ and $\text{NetImports\_Reserve}_{z,h}$. Separate operating decisions are made for normal operation and for the reserve-margin scenario:

$$\begin{aligned}\text{NetImports}_{z,h} = &\sum_{(z,z2)\in \text{TRANS\_LINES}} \text{transmission\_efficiency}_{z,z2}\cdot \text{DispatchTransTo}_{z,z2,h} - \text{DispatchTransFrom}_{z,z2,h}\\ &- \sum_{(z1,z)\in \text{TRANS\_LINES}} \text{DispatchTransTo}_{z1,z,h} - \text{transmission\_efficiency}_{z1,z}\cdot \text{DispatchTransFrom}_{z1,z,h}\end{aligned}$$

$$\begin{aligned}\text{NetImports\_Reserve}_{z,h} = &\sum_{(z,z2)\in \text{TRANS\_LINES}} \text{transmission\_efficiency}_{z,z2}\cdot \text{DispatchTransTo\_Reserve}_{z,z2,h} - \text{DispatchTransFrom\_Reserve}_{z,z2,h}\\ &- \sum_{(z1,z)\in \text{TRANS\_LINES}} \text{DispatchTransTo\_Reserve}_{z1,z,h} - \text{transmission\_efficiency}_{z1,z}\cdot \text{DispatchTransFrom\_Reserve}_{z1,z,h}\end{aligned}$$

Note that the convention for transmission losses is that $\text{DispatchTransFrom}_{z1,z2}$ shows how much power goes from load zone z1 into the z1→z2 transmission corridor, and $\text{transmission\_efficiency}_{z1,z2} \cdot \text{DispatchTransFrom}_{z1,z2}$ shows how much power reaches load zone z2 from this corridor, net of losses.

The sets, variables and parameters used to describe the transmission system are summarized in Tables SI.19–SI.21.

Table SI.19. Sets used to define inter-zonal transmission

Name	Indexing variables	Description	Definition
TRANS_LINES	(*z1*,*z2*)	Transmission corridors that already exist or could be built; these connect load zone *z1* to load zone *z2* (note: there are no duplicate members; if (*a*,*b*) is in this set, then (*b*,*a*) is not)	Specified exogenously.
TRANS_VINTAGE_HOURS	(*z1*,*z2*,*v*,*h*)	Valid combinations of transmission corridor, vintage and operational hour (h) (for which dispatch decisions must be made).	$\{(z1, z2) \in \text{TRANS\_LINES}, v \in \text{VINTAGE\_YEARS}, h \in \text{HOURS}: v \leq \text{period}_h < \text{transmission\_end\_year}_v\}$

Table SI.20. Decision variables for inter-zonal transmission

Name	Indexing set	Description
InstallTrans	TRANS_LINES × VINTAGE_YEARS	Number of MW of new capacity to install along each transmission corridor at the start of each investment period
DispatchTransTo	TRANS_LINES × HOURS	Number of MW of power to send to zone z1 from zone z2 during each hour
DispatchTransFrom	TRANS_LINES × HOURS	Number of MW of power to send from zone z1 to zone z2 during each hour
DispatchTransTo_Reserve	TRANS_LINES × HOURS	Number of MW of power to send to zone z1 from zone z2 during each hour
DispatchTransFrom_Reserve	TRANS_LINES × HOURS	Number of MW of power to send from zone z1 to zone z2 during each hour

Table SI.21. Parameters used to define inter-zonal transmission

Name	Indexed over	Description	Definition
existing_transmission_from	TRANS_LINES	Limit for power flows from zone z1 to zone z2 along existing transmission lines.	Specified exogenously.
existing_transmission_to	TRANS_LINES	Limit for power flows to zone z1 from zone z2 along existing transmission lines.	Specified exogenously.
transmission_cost_per_existing_mw_per_hour	TRANS_LINES × VINTAGE_YEARS	Identical to transmission_cost_per_mw_per_hour but applied only to existing transmission lines.	$\text{transmission\_cost\_per\_existing\_mw\_per\_hour}_{z1,z2} = \text{transmission\_cost\_per\_existing\_mw\_km} \cdot \frac{\text{transmission\_cost\_per\_mw\_per\_hour}_{z1,z2,\text{start\_year}}}{\text{transmission\_cost\_per\_mw\_km}}$
transmission_cost_per_existing_mw_km	(single value)	Sunk capital cost for existing transmission lines.	Specified exogenously.
transmission_cost_per_mw_per_hour	TRANS_LINES × VINTAGE_YEARS	The cost per MW to install additional transfer capability between zones z1 and z2 in year v. This is amortized as an hourly payment over the life of the upgrade.	$\text{transmission\_cost\_per\_mw\_per\_hour}_{z1,z2,v} = \text{transmission\_cost\_per\_mw\_per\_year}_{z1,z2,v} / \text{hours\_per\_year}$
transmission_cost_per_mw_km	(single value)	Cost to build a transmission line, per mw of capacity, per km of distance.	Specified exogenously.
transmission_cost_per_mw_per_year	TRANS_LINES × VINTAGE_YEARS	The annual repayment required for capital investment in new transmission capacity, per MW of capacity, expressed as an annual cost during the life of upgrade.	$\text{transmission\_cost\_per\_mw\_per\_year}_{z1,z2,v} = \text{transmission\_cost\_per\_mw\_km} \cdot \text{transmission\_length\_km}_{z1,z2} \cdot \frac{\text{transmission\_finance\_rate}}{1-\left(1+\text{transmission\_finance\_rate}\right)^{-\text{transmission\_max\_age\_years}}}$
transmission_efficiency	TRANS_LINES	Efficiency of delivering electricity along each transmission corridor.	Specified exogenously.
transmission_end_year	VINTAGE_YEARS	First year when transmission capacity built in year *v* will be unavailable due to retirement. (Transmission capacity is assumed to be available until the end of the study period in which it is retired.)	$\text{transmission\_end\_year}_v = \min\left(\text{end\_year}, v + \text{ceiling}\left(\frac{\text{transmission\_max\_age\_years}}{\text{years\_per\_period}}\right) \cdot \text{years\_per\_period}\right)$
transmission_finance_rate	(single value)	Finance rate used to amortize capital costs over the life of transmission projects.	Specified exogenously.
transmission_forced_outage_rate	(single value)	Forced outage rate for transmission lines.	Specified exogenously.
transmission_length_km	TRANS_LINES	Length of each transmission corridor.	Specified exogenously.
transmission_max_age_years	(single value)	Retirement age for transmission lines.	Specified exogenously.

SI.8.2. Constraints on the Inter-Zonal Transmission System

The amount of power that can be sent along each transmission corridor is limited by the amount of transfer capability that already exists, plus any added by the model. For the main cost optimization, transfer capability along each corridor is prorated by its forced outage rate to reflect the typical level of unavailability. For the reserve-margin scenario, the full transfer capability is available, since the reserve margin is designed to cover any potential outages.

Note that for a transmission corridor between zones *z1* and *z2*, the model choose both how much power to transmit *from z1* to *z2* ($\text{DispatchTransFrom}_{z1,z2}$) and how much to send *to z1* from *z2* ($\text{DispatchTransTo}_{z1,z2}$). These are both non-negative values.

$$\text{subject to } \left(\text{for } (\text{z1,z2}) \in \text{TRANS\_LINES},\ \text{h} \in \text{HOURS}\right):$$

$$\text{DispatchTransTo}_{\text{z1,z2,h}} \leq \left(1 - \text{transmission\_forced\_outage\_rate}\right) \cdot \left(\begin{array}{l} \text{existing\_transmission\_to}_{\text{z1,z2}} \\ + \displaystyle\sum_{\substack{(\text{z1,z2,v,h})\in \\ \text{TRANS\_VINTAGE\_HOURS}}} \text{InstallTrans}_{\text{z1,z2,v}} \end{array}\right),$$

$$\text{DispatchTransFrom}_{\text{z1,z2,h}} \leq \left(1 - \text{transmission\_forced\_outage\_rate}\right) \cdot \left(\begin{array}{l} \text{existing\_transmission\_from}_{\text{z1,z2}} \\ + \displaystyle\sum_{\substack{(\text{z1,z2,v,h})\in \\ \text{TRANS\_VINTAGE\_HOURS}}} \text{InstallTrans}_{\text{z1,z2,v}} \end{array}\right),$$

$$\text{DispatchTransTo\_Reserve}_{\text{z1,z2,h}} \leq \left(\begin{array}{l} \text{existing\_transmission\_to}_{\text{z1,z2}} \\ + \displaystyle\sum_{\substack{(\text{z1,z2,v,h})\in \\ \text{TRANS\_VINTAGE\_HOURS}}} \text{InstallTrans}_{\text{z1,z2,v}} \end{array}\right),$$

$$\text{DispatchTransFrom\_Reserve}_{\text{z1,z2,h}} \leq \left(\begin{array}{l} \text{existing\_transmission\_from}_{\text{z1,z2}} \\ + \displaystyle\sum_{\substack{(\text{z1,z2,v,h})\in \\ \text{TRANS\_VINTAGE\_HOURS}}} \text{InstallTrans}_{\text{z1,z2,v}} \end{array}\right)$$

SI.8.3. California Inter-Zonal Transmission Data

For the California case study, Switch can expand transfer capability along corridors where transmission lines already exist, or build new transmission along any other corridor that is shorter than 300 km. These corridors are shown as black lines in Figure SI.4; routes with existing transmission capacity are highlighted in green. Routes longer than 300 km are excluded to prevent the unrealistic addition of small-capacity, long-distance transmission lines between non-adjacent load zones.

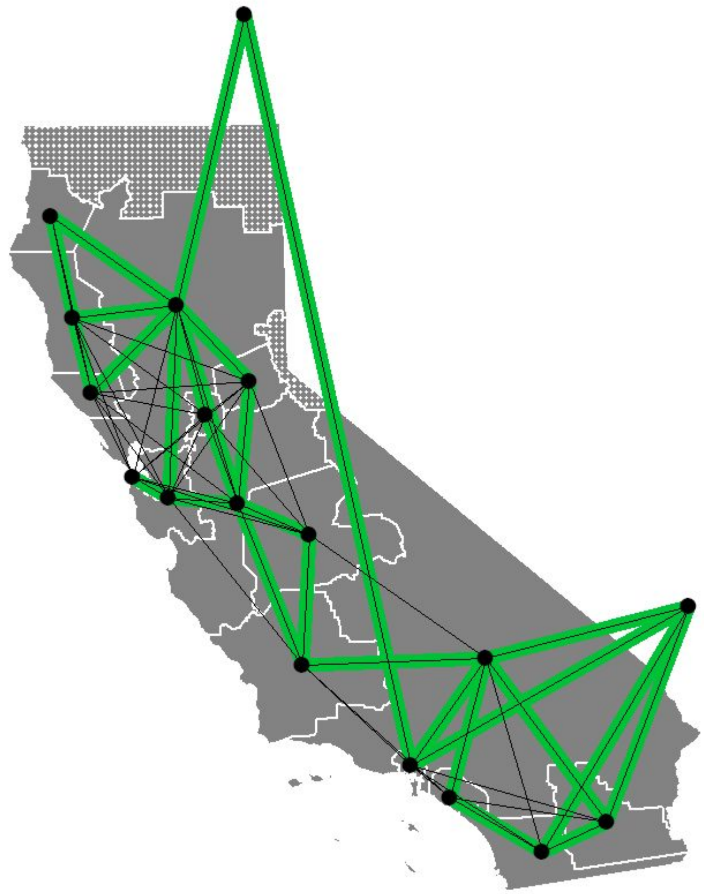

Figure SI.4. Existing (green) and potential (black) transmission routes in California

The cost of transmission upgrades along each corridor is assumed to be $1000 per MW of capacity per km of distance. This is halfway between the cost of building a new single-circuit 230kV line or adding a circuit to an existing 230kV corridor {Fuldner, 1996 #58}, scaled by a factor of 1/0.62 to reflect the ratio between individual line ratings and transfer capability along existing California transmission corridors.{WECC, 2007 #56} This scaling ratio is similar to the 1/0.6 – 1/0.7 ratio reported by Romero and Monticelli (9).

The existing transfer capability between each pair of load zones is calculated as the sum of the “capacity” of all high-voltage transmission lines connecting those load zones. For this purpose, the “capacity” of each line is defined as the lesser of its thermal limit (as reported in WECC’s 2007 form 715 filing (38)), or its transfer limit as reported in the 2007 WECC path rating catalog (38). In cases where a single WECC path is composed of multiple transmission lines, I allocate the combined rating among the individual lines, proportional to their thermal limits. For paths with different limits in each direction, I assign corresponding directional limits to the individual lines that make up the path.

Ratings in the WECC path rating catalog reflect the maximum power that can be transferred along each path, without overloading other lines or creating instability if there is a sudden outage of a power line or plant anywhere in the system. These ratings are calculated by WECC and transmission owners, using full power flow models under a variety of operating conditions. Although Switch does not endogenously model these non-linear constraints on the power system, it does respect all the ones that have been included in the path rating catalog.

Each transmission path is assumed to be 95 percent efficient at delivering power. This is broadly consistent with the losses reported for existing lines in the WECC FERC 715 filing (38). I assume that the voltage and conductor diameter of new lines are chosen to keep losses at this level or less, and that economies of scale for longer transmission lines keep their costs per kilometer the same as shorter lines, while maintaining the same level of losses.

SI.9. LOCAL (INTRA-ZONAL) TRANSMISSION AND DISTRIBUTION

SI.9.1. Modeling of Intra-Zonal Transmission and Distribution

All power from generators and transmission lines is assumed to be delivered to the electrical backbone in each load zone. Switch must also build local transmission and distribution (T&D) capacity to move power intrazonally from the backbone to loads. Enough intrazonal T&D capacity must be built to serve the peak load (net of distributed PV production), and a cost is incurred for each MW of this capacity.

The cost of delivering power within each load zone, from the transmission hub to distributed loads, is parameterized by a single cost for “local T&D capacity.” The model is required to build enough of this generic capacity within each load zone to satisfy the peak load during each investment period. There is then a fixed annual charge to maintain this capacity during each year from that time forward. This is similar to the idea of a demand charge for large electricity customers, to cover the cost of transmission and generation infrastructure to meet their peak load.

Local T&D capacity appears in the Switch cost function via LocalTDCostPerHour, defined as

$$\text{LocalTDCostPerHour}_{z,h} = \sum_{\substack{z \in \text{LOAD\_ZONES}, \\ v \in \text{VINTAGE\_YEARS}:\, v \le \text{period}_h}} \text{InstallLocalTD}_{z,v} \cdot \text{local\_td\_cost\_per\_mw\_per\_hour}_v$$

The local (intra-zone) transmission and distribution capacity in each zone must equal or exceed the electricity demand in that zone during all hours, after subtracting the output from distributed photovoltaic systems:

$$\text{subject to } \left(\text{for z in LOAD\_ZONES, h in HOURS}\right):$$

$$\text{system\_load\_fixed}_{z,h} + \text{DispatchSystemLoad}_{z,h} - \sum_{\substack{(z,t,s,o,v,h) \in \\ \text{PROJ\_INTERMITTENT\_VINTAGE\_HOURS:} \\ t=\text{"DistPV"}}} \left(\begin{array}{l} \left(1 - \text{forced\_outage\_rate}_t\right) \\ \cdot \text{ cap\_factor}_{z,t,s,o,h} \cdot \text{InstallGen}_{z,t,s,o,v} \end{array} \right)$$

$$\le \sum_{\substack{(z,v,h) \in \\ \text{LOCAL\_TD\_HOURS}}} \text{InstallLocalTD}_{z,v}$$

The sets and parameters used in these equations are summarized in Tables SI.22–SI.24.

Table SI.22. Sets used to define intra-zonal transmission

Name	Indexing variables	Description	Definition
TRANS_VINTAGE_HOURS	(*z,v,h*)	Valid combinations of transmission corridor, vintage and operational hour (h) (for which dispatch decisions must be made).	{z ∈ LOAD_ZONES, v ∈ VINTAGE_YEARS, h ∈ HOURS: v <= period_h < $\text{local\_td\_end\_year}_v$}

Table SI.23. Decision variables for intra-zonal transmission

Name	Indexing set	Description
InstallLocalTD	LOAD_ZONES × VINTAGE_YEARS	Number of MW of new intra-zonal transmission and distribution capacity to install in each load zone at the start of each investment period

Table SI.24. Parameters used to define intra-zonal transmission

Name	Indexed over	Description	Definition
local_td_cost_per_mw_per_hour	VINTAGE_YEARS	The cost of building or upgrading intra-zonal transmission and distribution capacity to serve peak zonal loads	$\text{local\_td\_cost\_per\_mw\_per\_hour}_v = \text{local\_td\_annual\_payment\_per\_mw} / \text{hours\_per\_year}$
local_td_max_age_years	(single value)	Retirement age for new intrazonal transmission and distribution capacity.	Specified exogenously.
local_td_annual_payment_per_mw	(single value)	Annual carrying cost for intrazonal transmission and distribution capacity (e.g., annual payment on capital cost)	Specified exogenously.
local_td_end_year	VINTAGE_YEARS	First year when transmission capacity built in year *v* will be unavailable due to retirement.	$\text{local\_td\_end\_year}_v = \min\left(\begin{array}{l}\text{end\_year},\\ v + \text{ceiling}\left(\dfrac{\text{local\_td\_max\_age\_years}}{\text{years\_per\_period}}\right)\cdot\text{years\_per\_period}\end{array}\right)$

SI.9.2. Cost of Intra-Zonal Transmission and Distribution Capacity for California Study

For the work reported here, I use a cost of \$100/kW/year for local transmission and distribution capacity. Little information is available on the cost of providing this service, but this value is in the range suggested by several sources:

(1) E3 (39) estimate avoided transmission and distribution costs of \$20–\$80/kW-year (2004\$) for energy efficiency investments in various California climate zones.

(2) Ofgem (UK) (40) reports that distribution costs make up 25–30 percent of British power bills. If they make up a similar proportion of California power bills, and California has a load factor of 0.6 and average power costs of \$0.12/kWh, then this would mean that a customer with a 1 kW peak load would incur 0.6 kWa/kWp x 8760 hours/year x \$0.12/kWah * 0.25 = \$160/kWp/year in distribution costs.

(3) The Modesto Irrigation District assess a demand charge of \$8.80/kW/month to large customers (41). That charge would equate to \$106/kW/year, if all customers' loads were coincident, and every month had the same peak load. The Modesto Irrigation District is approximately the same size as the load zones in the Switch model, and it may be fair to assume that they set this charge

at a level roughly equal to their costs for delivering power from the high-voltage grid to their customers.

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