MODELING APPROACH DESCRIPTION for EPC-19-060

(Deliverable for Subtask 2.2)

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Executive Summary

This Modeling Approach Description gives a partial summary of the modeling approach. The modeling approach will be refined as the modeling advances.

The main goal is to understand the roles and cost targets of long-duration storage technologies in supporting achievement of California's zero-emission targets. However, the storage technologies are currently not well defined because they are under development, so will mostly be studied through scenarios. This baseline definition largely neglects inclusion of the aspirational storage technologies that we envision. A range of possible storage technology options will be studied in detail as part of the major exploration.

The modeling approach includes use of two capacity-expansion models, RESOLVE and SWITCH 2.0, along with other modeling tools. These will be used with variable input weather data and using variable choices for time steps in order to maximize productivity by shortening the computational time while optimizing the accuracy.

The comparison of the two models will be especially useful because of the inclusion of all of WECC in the SWITCH data base. However, this inclusion complicates the comparison, which will be documented in a later deliverable.

More details are provided in the companion Baseline Description, which focuses on the data inputs; some details are presented in both.

1. Introduction

Modeling grid operation to fully understand the potential value of long-duration storage is challenged because of the complexity of the calculation and the very complicated interactions between the many inputs. To inform our modeling approach we will use simplified calculations such as that shown in Fig. 1.1. This calculation used CAISO 2019 data to estimate how the grid may evolve in the future by removing the thermal and nuclear generation (and the imports) and replacing that generation by scaling up the solar generation to exceed the load by variable amounts. The difference in generation and load on a 5-min basis is used to charge a hypothetical central storage reservoir neglecting transmission considerations and making no effort to quantify costs. The state-of-charge of that reservoir is shown in Fig. 1.1 for one set of input assumptions. The minimum state-of-charge is seen to shift from sometime in March when the annual solar generation is scaled to meet 80% of the annual load to sometime in January when the solar generation is scaled to provide 125% of the annual load.

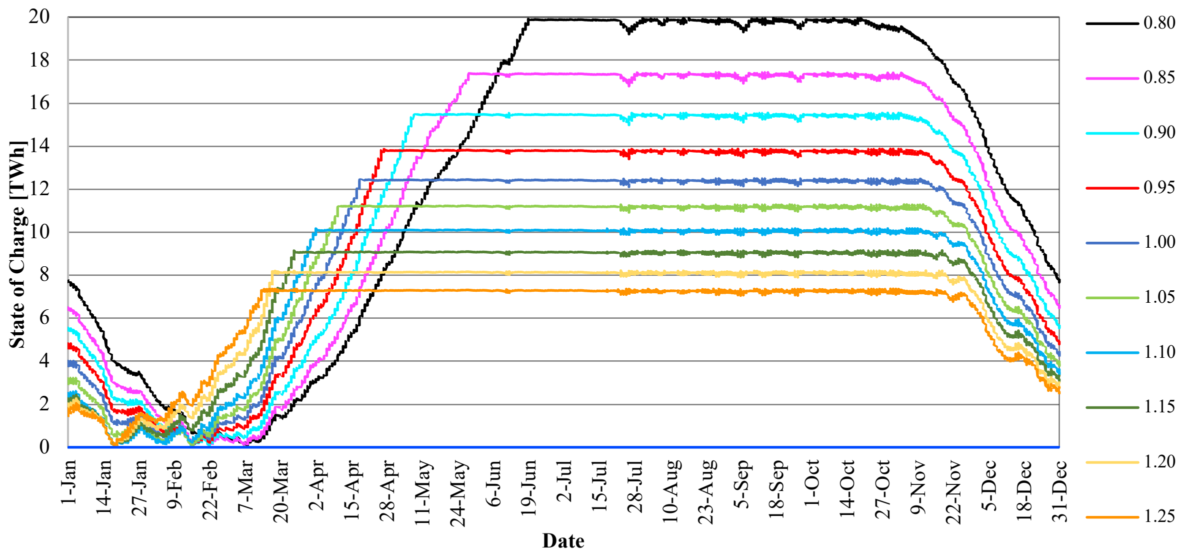

Fig. 1. 1. Calculated stored energy using 2019 data adjusted to reflect zero-carbon grid scenarios with a range of annual solar-generation-to-load ratios (see legend).

The results of the type of calculation shown in Fig. 1.1 will be used to guide the calculations in the more complete models RESOLVE and SWITCH. RESOLVE has been chosen because it is being used by the CEC for other evaluations while SWITCH will provide an independent means of understanding the uncertainties in the modeling.

An overview of RESOLVE and SWITCH is given in Table 1 describing the data elements of the two models. The rightmost column of Table 1 shows how the various elements of the models are organized in the Baseline Description (associated deliverable) and the Modelling Approach Description (this document).

Files for each type of information are indicated in blue. The rightmost column defines section of the Baseline Description (this report) or Modeling Approach (companion deliverable) in which we discuss these model elements.

Table 1. 1 Overview of RESOLVE and SWITCH and guide to document.

Category of information	Type of information	RESOLVE	SWITCH	Section
Model details	Identifies modeling selected features	Features are identified as TRUE to select and FALSE to turn off feature_toggles.csv	Scripts that are loaded to the pyomo object are listed in modules.txt. SWITCH version is in SWITCH_inputs_version.txt	Section 2
	Baseline parameters	Modeling numbers that are not varied by the model, but may vary by period, including 11 baseline/scenario costs and five other values (including input carbon price and transmission losses) inputs_passthrough.csv		
	Discount factors	Discount factors and number of years in each period period_discount_factors.tab	Base year, discount rate (5%) and interest rate (7%) financials.csv.	
Time definitions	Periods	Is labeled by the year and is associated with the GHG emissions and renewable energy targets as well as with costs	The investment period is identified by a label and by starting and ending years in periods.csv	Section 3
	Continuous interval	RSP inputs use 24-hour days	timepoints.csv	
	Time step length	Fixed by code to by 1-hour time steps with all timepoints defined in timepoints.tab	A variable time step can be defined in timeseries.csv with Timeseries name, period, duration of timepoint, # of time steps and scaling factor for the period.	
	Selected intervals	RSP chooses 37 days and weights them to represent generation and load profile statistics representing a year day_weights.tab	The timepoints have an id (e.g. 1), a timestamp (e.g. 2025011512) and a timeseries (e.g. 2020_all) as given in timepoints.csv	
Resource definition	Groups of resources	Includes 25 groups of solar resources and 12 groups of batteries capacity_groups.tab		Baseline description
	Generation	Generation resources are described by technology (technologies.tab) and zone, and whether they count in various tallies resources.tab The technologies have	Generation resources are described by technology (non_fuel_energy_sources.csv) and zone.	Baseline description

Category of information	**Type of information**	**RESOLVE**	SWITCH	**Section**
		attributes regarding ramp rates, minimum up and down times, shut-down and start-up costs tech_dispatchable_params.tab and fuel requirements tech_thermal_params.tab	Maximum age, minimum build capacity, scheduled and forced outage rates, type of generation (baseload, variable), energy source and heat rate generation_projects_info.csv	
	Storage	Storage resources are described by efficiency & minimum duration tech_storage_params.tab		Baseline description
Resource definition	Costs - fixed	Fixed annual CapEx and O&M costs by vintage (period when resource was built) for generating resource_vintage_params.tab and storage resources resource_vintage_storage_params.tab	Generator overnight cost and fixed O&M costs by build year in gen_build_costs.csv	Baseline description
	Costs - variable	Cost of fuel fuel_prices.tab by fuel type, period and month	Fuel costs are given for each load zone and period in fuel_cost.csv	Baseline description
	Planned builds	Planned builds of each resource reflect existing generators/storage and planned new builds and retirements planned_installed_capacities.tab planned_storage_energy_capacity.tab Minimum cumulative builds may be specified for each resource for each period. For example, in the RSP, Li batteries are required to be built min_cumulative_new_build.tab	Build limits for generation projects in generation_projects_info.csv	Baseline description
	Build limits	Specified maximum cumulative build for each resource for each period. May reflect available sites and/or practical time to market capacity_limits.tab Specified maximum cumulative build for each group of resources (solar and batteries) for each period flexible_params.csv	The predetermined cap for each project and for each year is in Gen_build_predetermined.csv and generation_projects_info.csv	Baseline description
	Details	Demand management program description conventional_dr_period_limits.tab. Solar and wind resources that may be curtailed resource_variable_renewable.tab. Cost associated with being curtailed zone_curtailment_costs.tab.	Project details include technology, zone, connection cost, capacity limit, heat rate, O&M, minimum build, outage rate generation_projects_info.csv	Baseline description

Category of information	Type of information	RESOLVE	SWITCH	Section
	Hydro details	Expected hydro energy available for each hydro resource for each day with min and max limits hydro_daily_params.tab Ramp time and rate hydro_ramps.tab for CAISO Hydro and any other hydro resources hydro_resources_ramp_limited.tab		Baseline description
Regions and transmission	Definition of regions to be modeled	Uses seven zones zones.tab.	Load zones with cost multiplier load_zones.csv. The load zones are linked to a balancing area in zone_balancing_areas.csv	Section 5
	Definition of transmission zones	RSP has 23 transmission zones tx_zones.tab and further subdivides those into 48 resource transmission zones with characteristics resource_tx_zones.tab. Resource transmission zones are assigned to a transmission zone in resource_tx_zone_map.tab. Direction of flow simultaneous_flow_group_lines.tab for simultaneous flow groups simultaneous_flow_groups.tab		
	Transmission	Transmission lines are defined according to which zone they start and end in, the min and max flows, whether more can be built, etc. transmission_lines.tab. Hurdle rates (per MW) are given for transmission between zones for each period hurdle_rates.tab. Flow limits for each period simultaneous_flow_limits.tab	Transmission lines start and end, length, efficiency, & cap Transmission_lines.csv	
Reliability	Reserve margin	Planning reserve margin metrics for each period including a 15% reserve margin, peak load, annual load and planned imports planning_reserve_margin.tab. Penalties and other parameters system_params.tab	Planning reserve margin defaults to 15%. balancing_areas.csv gives quick start and spinning reserve margins by zone; quick start reserve is 3% of load plus 5% of solar and wind.	Section 4
	Margins required by timepoint	Reserve margins for each type of ancillary service for each timepoint reserve_timepoint_requirements.tab		
	Eligible resources	Available ancillary services reserve_resources.tab		

Category of information	Type of information	RESOLVE	SWITCH	Section
	Net qualifying capacity (NQC) fraction	NQC except for wind and solar (see next line). Dependence of the NQC on penetration of batteries is handled by defining multiple batteries and giving decreasing NQC for those built later resource_prm_nqc.tab		
	Electric load carrying capacity (ELCC) for solar and wind	ELCC coefficients for solar and wind as a function of solar and wind penetration elcc_surface.tab. the inclusion of a resource in the count of solar and wind penetration is in resource_variable_renewable_prm.tab		
	Maintenance derate values	Specified for each resource and as a function of timepoint without explicitly listing the timepoints flexible_params.csv		
	Generation profile and annual capacity factors	Fractional output (relative to plant rating) for each timepoint for solar and wind shapes.tab. Annual capacity factors for solar and wind resource_variable_renewable_prm.tab	The fractional output (relative to the plant rating) as a function of timepoint for solar and wind variable_capacity_factors.csv.	
Base loads and Policy-driven loads	Load	The load (including efficiency, electrification in general) for each zone and each timepoint zone_timepoint_params.tab	Load for each zone and timepoint loads.csv.	Baseline description
	EV Charging efficiency	Charging efficiency for fleets ev_params.tab		Section 6
	EV batteries - Energy	Energy capacity and minimum charge for each fleet of EVs and period ev_period_params.tab		
	EV batteries - Power in and out	Power for drain of EV batteries and power plugged in for each EV fleet and at every time point ev_timepoint_params.tab		
	Hydrogen load definition	Minimum power and total energy for each hydrogen electrolyzer for each period and day hydrogen_electrolysis_daily_params.tab		
Policy Actions	Renewables targets	RPS targets for each period including definition of retail sales and targeted fraction of retail sales. RPS		Section 7

Category of information	Type of information	RESOLVE	SWITCH	Section
		targets 87% of retail sales in 2045 renewable_targets.tab		
	GHG targets	Targeted tons of CO_2 emitted per year for each period. A credit is also indicated for each period. ghg_targets.tab		
	Emissions rates	Tons of CO_2 emitted per MMBTU for each fuel type fuels.tab Tons of CO_2 emitted per MWh associated with imports and exports as a function of period. RSP set to 0.428 for imports to CAISO, set to 0 for exports from CAISO ghg_import_rates.tab	CO_2 intensity and upstream CO_2 intensity fuels.csv	

The version of RESOLVE described in Table 1.1 was not designed to study long-duration storage. E3 is in the process of revising RESOLVE to be more suitable for studying long-duration storage. We anticipate that they will enable use of data sets with 365 days and that they will enable adjustment of the time steps, as discussed in Section 3. They have also indicated plans to create more data sets. Additionally, RESOLVE has not traditionally been used to model a wide range of weather data sets. We propose use of RESOLVE in an expanded way, which may require additional changes to RESOLVE after the revisions made by E3. We will update our approach in the next months when the long-duration storage version of RESOLVE becomes available.

2. Model details

Reference System Portfolio as starting point for inputs for RESOLVE

As described by the CEC[1]: "The RESOLVE model … was based off the model used in the 2019/2020 California Public Utility Commission's (CPUC) Integrated Resource Planning (IRP) process. The CPUC uses RESOLVE to develop the Reference System Portfolio, a look into the future that identifies a portfolio of new and existing resources that meets the GHG emissions planning constraint, provides ratepayer value, and responds to reliability needs. The CPUC uses RESOLVE for the development of the Reference System Portfolio because it is a publicly available and vetted tool. The CPUC uses the process of soliciting party feedback on inputs and assumptions to ensure that RESOLVE contains transparent, publicly available data sources and transparent methodologies to examine the long-term planning questions posed within the IRP process."

The scenario "46MMT_20200207_2045_2GWPRM_NOOTCEXT_RSP_PD" provides a publicly vetted starting point:

- This is the "Reference System Portfolio" or "RSP"
- 46MMT stands for 46 million metric tons and reflects a 56% decrease in emissions compared to 1990 levels, to be achieved by 2030.
- 2GWPRM means The Planning Reserve Margin = 2 GW. Peak loads in California are typically ~ 50 GW, so this means ~4% reserve margin.
- NOOTCEXT indicates "no OTC Extension" OTC = Once through cooling takes billions of gallons of water each day out of oceans, rivers, or… and then returns it at a higher temperature, affecting ecological systems. These plants were planned to be shut down by Dec. 2020, but the following will remain open: Alamitos Generating Station Units 3, 4, and 5 for three years until December 31, 2023; Huntington Beach Generating Station Unit 2 for three years until December 31, 2023; Ormond Beach Generating Station Units 1 and 2 for three years until December 31, 2023; and, Redondo Beach Generating Station Units 5, 6, and 8 for one year until December 31, 2021. The first year after 2020 we intend to model is 2025, so, unless these are extended even longer, no change is needed.
- RSP is short for Reference System Plan or Reference System Portfolio

The current version of SWITCH WECC was constructed to incorporate the baseline case from the California Energy Commission demand projections without SB350 savings, and a low rate of electrification for 2030 and 2050. We consider two baseline scenarios for carbon cap, one with zero emissions WECC-wide by 2050 and 80% emissions reductions from 1990 levels by 2050. Additionally, for both scenarios a California carbon cap is modeled to attain 40% emissions reductions by 2030. All current Renewable Portfolio Standards are modeled for each load zone in the WECC as unbundled.

Fuel prices projections were obtained from the United States Environmental Information Agency (EIA) (2017). Capital costs and operation and maintenance costs were obtained from NREL-

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[1] "SB100 Joint Agency Report: Charting a path to a 100% Clean Energy Future," TN#234532, published by California Energy Commission, Aug. 31, 2020, page 4. https://www.energy.ca.gov/sb100.

ATB 2020. The current pool of existing power plants in the WECC was also obtained from EIA (EIA-860, EIA-923, 2018 data). Hydropower historical generation was also obtained from EIA-923 data.

SWITCH has available different load scenarios and for this project we are using the aggressive EE with Electrification as our baseline. The following are the available load scenarios that depict how the baseline was constructed:

The Frozen Demand case: This case essentially assumes baseline CEC-IEPR demand projections without SB350 savings, and a low rate of electrification to 2030 and 2050.

SB350: This case achieves the SB350 target of doubling the rate of energy efficiency by 2030. A low rate of electrification for buildings is assumed.

SB350 + Electrification: This scenario is the same as the SB350 scenario but adds aggressive building electrification starting in 2020.

Aggressive EE without Electrification: This scenario assumes a higher rate of energy efficiency retrofits starting in 2020 than the SB350 case but with a low rate of building electrification.

Baseline: Aggressive EE with Electrification ("Compliant") case: This case is similar to the preceding case but with aggressive building electrification starting in 2020 and more aggressive adoption of ZEVs in transportation (BEV and FCEV) and electrified and fuel cell-powered trucks

2.1 Locational differentiation

RESOLVE uses wind and geothermal Capex and O&M costs that vary by location, as described in the Baseline Description, Section 3, but the solar costs do not vary by location.

SWITCH does not differentiate cost by location for any of the resources. SWITCH has the capability to apply regional economic multipliers, but we have chosen not to use this feature in the baseline.

2.2 Financial assumptions

Every financial calculation needs to keep track of key financial parameters. Table 2.1 summarizes how interest rates, inflation rates, discount rates and incentive programs are handled in RESOLVE and SWITCH.

Table 2. 1 Financial assumptions of RESOLVE and SWITCH

Financial element	**RESOLVE** - RSP	**RESO**LVE - proposed	**SWITCH**
Interest rate	Technology specific – included in calculating the annualized cost of the CapEx	No change	5% for all
Discount rate	Discount rate (5%/y) is defined in a file called period_discount_factors and is applied to all costs in the period when an expenditure is made.	Sensitivity analysis suggests that it has minimal effect	5% for all
Incentive programs	Annualized costs are adjusted to reflect incentives.	Adjust annualized costs to reflect Dec 2020 action by Congress	Include in overnight costs

2.2.1 Interest rates:

The interest rates expected for financing projects may depend on the maturity/risk for each technology. The NREL ATB includes an estimate of the financing costs, including interest rates and related financing costs, in their analysis. The RESOLVE RSP includes these for each technology when defining the annualized costs. They are documented in the input files.

SWITCH calculates the annualized costs from the overnight (upfront costs) at the beginning to the calculation and applies a single interest rate (5%) for all technologies.

2.2.2 Inflation rate:

We plan to use constant 2018 dollars for all of the evaluations, though we note that the uncertainty in most of the numbers is greater than the difference between 2016, 2018, and 2020 dollars. The inflation rate has been fairly low in recent years, around 2% to 2.5%. We anticipate that an increased inflation rate could slow adoption of renewable and storage technologies because of the generally high upfront investment, but that the inflation rate will have little effect on the relative adoption of the different storage technologies. One of the TAC members raised the question of the effects of increased inflation rates, but advice from other TAC members concluded that we should focus on studying the duration of the storage needed over a factor such as this.

2.2.3 Discount rate:

The RESOLVE RSP and SWITCH both apply a 5% discount rate to the costs that are optimized, motivating the optimization to choose to build resources in a later year.

When discussing the application of the discount rate, it is interesting that those investing in projects apply a discount rate to the cash flow, concluding that it is better to invest in a project sooner to have the more valuable cash flow today rather than years later. In contrast, the application of the discount rate in RESOLVE and SWITCH discounts the costs incurred in later years, motivating delay in investment as long as possible. This begs the question of which perspective is more relevant to the CEC.

We anticipate that investments will be mostly driven by the requested RPS and GHG targets, so the discount rate may not have much effect on what is spent, but when we compare results of the RSP with 5% discount rate and 0% discount rate we have found that there is a small effect as shown by Fig. 2.1. The new built capacity in 2045 for the 5% discount rate was > 50 GW, but about 50 GW or less for the 0% discount rate. Surprisingly, some geothermal was built later in the 0% discount rate case while some wind was built earlier. At first glance, the discount rate has very little effect, but there could be situations in which it has a greater effect.

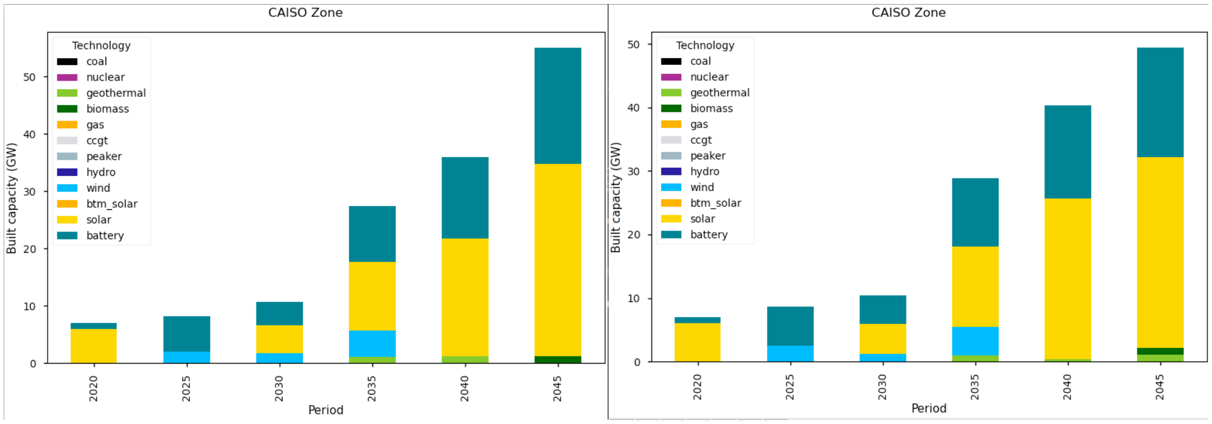

Fig. 2. 1. Comparison of RESOLVE build out with discount rate of 5% (left) and 0% (right).

3. Model time definitions

Our study of long-duration storage is differentiated from the traditional capacity expansion planning in two ways: 1) our focus is on long-duration storage, which requires understanding seasonal storage in addition to short-duration storage, and 2) we are more focused on what happens as we approach the 2045 time frame and how the market evolves to get there and not interested in the details of meeting the grids needs in the next year or two. We note that California must place a high priority on preparing for reliable grid operation in 2021 and 2022, especially in lig ht of the emergency that was declared in August 2020, but this study is focused on the longer term.

3.1 Period definitions

The current Reference System Portfolio (RSP) for RESOLVE uses periods 2020, 2021, 2022, 2023, 2024, 2026, 2030, and 2045. SWITCH has historically used 10-year increments. While there is value to California in being able to study the anticipated changes in the coming years in substantial detail, the study of the value of long-duration storage has different needs. In particular, we know that the role of long-duration storage will change as more solar and more storage are deployed. We define a baseline that uses 5-year increments: 2020, 2025, 2030, 2035, 2040, 2045. Doing so will enable us to better study the steps in the transition. A comparison of the resulting capacity expansion is shown in Fig. 3.1. The scale on the left graph, representing the current RSP periods, is expanded to accommodate the massive build out that is required between 2030 and 2045. The scale on the right graph is smaller, enabling us to better understand the incremental build out and how it changes with time. While we intend to use 5-year periods, we may need to modify this plan if this turns out to be computationally problematic.

Table 3. 1 Discount factors in RSP and in proposed 5-year Baseline.

RESOLVE RSP			RESOLVE modified to 5 year periods		
period	**discount_factor**	**years_in_period**	**period**	**discount_factor**	**years_in_period**
2020	1	1	2020	2.82	3
2021	0.95	1	2025	3.94	5
2022	0.91	1	2030	3.08	5
2023	0.86	1	2035	2.42	5
2024	1.21	1.5	2040	1.89	5
2026	2.17	3	2045	1.48	5
2030	4.97	9.5	2050	1.16*	3*
2045	6.70	28			

*The RESOLVE Scenario tool assigns these to reflect 23 years into the future. We have chosen to reduce the number of years in the final period.

The build out between 2035 and 2045 is dominated by solar and battery storage. The amount of solar and storage needed is mostly driven by the requested emissions targets for each year. These will be discussed in section 7. The use of 5-year periods will also enable us to study the results as a function of the emissions requirements.

The effect of changing the periods studied has minimal effect on the final grid configuration in 2045, as shown in Fig. 3.2.

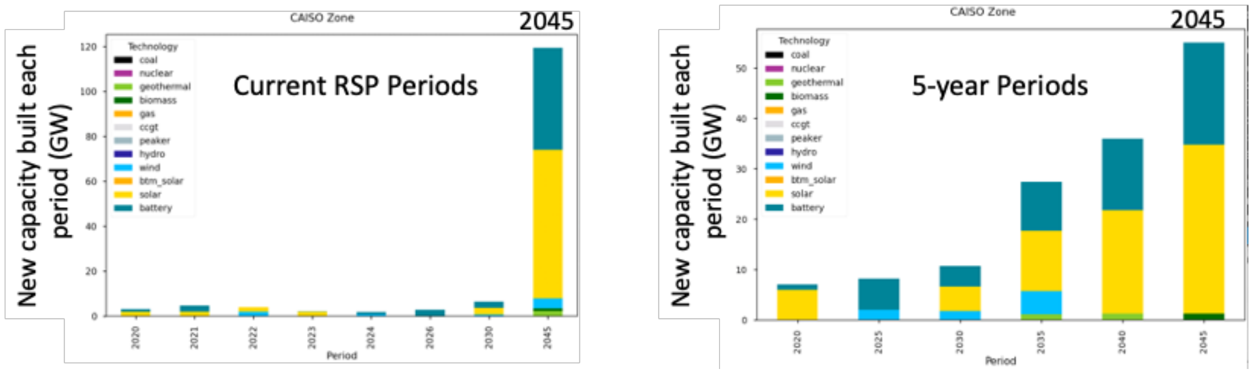

Fig. 3. 1. New capacity built by RESOLVE for two choices of periods

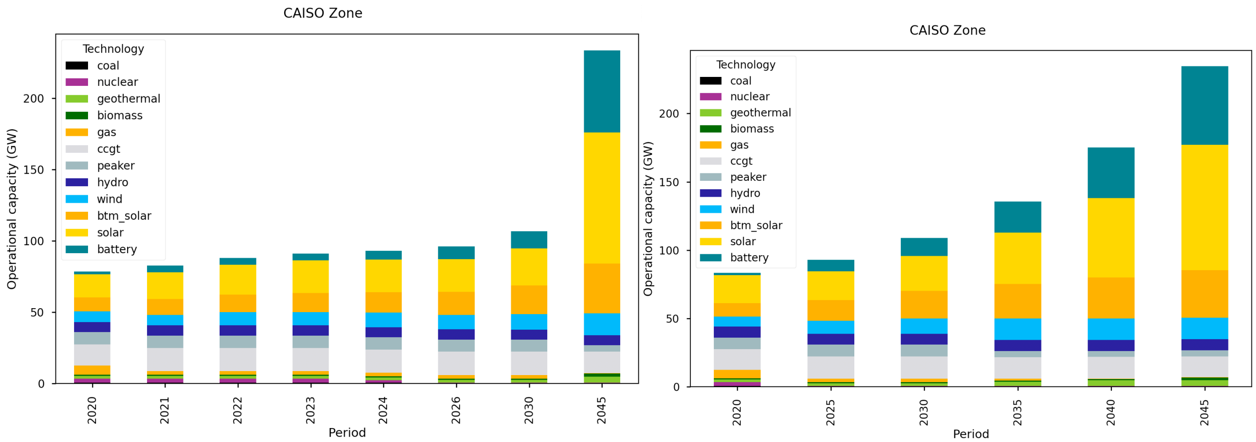

Fig. 3. 2. Operational capacity selected by RESOLVE for two choices of periods

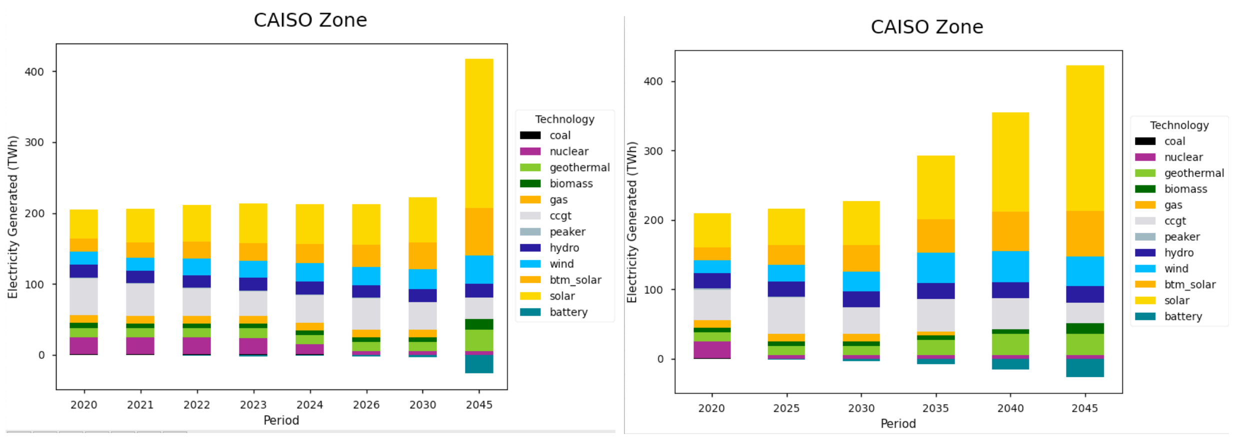

Fig. 3. 3. Annual electricity generation from RESOLVE for two choices of periods

3.2 Weather 365-contiguous-day definition

The 37 individual days in the RSP RESOLVE code do not allow us to capture the need for seasonal storage that is very evident in Fig. 1.1. The new version of RESOLVE will enable us to do these calculations gracefully, and it is our plan to model 365-day (8760-hour) data for our main studies with RESOLVE.

While the RESOLVE revision is under development, we modified RESOLVE to run a single 8760-hour day. This is done by revising the model_formulation.py code by replacing “24” with “8760” in three places: line 1784 (which defines the number of timepoints per day) and lines 4274 and 4278 which deal with demand response for a horizon of < 1 day. Additionally, the following files were modified:

- The day_weights.tab file was modified to reflect a single day with weighting of 1.
- The shapes.tab file was modified to use the CAISO data for 2019 for the existing solar resources and to use PVWatts simulations for 2019 for the candidate resources.
- The shapes.tab file was modified to use the same wind data for each resource as in the 37 days, but repeating the 37-day sequence.
- Recreate the timepoints.tab file to define the 8760 timepoints used in the simulation.
- Modify the following files to reflect the new set of timepoints: zone_timepoint_params.tab, reserve_timepoint_requirements.tab, ev_timepoint_params.tab, flexible_params.csv, fuel_prices.tab, hydro_daily_params.tab, hydrogen_electrolysis_daily_params.tab
- If the hydrogen_electrolysis_daily_params.tab file has non-zero data, the ratio of the MW and MWh/day must be scaled to be realistic.
- The load data were taken from the CAISO 2019 data and reproduced for each of the seven zones, scaling the load to have the same relative loads as for the seven zones in the RESOLVE RSP.

Use of the 2019 solar data for all solar resources loses geographical resolution for the solar, but gives a very accurate representation of the solar generation. The use of repeated wind data gives realistic data for each site, but does not capture the correct variability of the wind with season. This introduces error in the modeling, but the fraction of electricity supplied by wind is small enough that the primary conclusions will not change. Other seasonal effects, such as the variation in availability of hydropower with time of year are also lost.

A comparison in the results for the 37-separate-day and 365-contiguous-day simulations is shown in Figs. 3.4 and 3.5. The results are remarkably similar. Figs. 3.6-3.12 show the state-of-charge for the lithium batteries and for the pumped hydro storage throughout the year for the simulations for 2020, for 2045 with the RSP emissions target, and for 2045 with an emissions target of zero. The lithium battery state of charge reflects daily charging and discharging for most days, while the pumped hydro state of charge reflects the seasonal variation, as we would expect from Fig. 1.1.

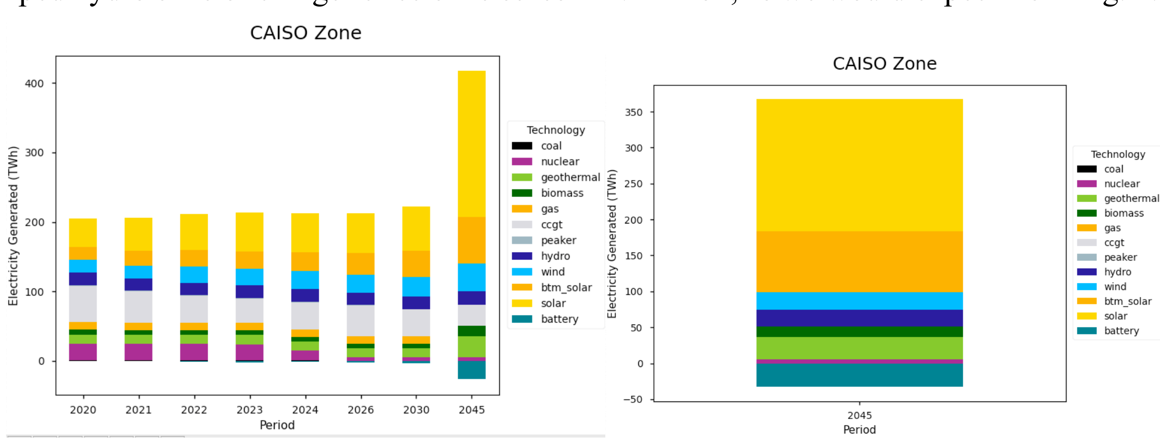

Fig. 3. 4. Electricity generation for 37- and 365-contiguous-day in 2045 models

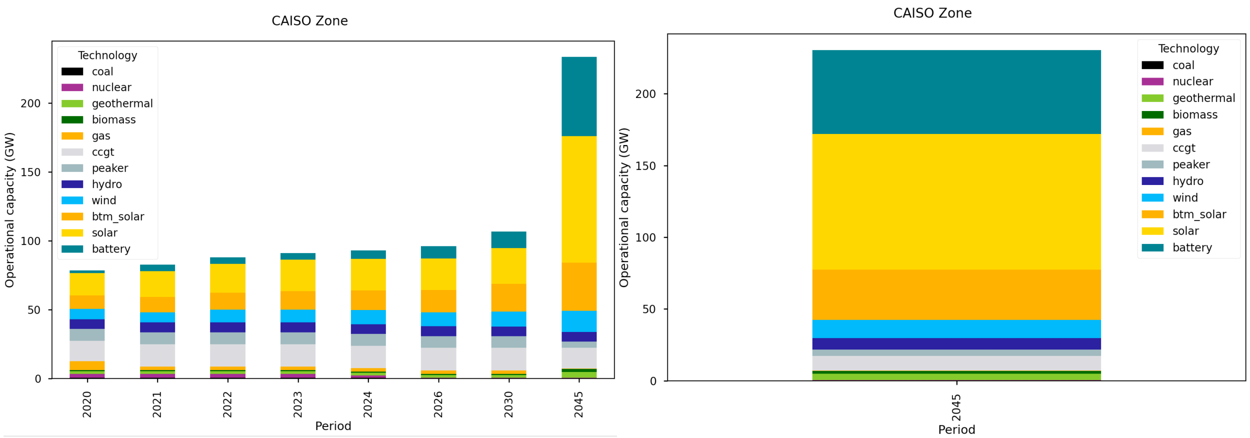

Fig. 3. 5. Operational capacity for 37- and 365-contiguous-day in 2045 models

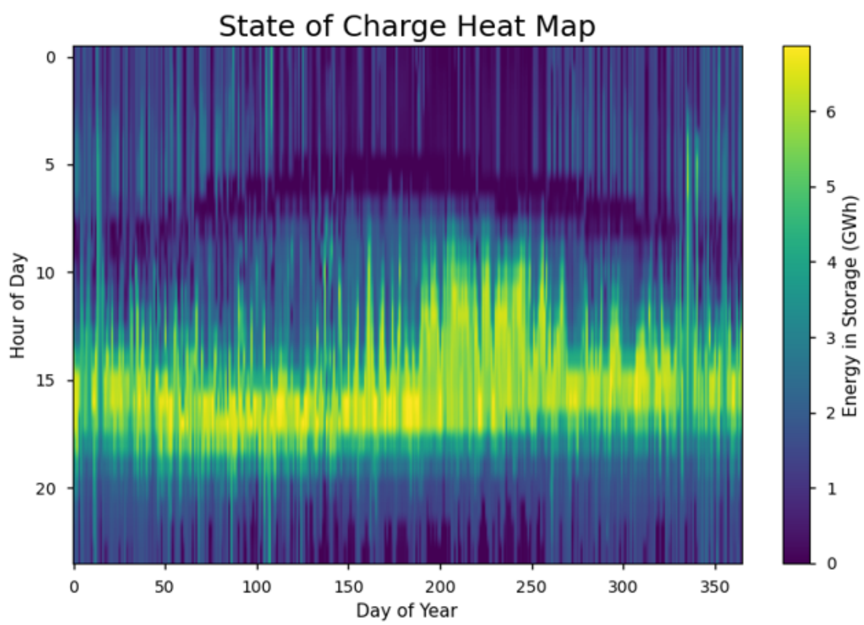

Fig. 3. 6. State of charge of Li ion storage for 2020 365-contiguous-day simulation

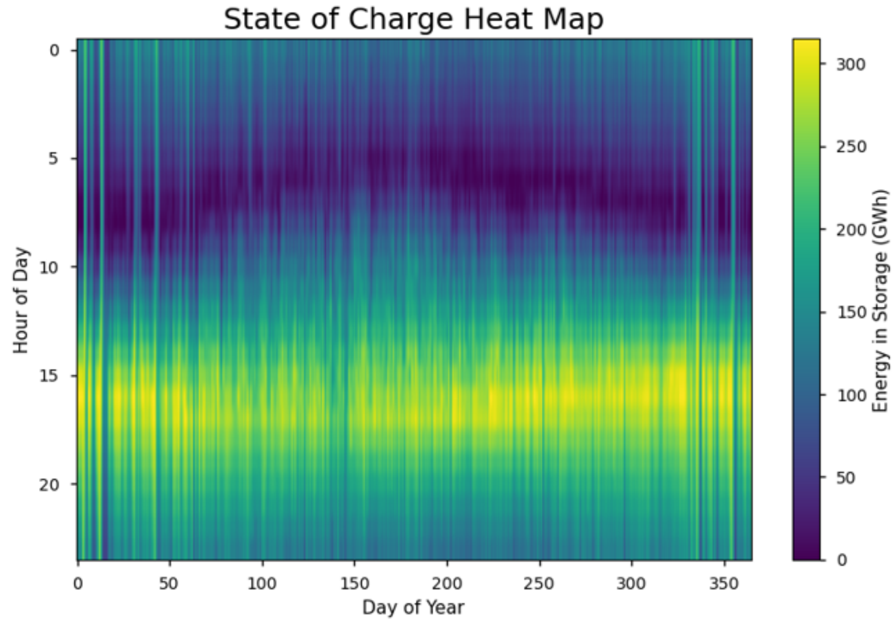

Fig. 3. 7. State of charge of Li ion storage for 2045 365-day simulation with RSP emissions requirement

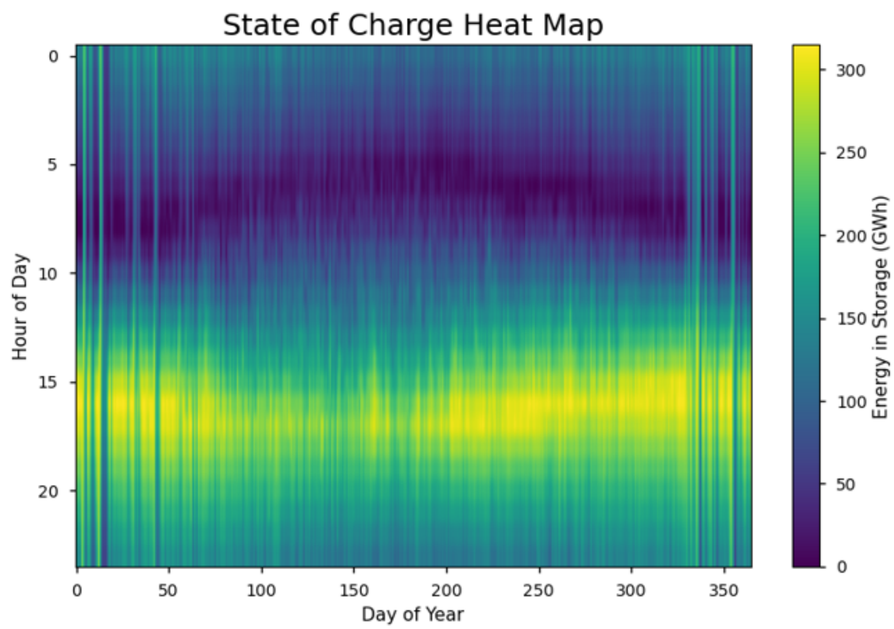

Fig. 3. 8. State of charge of Li ion storage for 2045 365-day simulation with emissions requirement of zero.

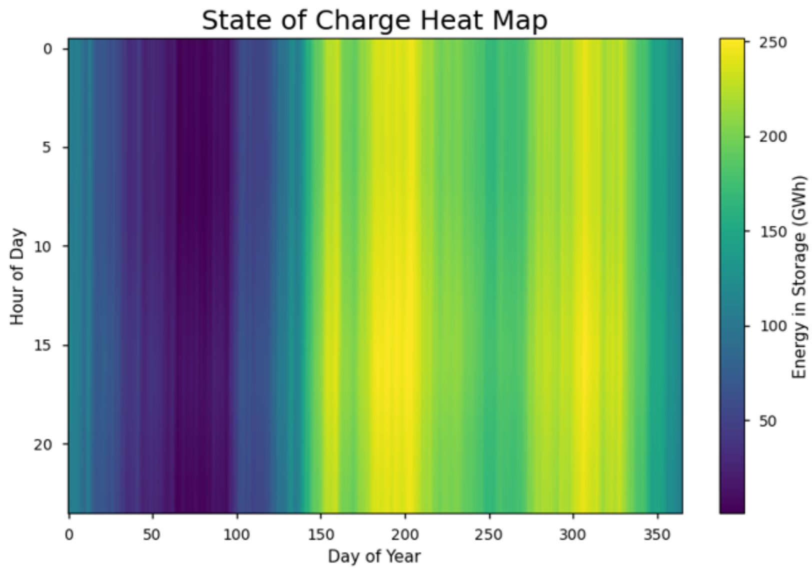

Fig. 3. 9. State of charge of pumped storage for 2020 365-day simulation

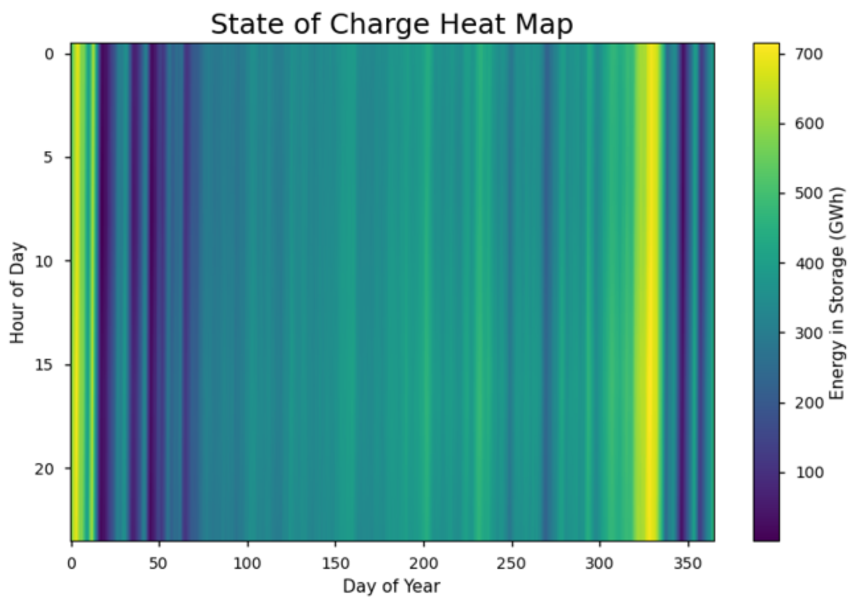

Fig. 3. 10. State of charge of pumped storage for 2045 365-day simulation with RSP emissions requirement

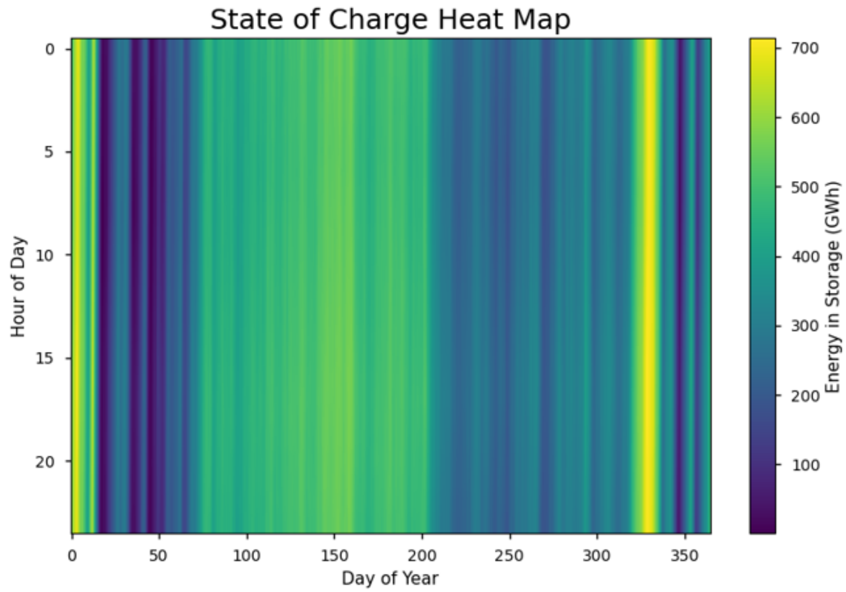

Fig. 3. 11. State of charge of pumped storage for 2045 365-day simulation with emissions requirement of zero

Once the new version of RESOLVE is available, we will need to revisit the definition of the contiguous days, but we are anticipating that modeling 365 contiguous days will be an easily accessed feature of RESOLVE in the new version. However, modeling of 8760 timesteps per year/period can lead to very long simulation times. Reducing the number of timesteps will be very useful, as discussed in the next section.

3.3 Timestep definition

The stability of the grid requires instantaneous balancing of supply and demand, but understanding long-duration storage is focused on longer time horizons. Inspecting Fig. 1.1 and adding analysis of Fig. 3.12, we see that the storage can be maintained as mostly full during the summer, then is depleted in an annual cycle reflecting the reduced availability of solar energy in the winter. The data suggest that the following time horizons may be differentiated:

- **Seasonal:** Understanding seasonal issues requires modeling from November to May, though in a year like 2020 when there were exceptional fires, the seasonal decrease began in August and some years did not fully recover the storage to full charge until June. This time horizon is affected by the solar investment, as shown in Fig. 1.1, and by other factors.
- **Daily**: The diurnal cycle of charging during the day and discharging at night can be studied by considering 24-hour days, but the statistics of the diurnal cycle vary throughout the year. The interaction between the nighttime storage (requiring 10-15 hours of storage) with the seasonal storage will affect the use of the diurnal storage.
- **Events**: In Fig. 3.7, we can see that there are irregular dips in the data. The satellite photos shown in Fig. 3.7 show how clouds (as on July 25th 2019) can lead to a temporary depletion of the storage. We anticipate that the dips seen in Fig. 3.7 arise from clouds, smoke, or other events that lead to a net shortage of electricity over a few days. The dips are seen to vary from a short time (a day or two) to about a month (as seen in September 2017) or even to multiple months (as seen from August through November in 2020 or in October and November in 2015).

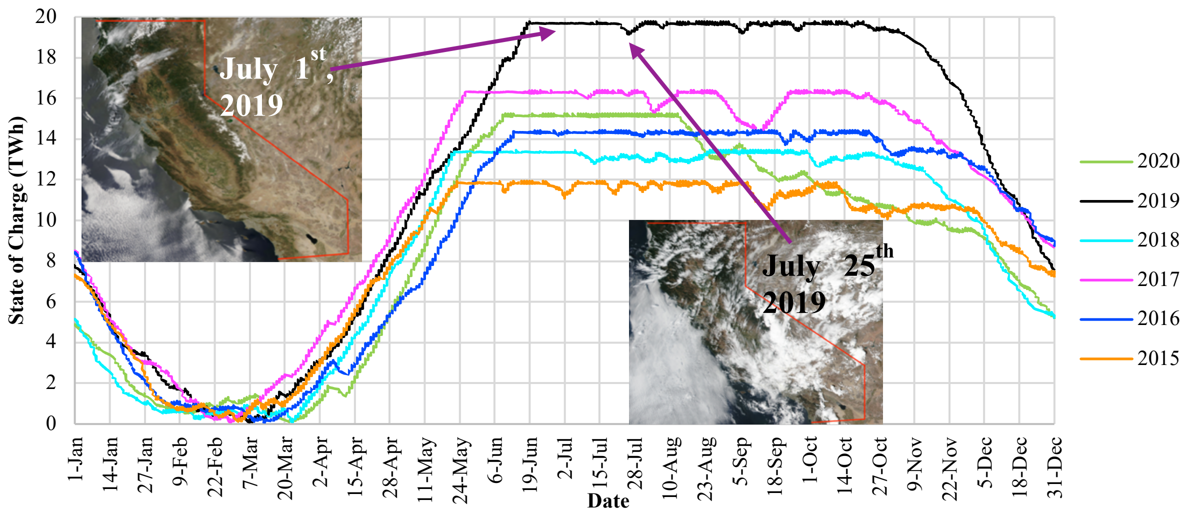

Fig. 3. 12. Stored energy (Fig. 1.1) with solar build supplying 15 TWh/y of surplus electricity

Our goal of quantifying the relative amounts of short- and long-duration storage (including the relative amounts of variable types of long-duration storage) requires that we simultaneously model these. However, it is not clear that hourly calculations are required since California's fleet of storage is currently comprised of 4-hour and longer-duration storage.

The daily charging and discharging of the storage typically result in a minimum state of charge one to two hours after sunrise and a maximum state of charge one to two hours before sunset as shown in Fig. 3.13.[2] While the details of the dispatch of that storage may depend on the hourly simulation, the calculation of the needed storage capacity depends primarily on these minima and maxima. Thus, in general, we may select two timesteps each day as shown by the red dots in Fig. 3.13. After the capacity expansion is optimized, we may optimize the dispatch on an hourly basis using the selected capacity expansion. The linear optimization of the dispatch can be done a year at a time using the full 8760 hours of data. Because the computational challenge scales closer to the square of the number of timepoints/calculations, we may complete the calculations faster by calculating the optimal dispatch one year at a time.

Thus, we propose to reduce the computational complexity by completing the capacity expansion optimization using two timesteps per day, then optimizing the hourly dispatch in a second calculation, preferably using variable weather data sets to test the reliability. This approach is very consistent with the way results would be implemented in the real world. Any surprises that occur during the dispatch will inform an improved version of the capacity expansion modeling, perhaps by revising the approach to determining the needed reserve, as discussed in the next section.

[2] The sunrise and sunset times were selected in this case for California City. A different reference point may be used.

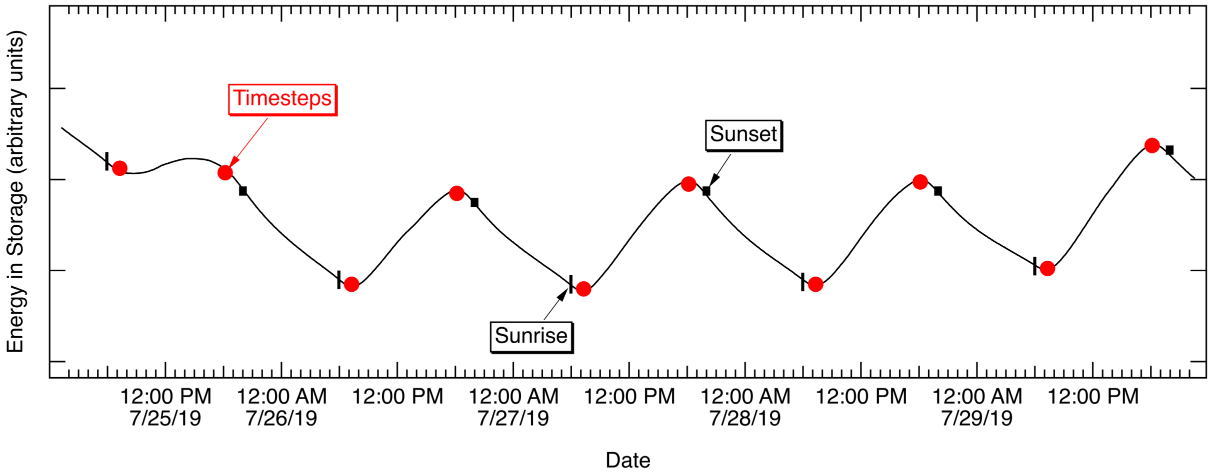

Fig. 3. 13. Stored energy as in Fig. 1.1 compared with sunrise and sunset times

4. Reliability modeling

RESOLVE and SWITCH are both designed to optimize the lowest cost capacity-expansion and dispatch plan for a given set of weather conditions. Neither is designed to do a full analysis of grid reliability in light of variable weather conditions. The CEC has supplemented analysis in RESOLVE with SERVM analysis for the final grid reliability analysis to finalize capacity expansion planning. Our study needs to assess the importance of storage in providing grid reliability. We propose to do this by evaluating multiple weather data sets with each of the modeling tools. Both RESOLVE and SWITCH include elements for ensuring reliability for the specified weather conditions. These are discussed next.

Resource adequacy for a zero-carbon grid will require modeling of both power and energy resources. Many metrics and strategies are used for analyzing resource adequacy. Here we summarize some of these and how they are implemented in the models.

Reserve margin: The available unloaded capacity may be defined as “any portion of online generation capacity that is not serving load and offline generation capacity that can come online in 20 minutes or less to serve load as well as curtailable demands such as demand response, interruptible pumping load, and aggregated participating load that can provide non-reserve or demand reduction.”[3]

In modeling the reserve margin, both RESOLVE and SWITCH use 15%, as shown in Table 4.1. These are applied on top of the peak loads, which are summarized for RESOLVE in Table 4.2. In SWITCH, the loads are specified for each zone, so a full summary of the peak loads would be a long table, so is not included here.

Table 4. 1 Reserve margins used by models

Model	Reserve margin
RESOLVE RSP	15%
SWITCH	15%

Table 4. 2 Peak loads used in RESOLVE

Period	Peak load RESOLVE (MW)	Peak load RESOLVE (MWh)
2020	49,407	242,189,141
2025	51,212	252,817,017
2030	53,486	257,017,851
2035	56,130	301,356,571
2040	58,780	345,695,292
2045	61,433	382,705,923

[3] https://www.caiso.com/Documents/2020SummerLoadsandResourcesAssessment.pdf

Calculation of the generating capacity must be done differently for different types of resources and can be dependent on many factors including planned and unplanned maintenance for dispatchable generators and lack of availability for variable resources like solar and wind.

Loss of Load Expectation (LOLE) or Loss of Load Probability (LOLP): Is a metric reflecting the probability of not meeting the required load. A common target is 0.1 days/year or 1 day in 10 years.

Effective Load Carrying Capability (ELCC): The ELCC may be defined as "the capacity amount by which the system's loads can increase when the generator is added to the system while maintain the same system reliability as a probability over a period of time."[4] In 2018, the CPUC began using ELCC as part of its resource adequacy analysis.

RESOLVE uses the ELCC to estimate the system's generating capacity at any time to determine the resource adequacy. SWITCH does not use ELCC.

Expected Unserved Electricity (EUE): The EUE is the expected electricity (energy) not supplied to meet demand during a period of time. The EUE has been suggested as an alternative to LOLE to better assess the tradeoff between reliability and cost.[5]

Imports: CAISO currently relies on imports from nearby states to meet grid requirements. The reliance on imports to meet grid adequacy in the future may be questionable. SWITCH WECC includes imports as part of the calculation. We plan to compare the results of SWITCH and RESOLVE to better understand the potential role of imports in meeting grid requirements and to determine whether the baseline value of 5 GW of imports is a reasonable design metric for RESOLVE. The inclusion of some imports is important because some plants, such as Hoover, Palo Verde, and Intermountain Power Plant have served California load despite being outside of California, but we anticipate that these will play only indirect roles in determining the role of long-duration storage in meeting grid adequacy.

[4] http://www.caiso.com/Documents/IssuePaper-GenerationDeliverabilityAssessment.pdf
[5] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

5. Regions and transmission

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

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

In addition, load area boundaries are defined to capture as many currently congested transmission corridors as possible (Western Electricity Coordinating Council 2009). These pathways are some of the first places where transmission is likely to be built, and exclusion of these pathways in definition of load areas would allow power to flow without penalty along overloaded transmission lines.

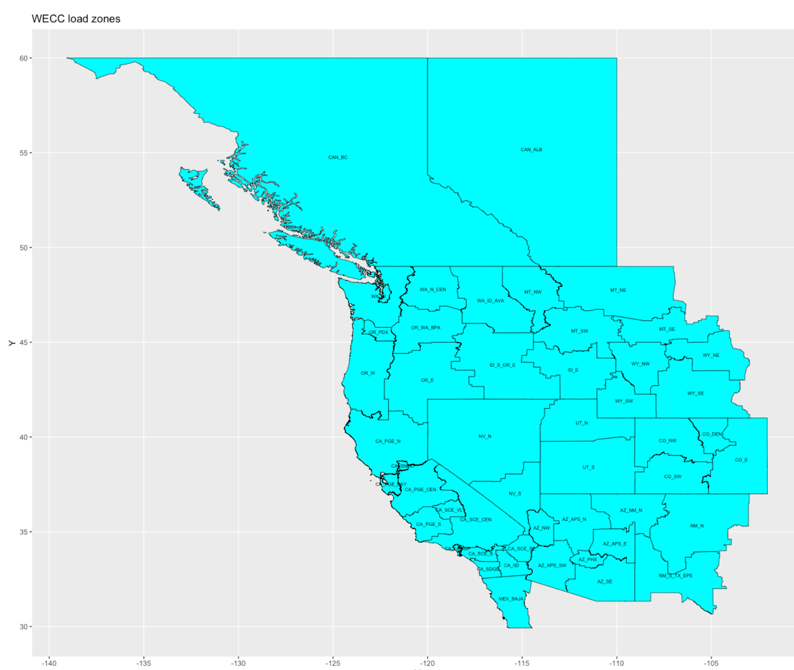

Figure 5. 1 WECC load zones incorporated in the baseline of SWITCH.

The existing transmission capacity between load areas is found by matching geolocated Ventyx data (Ventyx EV Energy Map) with Federal Energy Regulatory Commission (FERC) data on the thermal limits of individual power lines (FERC). A small fraction of lines present in the Ventyx database could not be matched to lines found in the FERC database; these lines are ascribed a generic transfer capacity equal to the average transfer capacity of their voltage class. In total, 104 existing inter-load-area transmission corridors are represented in SWITCH WECC.

The largest capacity substation in each load area is chosen by adding the transfer capacities of all lines into and out of each substation within each load area. It is assumed that all power transfer between load areas occurs between these largest capacity substations, using the corresponding distances along existing transmission lines between these substations. If no existing path is present, new transmission can be installed between adjacent load areas assuming a distance of 1.5 the distance between largest capacity substations of the two load areas. The amount of power that can be transferred along each transmission line is set at the rated thermal limits of individual transmission lines. Additionally, transmission power losses are taken into account at 1 percent of power lost for every 100 miles over which it is transmitted. In total, there are 104 existing transmission lines connecting load zone in SWITCH. SWITCH can decide to build more transmission lines if it is optimal between adjacent load zones.

The geographical resolution for RESOLVE RSP is modeled using seven load zones where 4 of them are located in-state, 2 out-state aggregated load-serving entities and 1 buffer zone. The load zones are named as follows:

- CAISO,
- CAISO NW Hydro,
- LDWP,
- BANC,
- IID,
- NW,
- SW.

CAISO is the primary zone of interest for this project. It occupies most of California's territory, while the others load zones include far smaller territories, see Fig. 5.2. Additionally, the RESOLVE model incorporates in-state transmission zones to model transmission flows from candidate resources.

The RESOLVE RSP model simplifies the load zones to reduce computation time while preserving the transmission limits between zones. However, to quantify the value of LDES storage a more detailed geographical resolution is required to properly account for availability of imports and transmission flows between local zones. SWITCH WECC is currently configured to model all WECC balancing zones, providing a contrast to RESOLVE RSP. Also, the current version of RESOLVE RSP does not consider transmission expansion outside of California, while the SWITCH WECC model does. For our baseline SWITCH definition, we will incorporate new transmission between certain load zones as shown in Fig 5.3. This allows a more realistic study of the expansion and operation of the electrical grid for the entire WECC with the presence of renewable variable resources in all the balancing zones.

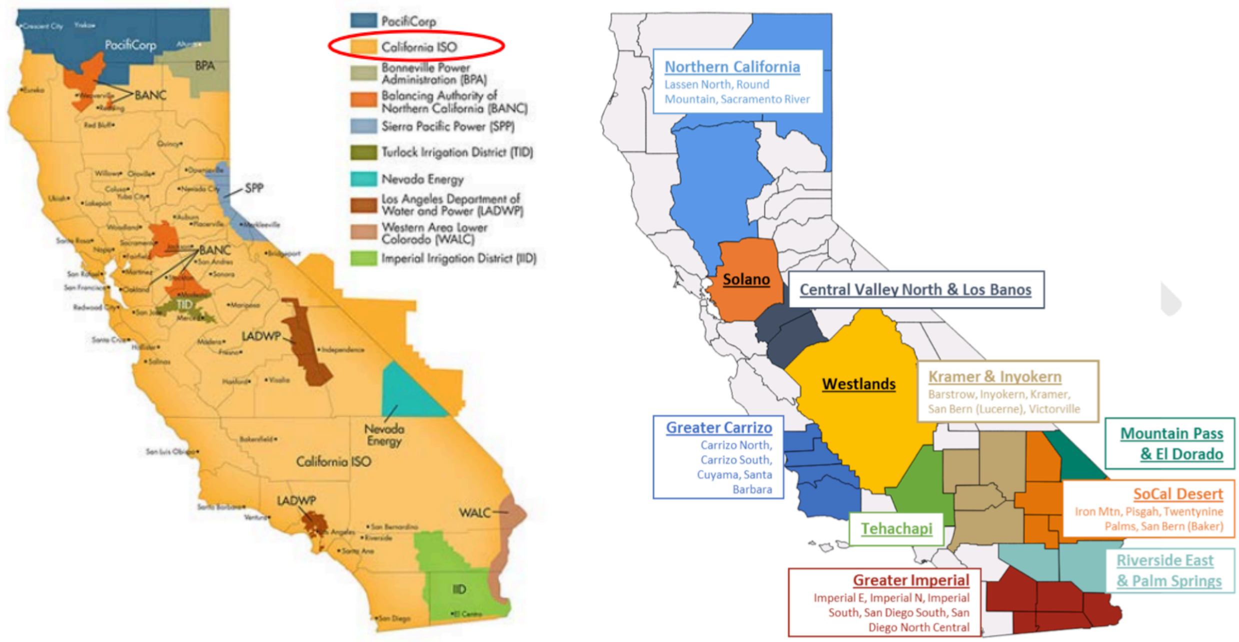

Figure 5. 2. Maps of the RESOLVE RSP Zones and in-state transmission zones.

In addition to the physical underlying transmission topology shown on Figure 5.2, the RESOLVE model includes a constraint on the simultaneous net exports from CAISO which is reported on the current RSP documentation. This constraint does not have a direct equivalent in SWITCH. However, the baseline scenario for SWITCH assumes that 80% of the California load must be served by in-state generation in 2050.

Figure 5.3 shows the existing thermal transmission capacity between the proposed load zones for SWITCH WECC. The black dots in Fig. 5.3 represent the largest substation in each load zone.

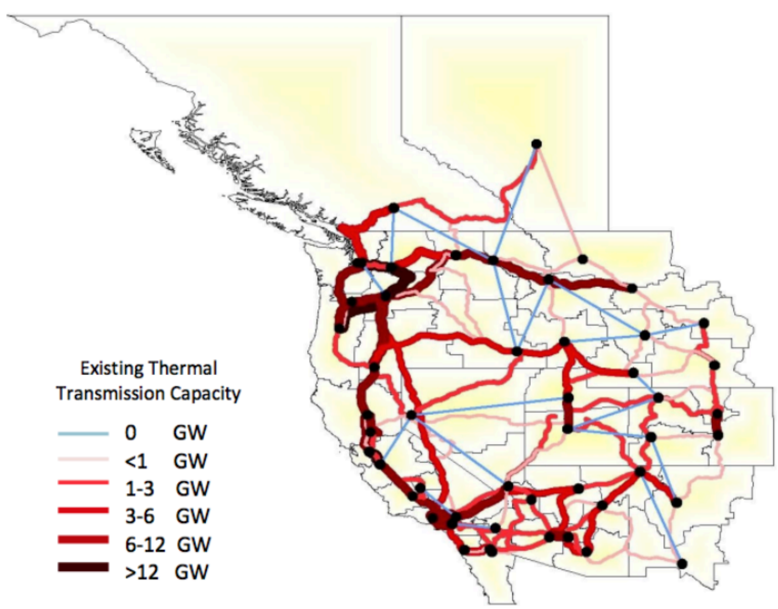

Figure 5. 3 WECC transmission capacity including proposed additions (blue lines)

Table 5. 1 Mapping of load zones for RESOLVE and SWITCH WECC models.

RESOLVE Zone	SWITCH Zone	Applicable Balancing Authorities
BANC	CA_SMUD	Sacramento Municipal Utility District
CAISO & CAISO NW hydro	CA_PGE_BAY	Pacific Gas and Electric (PG&E)
	CA_PGE_CEN	
	CA_PGE_N	
	CA_PGE_S	
	CA_SCE_CEN	Southern California Edison (SCE)
	CA_SCE_S	
	CA_SCE_SE	
	CA_SCE_VLY	
	CA_SDGE	San Diego Gas & Electric
IID	CA_IID	Imperial Irrigation District (IID)
LADWP	CA_LADWP	Los Angeles Department of Water and Power (LADWP)
NW	CO_DEN	Public Service Company of Colorado (PSCO)
	CO_E	
	CO_NW	WAPA – Colorado-Missouri (WACM)
	CO_SW	WAPA – Colorado-Missouri (WACM)
	ID_E	Idaho Power Company (IPC)
	ID_S_OR_E	
	MT_NE	WAPA – Upper Wyoming (WAUW)
	MT_NW	Northwestern Energy (NWMT)
	MT_SE	
	MT_SW	
	OR_E	Idaho Power Company (IPC)
	OR_PDX	Portland General Electric Company (PGE)
	OR_W	PacifiCorp West (PACW)
	OR_WA_BPA	Bonneville Power Administration (BPA)
	UT_N	PacifiCorp East (PACE)
	UT_S	PacifiCorp East (PACE)
	WA_ID_AVA	Avista Corporation (AVA)
	WA_N_CEN	Grant County Public Utility District (GCPD)
	WA_SEATAC	Seattle City Light (SCL), Tacoma Power (TPWR)
	WA_W	Bonneville Power Administration (BPA)
	WY_NE	WAPA – Colorado-Missouri (WACM)
	WY_NW	
	WY_SE	
	WY_SW	
	CAN_ALB	Alberta Electric System Operator (AESO)
	CAN_BC	British Columbia Hydro Authority (BCHA)
SW	AZ_APS_E	Arizona Public Service Company (APS)
	AZ_APS_N	
	AZ_APS_SW	
	AZ_NM_N	
	AZ_NW	
	AZ_PHX	
	AZ_SE	Tucson Electric Power Company (TEP)
	MEX_BAJA	Comisión Federal de Electricidad (CFE)
	NM_N	Public Service Company of New Mexico (PNM)
	NM_S_TX_EPE	El Paso Electric Company (EPE)
	NV_N	Nevada Power Company (NEVP)
	NV_S	Nevada Power Company (NEVP)

Table 5.1 summarizes the equivalent load zones for SWITCH WECC and RESOLVE.

6. Policy-driven loads

6.1 Loads in SWITCH

Table 6.1 summarizes available SWITCH load scenarios. We have selected the last scenario, labelled as "**Baseline**" for our baseline assumptions for SWITCH.

The Frozen Demand case: This case essentially assumes baseline CEC-IEPR demand projections without SB350 savings, and a low rate of electrification to 2030 and 2050.

SB350: This case achieves the SB350 target of doubling the rate of energy efficiency by 2030. A low rate of electrification for buildings is assumed.

SB350 + Electrification: This scenario is the same as the SB350 scenario but adds aggressive building electrification starting in 2020.

Aggressive EE without Electrification: This scenario assumes a higher rate of energy efficiency retrofits starting in 2020 than the SB350 case but with a low rate of building electrification.

Baseline: Aggressive EE with Electrification ("Compliant") case: This case is similar to the preceding case but with aggressive building electrification starting in 2020 and more aggressive adoption of ZEVs in transportation (BEV and FCEV) and electrified and fuel cell-powered trucks.

Table 6.1 SWITCH Load Scenarios

Scenario Name	**Buildings**	**Transportation**	**Industry**
Frozen Demand	CEC-IEPR	Low electrification rate in line with IEPR-2016 (11,000 GWh by 2030 & 19450 by 2050)	CEC-IEPR extended
SB 350 **[without building electrification]**	SB 350 savings till 2030 and holding percentage of savings fixed till 2050	Same as Frozen Demand above	Moderate Energy Efficiency reduced demand
SB 350 + Electrification	SB 350 savings through energy efficiency with intermediate rates of retrofit and electrification	Same as Frozen Demand above	Moderate EE measures + electrification

Aggressive EE [without building Electrification]	Aggressive retrofit rate with high energy efficiency	Aggressive Electrification with total electricity demand in 2050 ~125,000 GWh	Same as SB 350 Scenarios
Baseline: Aggressive EE with Electrification ("Aggressive EE_Electrif.")	Aggressive retrofit rate with high energy efficiency and building electrification	Aggressive Electrification with total electricity demand in 2050 ~125,000 GWh	Same as SB 350 + Industry Electrification

Figures 6.1 and 6.2 show total annual demands for the WECC and California in the periods simulated with SWITCH. In addition to the five load scenarios described in Table 6.1, we also have modeled three load projections from climate change models. From that modeling we have selected "Aggressive EE_Electrif" for the Baseline scenario.

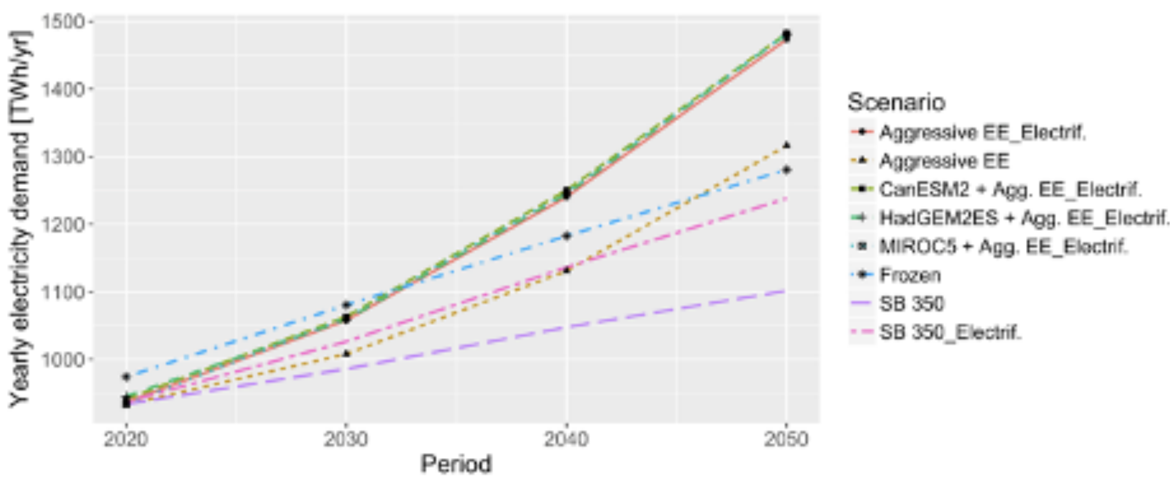

Figure 6. 1 Electricity demand scenarios for the WECC

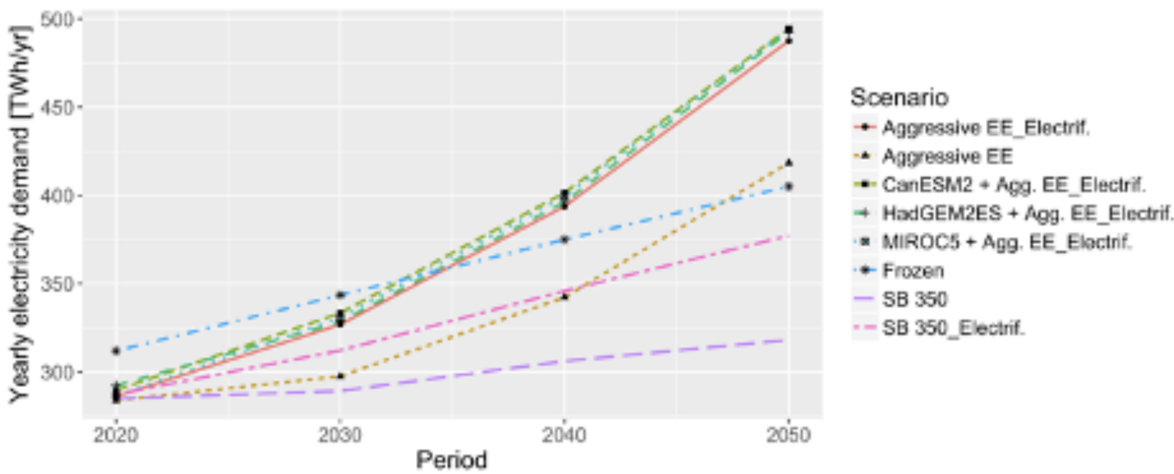

Figure 6. 2 Electricity demand scenarios for California

6.2 Loads in RESOLVE

The loads used in the RESOLVE RSP are vetted through the CEC's IEPR process. The RSP definition for RESOLVE includes load profiles for all zones. The current IEPR process is identifying updates to the projected load profiles. For our baseline we will use the loads that are included in the current RSP or we may use any update that E3 includes in their release of the updated version of RESOLVE.

A new IEPR review is ongoing. As the results of IEPR become available, we anticipate adopting them if it is not disruptive to our study at that point.

Recent developments after the 2018 IEPR that we wish to consider in selecting the load include the Governor's executive order to stop sales of internal combustion-engine driven cars by 2035 and increased investment in hydrogen.

Governor Newsom's Executive Order N-79-20 in September 2020 is anticipated to accelerate the adoption of electric vehicles beyond what was envisioned in the 2018 IEPR. We will adjust the baseline accordingly.

Increased investment in green hydrogen also motivates us to update the hydrogen electrolysis scenario. As part of a stimulus package to accelerate green hydrogen in Europe, "the European Commission (EC) published a plan to accelerate renewable hydrogen development, targeting the deployment of 6 GW of renewable hydrogen electrolysers by 2024 and 40 GW by 2030."[6] Even if they fall short of this target, California's abundant and low-cost solar electricity is likely to enable electrolyzer installations to begin increasing on a time frame that will likely follow Europe by about 5 years. We find that the High Hydrogen scenario provided in the RESOLVE Scenario Tool will provide a reasonable baseline if the 2020 data are set to zero.

We anticipate that adjusting the load profile to reflect adoption of new technologies will have a large effect on the use of long-duration storage. In particular, the following will have a large effect:

[6] https://www.reutersevents.com/renewables/wind/europe-must-double-green-hydrogen-projects-hit-target

• As more electric vehicles are procured, if these are charged during the day (when solar electricity is likely to be abundant) they effectively act as long-duration storage. If, instead, they are charged at night (when the sun isn't shining) they may increase use of long-duration storage.

• Hydrogen electrolysis may be implemented as a consistent load, or it may be controlled to use surplus electricity and turn off in times of electricity shortage, affecting the use of long-duration storage.

• Today, some loads are intentionally shifted to nighttime to use lower-cost electricity. If those loads are shifted to daytime in the future, this may reduce the use of long-duration storage.

7. Policy actions

This project is driven primarily by the California laws and Executive orders that direct the state to transition to a clean energy system. These policies include:

Senate Bill No. 32, Chapter 249 (Sept. 8, 2016) charges the State Air Resources Board with monitoring and regulating sources of emissions of greenhouse gases to reduce these "to 40% below the 1990 level by 2030."[7]

Assembly Bill No. 197, Chapter 250 (Sept. 8, 2016) requires the State Air Resources Board "to approve a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions level in 1990 to be achieved by 2020. … Transparency and accountability also are essential to ensuring the state's actions are done in an equitable fashion that is protective and mindful of the effects on the state's most disadvantaged communities." [8]

Senate Bill No. 100, Chapter 312 (Sept. 10, 2018) Created the California Renewables Portfolio Standard Program: emissions of greenhouse gases, which "requires the PUC to establish a renewables portfolio standard requiring all retail sellers, as defined, to procure a minimum quantity of electricity products from eligible renewable energy resources, as defined, so that the total kilowatthours of those products sold to their retail end-use customers achieve 25% of retail sales by December 31, 2016, 33% by December 31, 2020, 40% by December 31, 2024, 45% by December 31, 2027, and 50% by December 31, 2030. … it is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045. The bill would require that the achievement of this policy for California not increase carbon emissions elsewhere in the western grid and that the achievement not allow resource shuffling."[9]

Executive Order B-55-18 to Achieve Carbon Neutrality by Edmund Brown, Governor of the State of California, ordered that "A new statewide goal is established to achieve carbon neutrality as soon as possible, and no later than 2045, and achieve and maintain net negative emissions thereafter. This goal is in addition to the existing statewide targets of reducing greenhouse gas emissions."[10]

Executive Order N-79-20 by Gavin Newsom, Governor of the State of California, ordered that "It shall be a goal of the State that 100 percent of in-state sales of new passenger cars and trucks will be zero-emission by 2035. It shall be a further goal of the State that 100 percent of medium-

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[7] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32
[8] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160AB197
[9] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100
[10] https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf

and heavy-duty vehicles in the State be zero-emission by 2045 for all operations where feasible and by 2035 for drayage trucks."[11]

This project is largely focused on the above laws that require stepwise transition to 100% of retail sales of electricity to be from renewable or zero-carbon sources. Executive Order B-55-18 sets a goal that will be much more difficult for the state to reach. The state of California has already made substantial progress decreasing the electrical grid's carbon emissions. Today, the largest source of GHG emissions is from the transportation sector. Thus, Executive Order N-79-20 was a key action to take in order to meet the goal set by Executive Order B-55-28. The policies are interrelated. The transition to electric vehicles (EVs) will almost certainly increase electricity consumption in California. Perhaps more importantly for this project, it provides an opportunity to use the EVs to assist in balancing supply and demand as the grid is transitioned to zero-carbon sources, affecting the need for storage.

There has been much talk of using the batteries in EVs to help power the grid in a "vehicle-to-grid" concept. This would require that EVs be charged at times when electricity is abundant and be plugged in and available for discharge at times when electricity is scarce. Currently, the utilities offer EV charging rates for customers to charge their vehicles during the night. If the grid is powered mostly by solar energy, vehicles will need to be charged during the day unless they will be charged from storage. Thus, investment in daytime charging infrastructure should be a priority to enable EVs to act as an asset to the grid. **Investigating the effects of daytime vs nighttime charging of EVs will be a priority for us to explore. We will add EV charging to our baseline inputs in both models.**

We don't know what new policies will be introduced in the coming years, but a second important policy change toward carbon neutrality for all sectors would be the adoption of heat pumps, enabling heating from zero-carbon electricity. Heat pumps can require substantial energy at times and on days when neither solar nor wind energy is reliable, increasing the importance of storage. **The effect of heat pump adoption will be a significant challenge to the grid and will be a second priority for us to explore**. An alternative scenario may be the use of hydrogen rather than heat pumps for heating. Because the choice between heat pumps and hydrogen for heating is not obvious, we will not add heat pumps to our baseline scenario.

[11] https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf

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