SOUTHERN CALIFORNIA EDISON
Energy for What's Ahead®

PATHWAY 2045

Appendices

November 2019

Contents

Appendix A: Methodology

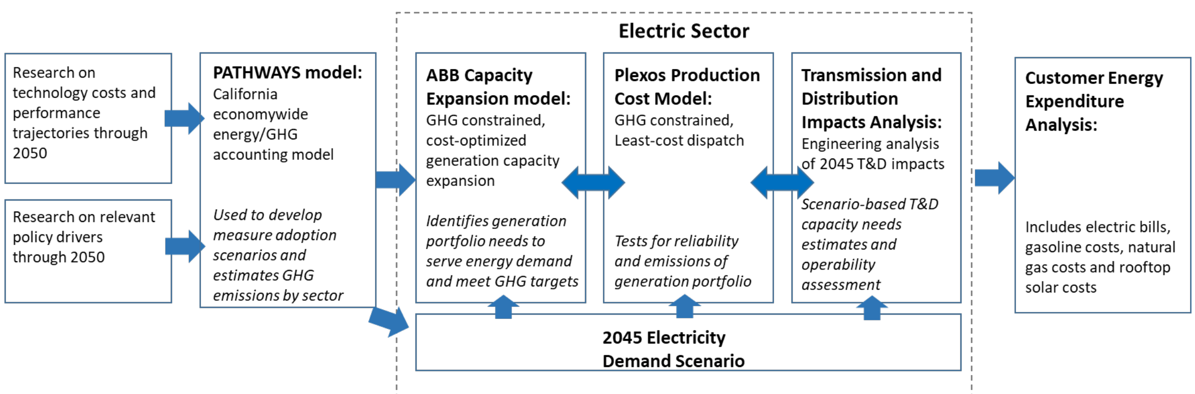
1. Overall Analysis Approach

The Pathway 2045 analysis was designed to update Southern California Edison's 2030 Clean Power and Electrification Pathway and extend the updated results to 2050. The analysis began with research on technology costs, performance trajectories and policy drivers through 2050 (Figure 1).

This research was used to update the 2030 Pathway and extend it to 2050 using an economywide greenhouse gas (GHG) accounting model:

1. The results provided a 2045 electric sector GHG target that was used as a constraint in the capacity expansion modeling that optimized the electric sector resource buildout in 2045.
2. These 2045 resource portfolios were put into a production cost simulation model to test reliability and ensure GHG emissions targets were achieved.
3. The resulting resource portfolios and production cost simulation results were used to estimate additional transmission and distribution capacity and operability needs.
4. The costs of generation, transmission and distribution development were then converted into an SCE revenue requirement that was then used to estimate average SCE residential electric bills. Total energy costs, including gasoline, natural gas and electricity, were estimated to understand the impact of the 2045 Pathway on residential customers.

Figure 1: Pathway 2045 Analysis Approach



2. Economywide GHG Analysis

Pathway 2045 used PATHWAYS, an economy-wide energy supply, demand, and GHG emissions accounting tool developed by Energy + Environmental Economics (E3),[i] to conduct economywide GHG emissions modeling. PATHWAYS is used to evaluate long-term decarbonization plans to support GHG mitigation planning. The model tracks GHG emissions from California's supply and demand side choices and was used by the California Air Resources Board (CARB) to develop California's 2017 Climate Change Scoping Plan.

As a starting point, the analysis uses the 2017 Scoping Plan[ii], with new actions and policies that have occurred since its publication in November 2017 to model an economywide, business-as-usual scenario that reflects current legislative and regulatory policies that impact GHG emissions (Current Policy scenario). The Current Policy scenario falls short of achieving California's 2030 GHG compliance target of 260 MMT emissions by 49 MMT.

The analysis selected GHG mitigation measures based on key criteria and modeled selected measures in PATHWAYS to meet 260 MMT and to reach California's 2050 GHG goal of 86 MMT. In particular, Pathway 2045 looked at technologies that will continue to support GHG emissions reductions beyond 2030 and help California achieve its 2050 goal, i.e., technologies with a low risk of stranded investment by 2050.

Criteria included:

- Feasibility of measure adoption;
- Relative marginal abatement cost as compared with other alternatives;
- Relative GHG abatement potential as compared with other alternatives;
- Trends in market movement/adoption; and
- Consistency with meeting the state's 2050 GHG emissions goal.

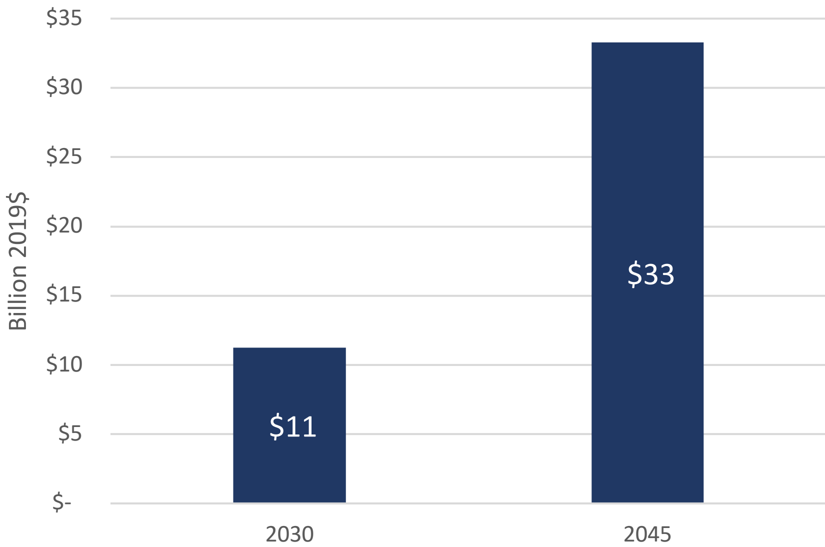
The tables below summarize model results of the forecasted adoption measures of low-carbon technology and fuels. Table 1 contains the 2045 and 2050 results; 2045 results represent the adoption levels needed in that year (determined from the PATHWAYS model) to feasibly meet the 2050 decarbonization goal.

Table 1: Key 2045 and 2050 Pathway Results

Measure	2030 Pathway Results	2045 Pathway Results	2050 Pathway Results
Carbon-free electricity	80% carbon-free 30 MMT	100% carbon-free 10 MMT	100% carbon-free 9 MMT
Light-duty vehicles	• 7.5M EVs (25% of stock) •	• EVs = 75% of total stock • Hydrogen vehicles= 13% of total stock	• EVs = 82% of total stock • Hydrogen vehicles= 15% of total stock
Medium-duty vehicles	• 280K EVs (23% of stock)	• EVs = 67% of total stock • Hydrogen vehicles = 5% of total stock	• EVs = 75% of total stock • Hydrogen vehicles = 9% of total stock
Heavy-duty vehicles	• 23K EVs (6% of stock)	• EVs = 38% of total stock • Hydrogen vehicles = 20% of total stock	• EVs = 48% of total stock • Hydrogen vehicles = 27% of total stock
Buses	• 36K EVs (50% of stock)	• EVs = 85% of total stock	• EVs = 89% of total stock
Residential space heating	31% electric	75% electric	85% electric
Residential water heating	31% electric	81% electric	88% electric
Commercial space heating	36% electric	73% electric	83% electric
Commercial water heating	7% electric	49% electric	60% electric
Industrial electrification		~25%	~25%
Rail electrification		~75%	~75%
Reductions in methane (percent reduction relative to 2015)	30%	39%	42%
Reduction in F-gases (percent reduction relative to 2015)	43%	46%	48%
Petroleum industry demand reduction	19%	36%	41%
Biomethane: Percent of total pipeline gas	5%	39%	51%
Pipeline Hydrogen: Percent of total pipeline gas		2%	4%

The incremental cost of the 2030 and 2045 Pathway relative to the Current Policy Scenario is shown in Figure 2.

Figure 2: Incremental 2045 Pathway Costs Relative to a Current Policy Scenario



These values represent the additional statewide costs needed to reach California's 2030 and 2045 Pathway goals relative to current legislation and natural adoption (Current Policy scenario). This cost assessment includes the annualized capital costs and the expected fuel costs net of savings incurred from all GHG abatement mechanisms chosen. It does not include any societal benefits from reduced emissions.

3. 2045 Electricity Demand

For load and distributed energy resource (DER) assumptions, SCE leveraged its latest corporate retail sales forecast (2018 Q4 Sales Forecast) and adjusted for high levels of transportation electrification (TE) and building electrification (BE) that are required to help achieve the state's GHG reduction goal by 2050. TE vehicle adoption levels from SCE's PATHWAYS analysis through 2050 were used to project TE load based on Vehicle Miles Traveled (VMT) assumptions from annual adoption estimates from SCE's PATHWAYS analysis through 2050. Energy efficiency (EE) assumptions are from the California Energy Commission's (CEC) 2017 iii. Behind-the-meter (BTM) solar (PV) forecast is based on SCE's internally developed bass diffusion adoption model and extended to 2045. Unique (internally developed) hourly load shapes are applied to each DER annual forecast to generate the hourly load modifier forecast. The hourly load modifiers are then integrated with the hourly consumption forecast to form the updated 2045 hourly load forecast. Management of "flexible" load was also assumed in the 2045 demand forecast including up to 10% of building loads and 50% of light-duty electric vehicle charging.

4. Capacity Expansion Modeling

Overview

SCE used a capacity expansion model to select an optimal generation resource portfolio. ABB's Capacity Expansion (ABB CE) is a mathematical optimization model that identifies the least-cost resources that meet the demand profile while attaining environmental goals, such as renewable energy targets and carbon emission constraints. Other major constraints enforced in ABB CE include transmission and import/export limits, planning reserve margin and energy balance requirements. In addition, ABB CE co-optimizes the investment, dispatch and retirement for various generation resources. ABB CE is a commercially available, long-term resource planning tool developed by ABB Enterprise Software Company. SCE selected ABB CE for the full set of functionalities it provides, including:

- Battery storage and pumped hydro storage models
- Differentiated environmental goals (e.g. emission constraint and renewable generation target)
- Full 8760 hours-per-year input
- Analyzes every year in a planning horizon, rather than a sample of modeled years

The ABB CE model requires input data about (a) proposed clean energy resources, (b) proposed clean energy costs, (c) existing clean and fossil fuel resources, (d) fuel costs, (e) environmental goals and (f) transmission constraints:

(a) For estimates of proposed clean energy resources, SCE relies on the 2017-2018 Integrated Resource Planning Proceeding data found in the CPUC's RESOLVE model (RESOLVE17-18).[iv] Those estimates, in turn, refer to data developed by Black & Veach.[v] Resource potential estimates reflect what could realistically be permitted and eventually built throughout the state. SCE used the same land use screen as the CPUC's 2017-2018 Preferred System Plan.

(b) The cost of renewable resources and battery energy storage was derived from National Renewable Energy Laboratory (NREL)'s 2018 Annual Technology Baseline.[vi] Calculations from RESOLVE17-18 were used for pumped storage costs, which were based on Lazard's Levelized Cost of Storage 2.0 study.[vii]

(c) Data describing the pre-existing renewable generation resources were derived from the CPUC and CAISO datasets. These data were aggregated in RESOLVE17-18 but refer principally to the CPUC IOU Contract Database and the CEC POU Contract Report.[viii] SCE developed the outlook of pre-existing fossil fuel generation based on the CAISO Master Control Area Generating Capability List.[ix]

(d) The natural gas fuel cost and Western Climate Initiative carbon price came from IHS Markit's Reference Case scenario planning forecasts[x]. The IHS Markit Reference Case, known as Rivalry, describes a future of evolutionary change characterized by intense competition among energy sources.

(e) California's power sector environmental goals were represented in two ways in the ABB CE modeling. First, a carbon emission target of 10MMT in 2045 for the California power sector was an input from the PATHWAYS economywide GHG modeling. The corresponding

GHG emission target for the CAISO system was 8.1 MMT. Secondly, the Senate Bill 100 goal of 100% clean energy for retail sales by 2045 was implemented as a Zero Carbon Portfolio target.

(f) For the Solar Heavy scenario, SCE limited import capability to around 10,000 MW to reflect the CASIO simultaneous maximum import capability based on RESOLVE17-18. In the Balanced scenario, additional import capability is available with a cost adder. In the Balanced scenario, SCE also added transmission costs for incremental solar facilities from the full capacity deliverability status (FCDS) costs in the RESOLVE17-18 data. Each solar resource is matched to a Competitive Renewable Energy Zone, which varies in cost by location.[xi]

Gas Retirement Assumptions

As noted earlier, the capacity expansion software can model generation retirements. We assumed that all natural-gas resources could be considered for retirement when optimizing the resource buildout to meet the load and other constraints. In the capacity expansion software, the natural gas generation was subjected to an O&M cost of $50/kW-yr[xii]. Combining with a systemwide annual GHG emission constraint, this cost set a hurdle where the optimization retained natural gas resources if deemed feasible and more economic than other resources. To simplify the capacity expansion model, natural gas resources were aggregated into various large groups as defined by the CAISO Capacity Master File and by average heat rate. Thus, when the optimization determined the amount of natural gas to retain on the system, the results indicated the total capacity retained, not specific units. For both scenarios, the retained natural gas resources were from the most efficient resources, combined cycle combustion turbines (CCGT). Other categories of natural gas resources, CHP, combustion turbines and less efficient combined cycle combustion turbines were retired by the model.

Based on the results of the capacity expansion model, SCE used a simplified methodology to translate the aggregated result to specific units. The first step was to identify if the CCGT is part of an LCR area. If it is an LCR resource, it was retained. The total capacity from this first step did not meet the total amount of capacity from the capacity expansion results. To reach the amount of retained generation, a second step was taken, where system CCGTs were selected to reach the required level. The system CCGTs were randomly selected from PG&E and SDG&E's territory. System CCGTs in SCE territory were excluded to incorporate additional renewables within SCE's territory before requiring transmission upgrades. The resulting retained CCGTs were used in both the production cost modeling and T&D grid impact studies.

5. Production Cost Simulation

Production cost simulation is used to dispatch generation resources at the least cost to meet the demand and ancillary service requirements of the system on an hourly basis while satisfying all the generator operational constraints, transmission constraints and other system reliability requirements. Ancillary services, such as operating reserves and frequency response, are necessary tools managed by the CAISO to ensure operational reliability and stability of the power system. The production cost simulation assesses the operational feasibility of resource portfolios in a power system by considering detailed generator characteristics and ramping capabilities, while balancing load on an hourly basis.

SCE uses PLEXOS[xiii], a commercial software program with a mixed integer programming optimization engine, to perform production cost simulations for the system and mimic the CAISO day-ahead market operations. PLEXOS co-optimizes energy and ancillary services and generates the commitment and dispatch of available generation resources to meet demand and reserve requirements at the least cost, subject to transmission and individual generation resource constraints. SCE's PLEXOS model used for this 2045 analysis is a CAISO-only, zonal model. The resource assumption is largely consistent with the CAISO capacity master file and the network is based on the CAISO published full network model, and no transmission constraints are enforced for this study.

Production cost simulations were preformed to validate the operability and performance of the 2045 resource portfolios selected by ABB CE for the CAISO system. The operability is evaluated by checking if the annual GHG constraint and the hourly energy/ancillary requirement can be met. If the simulation results are infeasible, adjustments of the buildout from capacity expansion are made in the production cost simulation model. An iterative process is performed until a feasible solution is achieved to ensure that the GHG emission target and operational requirements are met.

6. Transmission and Distribution Impact

An analysis was performed to determine the incremental grid infrastructure and resulting cost estimate required to reliably serve two 2045 load and resource scenarios. The analysis examined the grid from six perspectives to cover different voltage levels and address specific system needs.

1. **Distribution** – SCE's distribution system with voltages ranging from 2.4 kV to 33 kV
2. **Subtransmission** – Primarily 66 kV and 115 kV for SCE and moves power between the transmission and distribution systems
3. **Local Capacity Areas** – CAISO defined portions of the grid that require a specific amount of resources to maintain reliability.
4. **CAISO Generation Interconnection** – Grid infrastructure required to interconnect and integrate resources located on the transmission system.
5. **CAISO Imports** – Transmission infrastructure required to move out of state power into the CAISO.
6. **Inertia** – Determine if electric system is reliable at low inertia levels

Studies 1, 2 and 3 focused only within SCE's service area as our knowledge and experience are insufficient to perform these studies for other service areas. Studies 4, 5 and 6 examined the electric system at the CAISO level as Western Electricity Coordinating Council models are available to assess this portion of the grid. However, the lack of familiarity with non-SCE service areas likely limited the precision of these study results. Study 6 focused on assessing the reliability impact of losing traditional gas resources and increasing renewable resources rather than identifying specific grid infrastructure upgrades.

SCE annually assesses its electric system looking out 10 years to determine if grid upgrades are required. SCE's most recent grid planning assessments were completed in late 2018 and 2019. The 10th year out case from these annual assessments are the starting points from which 2045 scenarios were modeled. Cost estimates presented in this section of the appendix for studies 1 through 5 are incremental to this 10th year.

The studies were performed in parallel within each sub-system. The distribution, subtransmission and CAISO sub-systems did not incorporate identified upgrades required within other sub-systems. However, coordination was required between studies 3, 4 and 5 to account for power flowing from one part of the CAISO grid to another and not double count required upgrades. For example, imports into CAISO can increase power flows into in-state renewable areas and integrating new renewables within California can increase flows into local capacity areas. This interaction between studies 3, 4 and 5 means the upgrades identified for Generation Interconnections are not necessarily exclusive for that need as imports may also utilize the same facilities.

The table below provides cost estimates of projected upgrades for each system need associated with the Solar Heavy and Balanced scenarios:

Table 2: Cost Estimate ($ billions)

System	Scope	Solar Heavy Scenario	Balanced Scenario
Distribution	SCE	$4	$4
Subtransmission	SCE	$5	$5
Local Capacity Areas	SCE	$5	$5
Generation Interconnection	CAISO	$10	$6
Imports	CAISO	$13	$37

Both 2045 scenarios contained a significant amount of energy storage to shift solar energy to evening and nighttime hours to serve forecasted load. The cost of this energy storage is already accounted as a resource cost but can be utilized to reduce or eliminate grid infrastructure upgrades. Each study first identified the traditional grid upgrades required and then determined the amount of energy storage that can offset the grid upgrades. Energy storage locations that were most efficient in reducing grid upgrades were selected until the energy storage available as part of the resource portfolio was exhausted. The table above reflects the cost reductions achieved from deploying energy storage capacity to mitigate grid upgrades.

SCE Distribution

Study Parameters:

A distribution level study methodology was developed to identify the impacts of increased load and DERs on SCE's distribution system with voltages ranging from 2.4 kV to 33 kV. The study analyzed coincidental hourly loading projections at each distribution circuit and substation against typical load limit criteria and guidelines to identify two possible overload conditions:

1. Overload that is driven by high load conditions (current flowing from the grid to distribution customers) or
2. Overload that is driven by reverse power flow due to Distributed Energy Resources (DER) (current flowing from distribution-connected DERs to the grid).

To accomplish this, the coincidental annual loading profiles for each distribution circuit and distribution substation were reviewed to identify the critical points that result in violations of the conditions described above.

Study Limitations:

Overload Study

The study methodology did not include detailed power load flow, short circuit duty impacts, protection scheme evaluation or duct bank analyses. Performing these additional analyses will likely identify a need for additional projects to mitigate low- or high-voltage conditions, conductor thermal loading mitigations, infrastructure reconfiguration and additional protection equipment. Similarly, no detailed review of existing infrastructure conditions and capabilities was completed, which may result in some of the identified upgrades not being executable due to existing limitations and thus more expensive solutions may be required. For example, if a capacity addition was identified at a substation that does not have enough space for expansion and additional adjacent land cannot be acquired, a new distribution substation may be required in the area.

Energy Storage Study

When estimating required charging capacity, certain potential limitations, such as duct bank loading, were not considered. Thus, the results identified during the energy storage mitigation phase of the study reflect a number of projects that may be mitigated but could be reduced after more detailed analysis.

Study Criteria Development

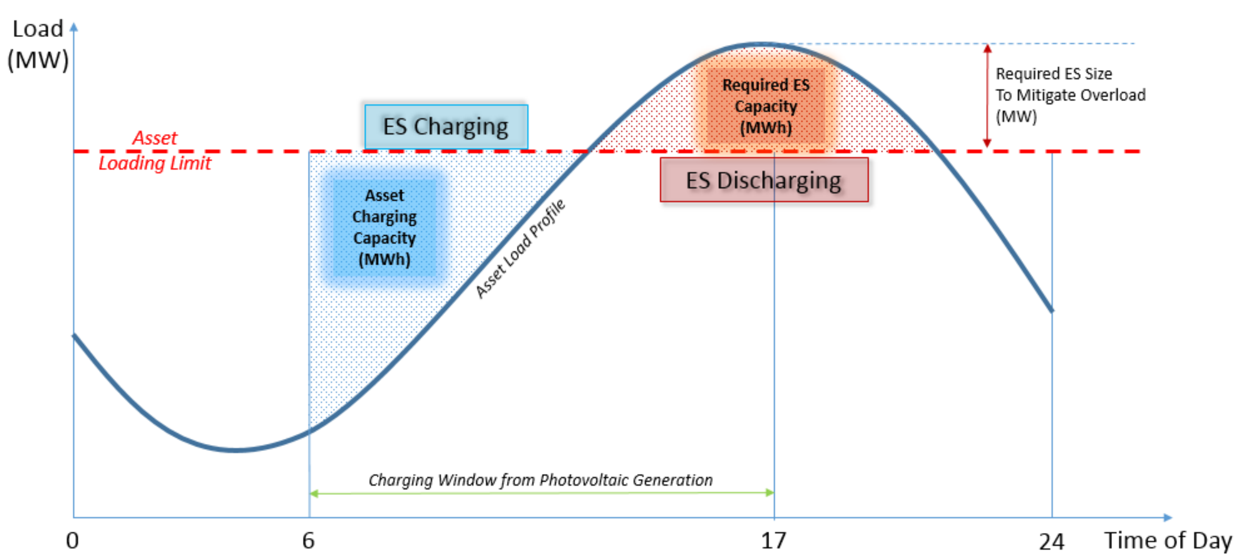
The criteria for the study was defined to identify required solutions in the most economical manner, starting from the no-cost solutions, such as load transfers between existing infrastructure to more expensive solutions such as infrastructure upgrades or construction of new infrastructure. If the projected overload exceeded the feasible no-cost solution, the criteria would first identify the possible smaller scale upgrades to maximize capacity of the existing infrastructure. The smaller scale upgrades include, but are not limited to, construction of additional ties between distribution circuits or adding additional transformation to existing substations up to ultimate build-out per SCE construction standards. If the projected overload could not be mitigated with the no-cost solutions or smaller-scale upgrade, then the required additional infrastructure is identified, such as new distribution circuits or distribution substations.

Additional criteria were defined for 4 kV systems and followed the same methodology as described in the 2021 General Rate Case. The 4 kV systems are generally very limited in their ability of being upgraded when the load is projected to exceed available capacity, and thus cutover of 4 kV infrastructure to a higher voltage was assumed to be the preferred method of addressing projected overloads on 4 kV systems.

Meeting Infrastructure Capacity Needs With Non-Wires Alternatives

Once all the required upgrades were identified, each one was evaluated for the possibility of mitigation of the projected overload with energy storage (ES). To do that, the 24-hour power demand profile during which the overload was projected to occur was analyzed. For the ES solution to mitigate the projected overload, there must be adequate charging capacity on the distribution asset, such as distribution circuit or distribution substation, in need of mitigation. As shown in Figure 3, the charging capacity must be sufficiently larger than required ES capacity in order to reduce the loading profile below the thermal overload threshold. The charging capacity of the asset was estimated based on maximum asset loading limitation, projected loading profile, charging window from photovoltaic generation and typical ES losses. The charging window is representative of solar availability and the storage charge/discharge behavior required to balance system load and resources across the entire day.

Figure 3: Overload Mitigation with Energy Storage



Cost Estimation

Multiple unit costs were developed to account for each of the identified upgrades to arrive at a total cost estimate for the distribution level study. Depending on the type of identified upgrade, either similar historical completed projects from 2014-2018 or currently pending similar type projects were utilized in developing of those unit costs.

Study Observations

The 2045 forecast and results of the study were reviewed to identify key takeaways:

1. It was observed that the overall forecasted distribution system peak was projected to occur around 8 p.m. The peak in the later hour of the day indicates that the PV systems will have minimal output and thus is naturally limited in supporting distribution system peak reduction without additional resources, such as energy storage.

2. The forecast indicated that TE is the largest load growth component contributing to the increase of the projected distribution system peak. The load from TE is expected to follow Time-of-Use (TOU) rates and forecasted to peak during the lowest energy rates. Being the largest contributing factor to the overall load growth and having TE peak when other loads are still high drives the overall distribution system peak increase. Adjustment of TOU rate schedule may help with incentivizing shift of TE load to a different hour of the day, when other types of load are not as high, and thus reduction of the distribution system peak.

3. BE is the second-largest load growth component based on the non-coincidental magnitude. However, review of the coincidental annual system load profile indicated that Building Electrification is expected to peak during cooler seasons and only contributes approximately 55% of its magnitude during the projected distribution system peak.

4. BTM energy storage is also expected to follow TOU rates allowing customers to minimize their demand during peak energy rates. Similarly, adjustment of TOU rate schedule may help with incentivizing shift of BTM energy storage peak shaving and thus help with reduction of the distribution system peak.

5. The forecast indicated that factors contributing to load increase, such as TE, BE and traditional load growth are projected to be significantly higher than the factors that reduce load such as BTM Photovoltaics, other customer-owned generation, energy efficiency and BTM energy storage. This resulted in the majority of identified required distribution system upgrades to be caused by the factor that increase load with minimum upgrades caused by forecasted DER adoption.

6. Detailed analyses of daily load profiles of overloaded assets for the possibility of the overloads being mitigated by the stand-alone energy storage indicated that the charging capacity of the asset is significantly reduced by the constraint of photovoltaic generator energy output used to recharge energy storage. Cascading transfer of energy from bulk-connected energy storage to distribution-connected energy storage, during periods when photovoltaic generations is not generating any energy, may allow more utilization of distribution asset's charging capacity and thus possibility additional overloads being mitigated with stand-alone energy storage.

SCE Subtransmission

SCE's subtransmission system is comprised of a mixture of 66 kV and 115 kV load serving substations (A-Stations) for a total of 46 A-Stations within the SCE service area. To understand the system limitations and identify physical upgrades needed to accommodate expected 2045 conditions, power flow studies were performed on 21 subtransmission systems. The 8760 load profile of the projected load growth for all the distributions stations in 2045 was used to create the power flow base cases. Both wires and energy storage solutions were explored.

Methodology

There were two main focuses on identifying the upgrades:

i. Determine if the existing and already planned transformer bank capacity (A-Bank) is adequate for 2045; and

ii. Determine if the existing and already planned subtransmission line capacity is adequate to support projected 2045 conditions under normal and contingency conditions.

For systems that did not have adequate A-Bank capacity with the current configuration, A-Bank capacity was added up to the SCE standard four A-banks/substation. The addition of the fourth A-bank would require the splitting of the 66 kV bus in order to keep short circuit duty (SCD) within allowable limits. However, if the A-station was already built-out with four A-banks, a new A-Station was proposed as a means of moving some of the load into a new system. Additionally, any identified overloaded lines including underground cables were assumed to be reconductored to the highest-rated conductor and that existing infrastructure would be insufficient to support the new conductor. The remaining 25 systems were assessed using a spreadsheet analysis that determined if the existing A-bank and line rating with the load increase would require additional upgrades. In order to develop a cost for the upgrades identified, the published SCE unit cost was used to develop an overall cost for the physical upgrades for the entire SCE subtransmission system.

Following completion of the capacity limitations and definition of physical upgrades ("wires upgrades") to increase capacity where needed, the evaluation considered the use of energy storage as an alternative to the defined wires upgrades. This study used the hourly load data and took the highest coincident load at each A-station to create a base case and determine the overloads. Once the energy storage capacity was optimized to mitigate the identified overloads, the ability of the energy storage to discharge for the duration of the overload was determined. If the duration of the required discharge was greater than the time available for charge, it was then determined that energy storage could not be an alternative to the wires solution for the system. It was assumed that the energy storage would only be able to charge from the available PV production.

Out of Scope

The following three significant items were not included in the subtransmission level evaluation:

1. Need for potential circuit breaker upgrades were not defined as SCD analyses were not performed
2. Feasibility to license, engineer, and construct new A-stations, new subtransmission lines and upgrades to existing facilities.
3. Optimized mix of wires and storage to mitigate issues was not derived

Results and Observations

Key results and observations on the subtransmission level are as follows:

1. Most subtransmission systems did not have adequate capacity to serve forecasted load in 2045.
2. Total wires cost to reinforce subtransmission system to accommodate 2045 loads was $5 billion
3. In most cases, the subtransmission system could not use energy storage as a wires alternative due to charging requirements

SCE Local Capacity Areas

The California Independent System Operator (CAISO) annually conducts a Local Capacity Technical Study, which identifies the minimum resource capacity needed in each local area to meet established reliability criteria. Load serving entities use these study results to develop resource adequacy plans and demonstrate they have procured the necessary capacity to reliably serve their customers.

SCE's 2045 Local Capacity Requirements (LCR) analysis explored a resource and load portfolio forecasted for the year 2045 and its impact to reliably serving SCE's local capacity areas. The results of this analysis highlighted transmission system issues and evaluated wires mitigations including the feasibility of local energy storage as an alternative to wire upgrades.

Inputs, Assumptions, and Methodology

Table 3: System Assumptions, Power Flow and Post-transient Analysis

Input	How Incorporated into Study:
System Assumptions:	
Transmission System Configuration	The starting system model was a 2029 WECC base case, which modeled the existing Western Interconnection transmission system as well as projects expected to be operational on or before the year 2029.
Load Forecast	The CAISO-wide summer peak load was forecasted to occur on September 7, 2045 at hour-ending (HE) 21. This system-wide peak load was disaggregated and allocated to the substation loads modeled in the 2029 WECC base case. These loads represented customer demand net of any distribution-connected resources downstream.

Resource Modeling and Dispatch	Existing CAISO-resources (generation and storage) expected to remain operational in 2045 were modeled as well as incremental resource capacity based upon the 2045 resource portfolio. The output of these resources was dispatched in the power flow base case in accordance with a production-cost simulation model for September 7, 2045 HE 21.
Power Flow and Post-transient Analysis:	
Software Tools	GE PSLF (Version 21) and PowerWorld Simulator (Version 21)
Contingencies	Evaluated system performance for select transmission contingencies with known reliability impacts. Contingencies include single or multiple outages of grid facilities.

Mitigation Development

In order to mitigate thermal overloads and voltage collapse, the analysis evaluated the effectiveness of transmission reinforcement ("wires") and the feasibility of energy storage as an alternative.

Table 4: Mitigation Development

Mitigation Development:	
Wires	Scoped system upgrades such as new transmission lines, substations, or reactive support devices to mitigate issues.
Wires Cost Estimates	High-level cost estimates were developed utilizing SCE 2019 Per Unit Cost Guide[xiv] as well as estimates from recent studies.
Energy Storage	As an alternative to above wires mitigation, scoped amount of energy storage resources to mitigate identified issues. This included the feasibility of charging the energy storage resources.
Daily Load Shapes	24-hour peak day load shapes for each SCE load were utilized to determine charging feasibility based upon transmission limitations (i.e. voltage stability and thermal loading limits).

Out of Scope

1. Comprehensive review of system performance and mitigation for all contingencies mandated by applicable bulk electric system standards and performance criteria (i.e. NERC TPL-001-4, WECC Regional Business Practices, CAISO Planning Standards)
2. Short Circuit Duty Analysis
3. Transient Stability Analysis
4. Feasibility to license, engineer, and construct wires upgrades and energy storage
5. Development of optimized mix of wires and storage solutions to mitigate issues, including feasibility of transferring energy from bulk-connected energy storage to local energy storage with wires upgrades.

Results and Observations

Significant load growth combined with the loss of gas plants within SCE local capacity areas resulted in voltage collapse and thermal overloads. Transmission upgrades, including numerous new 500/220 kV substations, lines, and reactive support devices were required to address.

Utilizing energy storage to offset wires upgrades required larger capacity storage units within the local area that collectively needed to discharge for longer than 4-hours to mitigate reliability issues. The time period to charge energy storage was restricted to the daylight hours when solar generation was available. This made storage as a solution largely infeasible in most areas since the transmission system was unable to charge the storage while maintaining service to load within this charging window.

CAISO Generation Interconnection

The CAISO generation interconnection study strategically placed new generation in order to approximate the costs of the necessary upgrades to safely and reliably bring these resources to utility load centers within the CAISO grid.

The study focused on hours with the greatest generation dispatch. To place the generation and approximate the necessary upgrades, a combination of G.E.'s Positive Sequence Load Flow[xv] (PSLF) Software and spreadsheet analysis was used. A PSLF 2029 Heavy Summer base case was used as a starting point and then modified as necessary to approximate 2045 CAISO grid load. The additional generation resources were then placed in the PSLF base case taking into consideration the CAISO Generation Interconnection Queue, California Energy Commission (CEC) geospatial data layers for transmission facilities, Google Earth Pro software, and the California Public Utility Commission's (CPUC) Resolve Model.

The CAISO Generation Queue[xvi] lists all CAISO generation and storage interconnection requests that have been completed, withdrawn, and which are currently in queue. Interconnection locations with high withdrawal rates were avoided and locations with currently queued and successful interconnection requests were pursued when possible. Furthermore, the CEC provides geospatial data layers for major substations[xvii] and transmission lines[xviii], and these files were used in combination with Google Earth Pro software to identify transmission facilities located outside of the SCE service territory and to determine whether these existing substations might have the space and necessary infrastructure to accommodate new generation interconnections. If a substation in the PSLF base case showed available capacity, then a desktop review using Google Earth Pro was performed to determine whether the substation had available switchrack positions to interconnect new generator tie-lines or if a substation expansion might be required. Furthermore, Google Earth Pro was also used to check if land was available for new transmission line right-of-ways (ROW) and new substation locations. As generation was added to the base case, the CPUC's Resolve Model[xix] was used as a guide for the purpose of respecting generation potential resource values for each Competitive Renewable Energy Zone (CREZ).

When generation placement triggered thermal overloads and voltage issues, with all T&D facilities in-service, upgrades were added to the PSLF base case to resolve those reliability issues. While many of the triggered upgrades were unique to this study, efforts were made to utilize previously triggered and previously proposed upgrades from the CAISO Transmission Planning Process and the CAISO Generation Interconnection Process. While contingency analysis, voltage stability, transient stability, and short circuit duty (SCD) analyses was not performed for this part of the study, generation was placed in such a manner as to allow for Remedial Action Schemes (RAS) to curtail new generation to mitigate thermal overloads and system instability issues under single and double transmission facility outages. To facilitate this N-0 approach, using RAS to mitigate outages on transmission facilities, generation was placed with the intent of respecting the CAISO's RAS tripping limitations of 1,150 MW for single contingencies and 1,400 MW for double contingencies[xx]. In addition to using RAS to mitigate expected contingency overloads, energy storage was also used to offset triggered transmission upgrades where applicable. For example, if generation placement at an existing substation triggered a new line or transformer, a check was performed to see if placing energy storage in the same location, functioning in charging mode, could absorb the new generation thereby eliminate the need for the transmission upgrade.

After all the generation in each scenario was placed and the necessary transmission upgrades and energy storage was determined, cost for the upgrades were developed by using publicly available per unit cost guides[xxi], previously identified costs from the CAISO Transmission Planning and Generation Interconnection Processes, and past completed projects that were similar in scope. Given the diverse sources for the cost estimates, the dollar years and contingency amounts for the cost estimates are not uniform.

CAISO Imports

Cost associated with bringing in out-of-state imports into the CAISO footprint starts with two pieces of data from the two scenarios. The first set of data is the maximum capacity of out-of-state resources and their approximate location. The second set of data is the simultaneous imports from the production cost modeling, which balances load and resources (imports included) for the entire year. The highest import hour for the Balanced scenario was 6:00 P.M. on December 21, 2045. The Solar Heavy scenario had multiple hours with the same highest import so the highest load hour at 7:00 A.M. on April 4, 2045 was selected.

The first set of data, the maximum capacity of out-of-state resources and its approximate locations, is first translated to out-of-state locations on a map and potential transmission routes laid out for export to CAISO. After mapping these resources, the existing transmission lines are transposed on top of potential transmission line routes and assessed for its known capacity and voltage class to be considered as part of a transmission path expansion. Using Google Maps, the transmission line lengths were approximated to determine the distances to substations located in SCE, PG&E, and SDG&E at the CAISO border (e.g., Eldorado, Colorado River, etc.).

The potential transmission lines were then appropriately sized to accommodate the out-of-state resources. Transporting out-of-state resources will use either direct current (DC) transmission and/or

500 kV alternating current (AC) transmission lines. The mix of AC and DC transmission lines will depend on the following factors; cost, least amount of total lines, distance, transmission congestion, and ability for power to flow from one place to another.

After all these considerations, the transmission lines and its associated equipment were identified to a level that an order of magnitude cost was calculated. The cost was calculated using unit cost guide published on the CAISO website for SCE, PG&E, and SDG&E. These would form the basis a state of origin integration cost estimate to bring out-of-state resources to the CAISO border.

The second set of data is used to model the highest simultaneous CAISO import for simulation in a power flow program that can calculate the voltage and power flow of the transmission system for the western half of the United States. The highest imports are then simulated for April 4, 7 A.M. for the Solar Heavy scenario and December 21, 6 P.M. for the Balanced scenario. Simulations were performed to identify transmission issues in and around the CAISO boundary. Once the problems were identified such as thermal overloads, upgrades were modeled by adding a second parallel transmission line or reconductoring to verify that the upgrades are adequate and to determine if there are any additional transmission upgrades required to meet transmission reliability criteria. This forms the basis of the dispatch cost to bring power from the border to the CAISO load centers.

The Solar Heavy scenario identified a state of origin integration cost of approximately $12.3 billion for a mix of 500 kV AC and DC transmission lines and a dispatch cost of approximately $0.3 billion for a mix of 500 kV AC transmission lines and remedial action schemes.

The Balanced scenario identified a state of origin integration cost of approximately $26.0 billion for a mix of 500 kV AC and DC transmission lines and a dispatch cost of approximately $10.6 billion for a mix of 500 kV AC transmission lines and remedial action schemes.

System Inertia

The existing electric grid has conventional synchronous machines (e.g., generators and motors) that provide rotational mass (inertia) needed to maintain system stability under abnormal system conditions. A loss of system stability could lead to uncontrolled loss of load, cascading outages, and possibly utility system blackout. The 2045 generation fleet envisions increasing the amount of inverter-based resources to allow California to move toward carbon-free resources. However, as more inverter-based resources replace synchronous generators, the available rotational mass connected to the grid is reduced, which effectively reduces the ability to maintain system stability under abnormal system conditions. To gain a better understanding of the operating conditions under which the system stability may no longer be maintained, SCE assessed the system under several low inertia conditions.

System performance was assessed at various inertia levels for the loss of the Palo Verde nuclear power plant, which is the largest Western Interconnection contingency. As the system inertia levels were varied, system performance was monitored immediately following the contingency event to determine the threshold at which system stability could not be maintained.

Inverter performance is critical to frequency control as the penetration of inverter-based resources continues to grow. Although industry approved models for inverter-based resources have the capability to provide Active Power Frequency Controls (Primary Frequency Response), this capability is not enabled because operationally the resources are dispatched to maximum capacity with no reserved capacity margin to provide the frequency response. In addition, these models lack the Fast Frequency Response (FFR) capability that provides grid frequency support like the inertia provided by synchronous generators.

During a representative spring day, April 4, 2045, the conventional synchronous resources on the system is very low at approximately 3% of the total generation dispatch. The assessment indicated unstable system performance under both 2045 scenarios well above 3%. Different inertia threshold levels were identified, which indicated the demarcation between stable and unstable system performance can vary. The difference in threshold levels was due to varying operating conditions (e.g. morning vs. evening hours, generation fleet dispatch, import level).

Current inverter modeling and data limitations among other simulation concerns means more rigorous and measured analyses will need to be performed to gain a much more accurate, deeper and broader understanding of the electric system performance under the conditions proposed for 2045. Utilities should start preparing for the future by defining grid forming capability requirements for inverter-based resources so manufactures can develop the technology to replace the support traditionally provided by synchronous machines.

CAISO Transmission and Distribution Cost Methodology

As noted earlier, the T&D cost estimates for the two scenarios, Solar Heavy and Balanced, were determined at different areas, either SCE or CAISO wide. In order to provide some context relative to the resource costs which were determined for CAISO wide, a simplified cost scaling methodology was employed. To scale the distribution and subtransmission system costs to CAISO, the SCE costs were scaled according to system peak share as indicated in Table 5. For example, the $4B in distribution costs were divided by SCE proportion of peak load of 49.8% to get the CAISO wide cost of $8B. For the Balanced scenario, the CAISO distribution cost was higher ($10B) than the Solar Heavy scenario ($8B) because there was no additional storage available from the resource buildout to offset grid investments.

Table 5: Peak Load Proportion by Investor-Owned Utility (IOU) Transmission Access Charge (TAC)

Utility	Peak Load Proportion by IOU TAC
SCE	49.8
PG&E	41.7%
SDG&E	8.5%

The local capacity area cost at the CAISO level was obtained by first determining the deficiency of any local capacity area. SCE used CAISO's 2024 LCR need analysis[xxii] to establish the capacity threshold needed to maintain local reliability. SCE then determined how much capacity was in each local capacity area using the resource buildout for each scenario. The total amount of capacity deficiency was determined from these two datasets. Since SCE retained the same amount of natural gas generation in local capacity areas, the deficiency for both scenarios in the local capacity areas did not change between scenarios. Costs were then assumed to scale according to SCE's proportion of the total capacity deficiency as indicated in Table 6. For example, the $5B in SCE local capacity areas' costs was divided by 51% to get a CAISO scaled cost of $10B.

Table 6: Percentage of Local Capacity Area Deficiency

Utility	Percentage of Local Capacity Area Deficiency
SCE	51%
PG&E	28%
SDG&E	21%

7. Energy Affordability Analysis

The energy affordability analysis is designed to capture the financial impact of a high electrification world on SCE's residential customers. The analysis represents the change in annual fuel and utility bill payments as customers switch to electricity from gasoline and natural gas. The share of wallet calculation includes annual electricity bills, rooftop solar costs, gasoline costs, and natural gas costs for an average SCE household, a non-adopter household, and an adopter household in 2019 and 2045. The major assumptions for each component are described in detail below.

Electricity Bill

In determining average residential bills for Pathway 2045, SCE used the residential revenue allocation factors from its 2018 GRC Phase 2 proceeding to determine the bundled functional revenue amount for each rate component (i.e., Distribution, Transmission, Generation, Public Purpose Programs, etc.) associated with generation, transmission, and distribution additions modeled to meet California's climate goals by 2045. The sum of the bundled functional level revenue requirements represents the total bundled revenues assigned to the bundled residential class. The sales forecast for bundled residential customers represents the year 2045, which were disaggregated into CARE and non-CARE customer groups. Once revenues for residential CARE and non-CARE customers were estimated, the residential average rates (RAR) were determined by dividing the assigned revenues by the forecasted sales. The average monthly bill was then determined by multiplying the RAR by average forecasted monthly usage.

The monthly usage for an average residential customer was estimated by dividing the total residential load in SCE's territory by the number of residential accounts, which was used as a proxy for number of households. For example, the average household has 1.89 vehicles because the total amount of energy-related technologies is spread across all SCE households. For the non-adopter energy demand, residential consumption load[1] was estimated using actual average SCE residential load in 2017. SCE

[1] Consumption load is the sum of all residential customer end use loads

believes that the average actual residential load in 2017 serves as a reasonable proxy for the non-adopter consumption load because of the limited penetration of distributed energy resources that occurred up to 2017.

For the adopter, consumption load was altered by including actual average energy efficiency reductions per household from SCE energy efficiency programs in 2018 and the output from a 4.8 kW solar system. Potential impacts of higher future energy efficiency reductions associated with SB350's targets were not considered in these projections; SCE considers this to be a conservative assumption. Then, demand was added for electric vehicles and electric building appliances. Electric vehicle demand includes both at-home and away-from-home charging and was derived by multiplying CEC's energy assumption per vehicle[xxiii] by the number of light-duty EVs forecast per household from SCE's PATHWAYS analysis. Electricity demand associated with building appliances was estimated by taking SCE's bundled load share of California building electrification demand from PATHWAYS.

A comparison of annual household energy demand, including away-from-home charging, is in Table 7. The load increase from building and transportation electrification is roughly the same as the load decrease from solar and energy efficiency, which makes the non-adopter and adopter loads about the same. The average customer's annual energy demand is slightly higher than both non-adopters and adopters in 2045 primarily because the average solar size is only 1.5 kW when spread across all customers; therefore, the average customer calculation does not include a large amount of solar power to reduce household load.

Table 7: Residential SCE Net Household Electric Demand (kWh/year)

Customer Type	2019	2045
Average Customer	6,400	8,700
Non-Adopter	7,300	7,300
Adopter	7,400	7,400

Gasoline Costs

Gasoline Price

California's gasoline price forecast is based on the future price of fossil gasoline and future price of renewable gasoline.

To determine the future fossil gasoline price, the first step was to decompose the cost components of a gallon of gasoline in California. The California Energy Commission (CEC) provides a weekly breakdown of the cost components for a gallon of gasoline in California[xxiv]. One year of weekly data from the CEC was averaged to obtain the percentages for each component. For most of the components (e.g., refinery cost and profits, state excise taxes), the component cost was either held constant, a fixed rate (e.g., $/gal), or a fixed rate tied to the total cost of a gallon of gasoline. The only two components that required further elucidation were the crude oil cost and incremental greenhouse gas cost. For the crude oil cost, the Energy Information Administration (EIA) provides future crude oil prices[xxv]. Incremental GHG costs were calculated using an internal GHG price forecast.

SCE's PATHWAYS analysis provided both the price and percentage of renewable gasoline in the final gasoline stock. For the price of renewable gasoline, the price was assumed to be the same as fossil gasoline after 2023.

Using the two price forecasts and the percentages, the final gasoline price per gallon was calculated.

Gasoline Consumption

Annual gasoline consumption is based on the number of miles each vehicle travels per year, the efficiency of the vehicles, the fuel type of each vehicle, and the number of vehicles per household. The first three assumptions were pulled from SCE's PATHWAYS analysis. The last assumption is calculated using a weighted average from U.S. Census Bureau's data to estimate 1.89 vehicles per household[xxvi]. Gasoline consumption from PHEVs is based on the energy usage by fuel type data from PATHWAYS.

Natural Gas Costs

Natural Gas Price

The California's natural gas price forecast is based on the future price of wholesale natural gas, an assumption surrounding residential revenue requirement for natural gas, GHG costs, and renewable natural gas price.

To determine the future fossil wholesale price of natural gas, historical natural gas prices for Henry Hub and California Citygate were obtained from EIA[xxvii] [xxviii]. The difference between Henry Hub and California Citygate represents the transportation cost of delivering natural gas to California. A future wholesale price at Henry Hub was also obtained from EIA[xxix]. Finally, the incremental GHG cost was determined using an internal GHG price forecast. The final future fossil wholesale natural gas price was determined using all three pieces of information.

A renewable natural gas price was obtained from the expected biomethane supply price curve developed by E3 for the CEC High Electrification study[xxx]. The percentage of fossil and renewable natural gas mix was obtained from SCE's PATHWAYS analysis.

A historical residential revenue requirement was determined by the difference of residential rate and wholesale natural gas price. The residential retail rate was obtained from EIA[xxxi]. The assumption is that the wholesale natural gas price is a pass through. Thus, any price difference between the residential retail rate and the wholesale rate of natural gas represents the money needed to keep the natural gas system operating. Historical consumption of natural gas in California was also obtained from EIA[xxxii]. Future revenue requirement was assumed to decrease in proportion to overall decrease in natural gas consumption or remained flat. By knowing the future residential natural gas consumption and the future residential revenue requirement, a $ per MMBTU (or MCF) can be calculated that represents the cost per unit of residential natural gas consumed.

With both the future wholesale price of fossil and renewable natural gas and the residential revenue requirement per unit determined, the final calculation can be made to obtain the future cost of natural gas for a residential user.

A comparison of electric, gasoline, and natural gas prices can be found in Table 8.

Natural Gas Consumption

The assumption for annual natural gas consumption for an average home comes from the CEC BE Study. Assumptions on efficiency gains from switching to electric from gas-fueled water and space heaters are from the same study. Only water and space heating were included in the analysis because these appliances represent that majority of natural gas consumption in residential households.

Table 8: Fuel Prices

	2019	2045
Electricity ($/kWh)	0.18	0.21
Gasoline ($/gallon)	3.69	4.97
Natural Gas-High ($/mmbtu)	12.47	65.60

Household Solar Costs

Solar photovoltaic costs for residential households come from IHS Markit[xxxiii]. Sensitivities performed on each of these variables led to small changes in the final share of wallet results. The average solar PV size is assumed to be 4.8 kW based on peak load demand for residential customers.

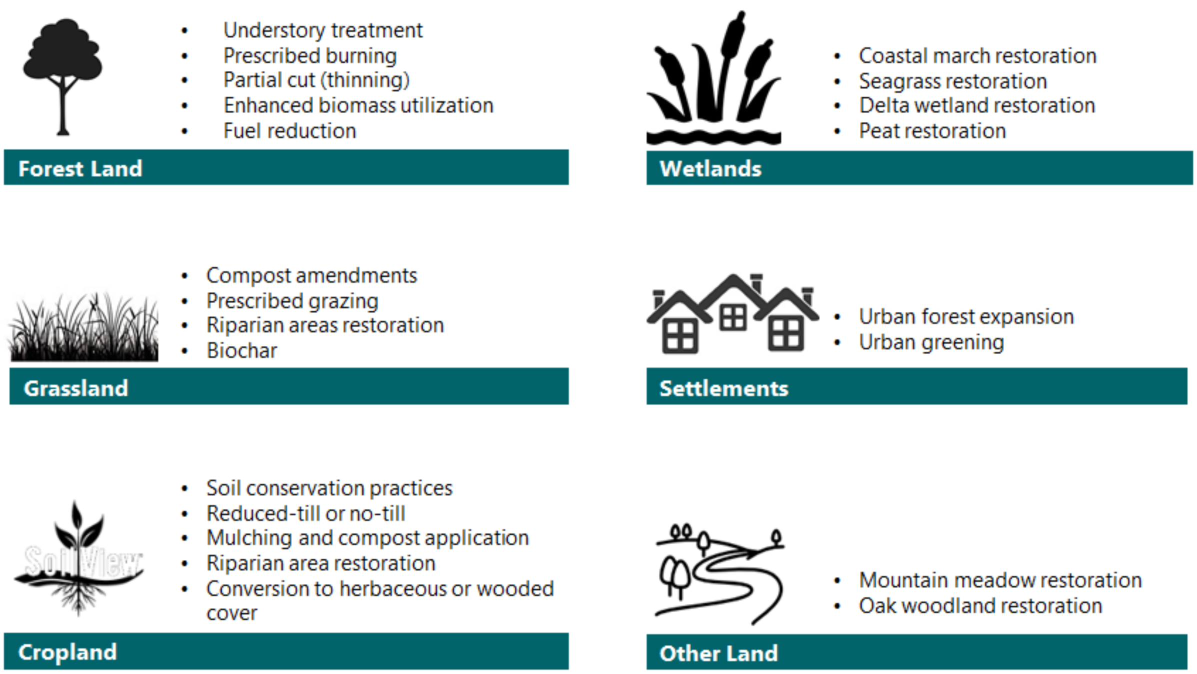
Appendix B: Additional Content

1. Reaching Carbon Neutrality

To achieve carbon neutrality, economy-wide emissions must be less than or equal to carbon emissions sequestered or removed from the atmosphere. Carbon sinks can potentially be achieved through natural and engineered carbon capture and sequestration.

Natural and working lands (NWL) is one option for carbon sequestration, which include forests, rangelands, urban green spaces, wetlands, and farms. Some strategies to increase carbon sinks through natural and working lands are shown below:

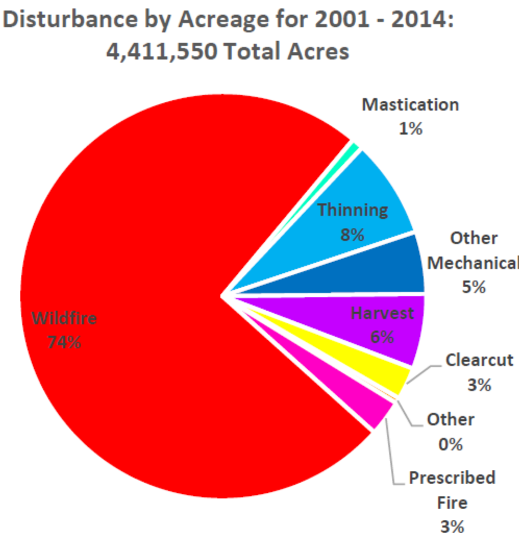
Figure 4: Example Strategies to Increase Carbon Sinks



However, currently California's NWL are net <u>emitters</u> of carbon, primarily due to wildfires (Figure 6[xxxiv]), and are projected to increase in emissions unless programs are put in place to turn NWL from sources to sinks. The U.S. Geological Survey found that the 2018 wildfire season in California is estimated to have released 68 MMT of CO_2e.[xxxv]

State action to minimize the wildfire threat, including prescribed fire, mechanical thinning, and understory treatment will restore structure and composition of ecosystems and reduce the potential for high-severity fire. These actions, in addition to natural land restoration and agricultural soil management, will enhance NWL's resilience to worsening climate impacts, sequester carbon and reduce GHGs.

Figure 5: California Land Disturbance 2001-2014



CARB's 2030 Natural and Working Land Climate Change Implementation Plan's goals are to at least double the pace and scale of state-funded restoration and management activities through 2030 and beyond, leading to a sequestration of 37 MMT CO2e by 2045.[xxxvi] However, given the need for 108 MMT CO2e in 2045, California should also explore additional sequestration opportunities, including engineered technologies.

Engineered solutions are in early stages of development and commercialization. The uncertainty in costs, sequestration potential and ecosystem feedback needs to be reduced before any given technology is deployed more fully. Substantial research and development in each category is essential to move the technology closer to large scale deployment.

Table 9: Engineered Solutions

Category	Description	Advantages	Disadvantages
Biomass + CCS	Capture carbon dioxide from the waste stream of a biomass facility and store in geological formation	- Increased job security in some areas	- Competition with natural and working lands and food - Storage not viable in all locations – extensive pipeline network needed with large-scale implementation - Water intensive
Direct Air Capture	Capture CO2 from ambient air through chemical processes with subsequent storage of CO2 in geological formations	- Little risk of release - No competition with land use	- Limited by storage (~10,000 Gton) - Energy intensive (more than bio/coal/ng + CCS) and must be powered by renewables to achieve reductions - Water intensive - Few demonstrations; very early development phase
Accelerated Weathering	Distribution of ground-up rock material over land or open ocean to accelerate the natural conversion of CO2 to alkaline bicarbonates or carbonates	- Little risk of release - No competition with land use - Counters ocean acidification	- Energy intensive - Limited by feasible rates of mineral extraction, grinding, and delivery (and associate costs in transport, disposal, and mining) - Lack of large-scale trials

			- Could cause respiratory issues with smaller particles
Ocean Alkalinity	Adds alkalinity to marine areas to locally increase the CO2 buffering capacity of the ocean	- Counters ocean acidification	- Unknown impacts on ocean systems and biodiversity (increases water pH and releases heavy metals and plant nutrients) - Saturation rate limits - Potential to trigger spontaneous carbonate precipitation
CO_2 to Durable Goods	Carbon is used to make carbonate materials, like cement-like construction materials, polymers, carbon fiber composites, graphene, carbon black, and diamonds	- Economical potential is high (i.e. construction, diamonds)	- Early stages of development
Ocean Fertilization	Add micronutrients to the ocean resulting in increased biologic production, leading to carbon fixation in sunlit ocean and subsequent sequestration in the deep ocean or sea floor sediments	- Increases available food in oceans	- Existing de facto moratorium on commercial ocean fertilization activities - Lack of large-scale trials - Decreases deep water oxygen and increases algal blooms

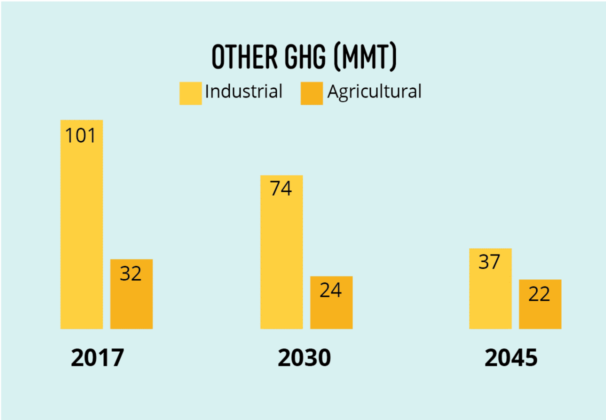
2. Other Sectors in Pathways

Industrial and agricultural sectors are comprised of varied subsectors with mixed opportunities for cost-effective efficiency gains and electrification.

Industrial

California's industrial sector is diverse comprising refineries, oil and gas extraction, cement plants, manufacturing and waste. The primary GHG emissions sources from this sector include fuel combustion in industrial processes and associated methane emissions from operations. From a political/economic standpoint, California industries may become uncompetitive if state decarbonization targets add untenable production costs relative to competitors operating in regions without significant decarbonization goals.[xxxvii]

Figure 6: GHG Emissions in California's Industrial and Agricultural Sectors



The industrial sector reduces GHG emissions from 101 MMT CO2e to 74 MMT CO2e by 2030 and to 37 MMT CO2e by 2045 through a 37% methane reduction, an 87% fluorinated gases reduction, a 36% reduction in gasoline production and approximately 25% electrification within the sector.

Table 10: Industrial Electrification by 2045

Electrification Measures	Percent Converted to Electricity: 2045
Conventional Boiler Use	5%
HVAC - Heat Pump	70%
Process Heating	2.5%
Other	25%

While the sector contributes a significant amount of GHG reductions to the economy, it also consumes the majority of the remaining carbon-based fuels.

Agriculture

GHG emissions from the agriculture sector include methane emissions from livestock (enteric fermentation[xxxviii] and manure), emissions from crop production (fertilizer use, soil preparation and disturbance, and crop residue burning), and fuel combustion from stationary agricultural activities (water pumping and processing commodities).

The agricultural sector reduces from 32 MMT CO2e to 24 MMT CO2e by 2030 (**Error! Reference source not found.**), mainly due to the Short-Lived Climate Pollutant Reduction Strategy[xxxix], and to 22 MMT CO2e by 2045 through increased efficiency improvements.

Table 11: Agricultural Efficiency Improvements by 2045

	HVAC	Motors	Refrigeration	Water Heating and Cooling	Process	Misc.
Gas	15%	15%	15%	15%	15%	15%
Electric	7%	7%	9%	6%	6%	7%

When compared to other economic sectors, the agriculture sector currently contributes the least amount of GHG emissions to the California economy. However, unlike other sectors, the agriculture sector, if managed properly, provides an opportunity to develop carbon sinks through reduced urbanization and increased cultivated and rangelands acres participating in soil conservation practices.

3. Behind the Meter Solar and Storage Adoption

SCE's internally developed bass diffusion adoption model for Behind-the-meter (BTM) solar (PV) forecast extended to 2045 yielded the following adoption results:

Table 12: Behind the Meter Solar and Storage

Load Modifier	Installed Capacity (MW)	Yearly Production/ Discharge (MWh)
Residential BTM PV	17,979	29,557,284
Residential BTM Storage	4,746	480,938
Non-residential BTM PV	11,986	19,704,856
Non-residential BTM Storage	4,746	711,510

BTM PV's energy hourly generation and BTM storage hourly charge and discharge energy are applied as load modifiers to the 2045 consumption forecast.

4. Resource Costs

SCE resource cost assumptions in the capacity expansion model are based on NREL's 2018 Annual Technology Baseline (ATB), which was the latest available at the time the research began.[xl] Fixed costs were calculated as Levelized Cost of Capacity (LCOC) in real 2019 dollars and implemented as Annual Fixed Cost in the ABB Capacity Expansion model. Variable costs from NREL 2018 ATB were escalated to real 2019 dollars and used as Variable O&M Cost. The renewable energy resource costs (i.e. solar, onshore wind, offshore wind, conventional geothermal, enhanced geothermal) used a methodology based on Levelized Cost of Energy (LCOE) and Net Capacity Factor (NCF). Battery storage costs were amortized from capital costs and weighted average cost of capital. Since pumped hydro storage was not described by NREL, data from the RESOLVE17-18 model were used directly after simply escalating to real 2019 dollars. Biomass costs from RESOLVE17-18 were also used instead of NREL's biopower estimates because the California resource potential for in state biomass represents a combination of biogas, large biomass, and distributed biomass.

Renewable Generation Cost Derivation

To accurately reflect the assumptions from NREL's cost modeling, SCE directly used LCOE and Net Capacity Factor to estimate LCOC. One change made in the NREL 2018 ATB data workbook modified the default Capital Recovery Periods from 30 years to equal the values of "Financing Lifetime" found in RESOLVE17-18. Specifically, wind and solar PV lifetimes were changed from 30 years to 25 years while geothermal lifetime was changed to 20 years. Battery storage lifetime was kept at 15 years which compares well to RESOLVE17-18's financial modeling whereby the 10-year storage lifetime included 10-year replacement, for a total of a 20-year lifetime.

After updating the Capital Recovery Periods, which increased *LCOE*[xli], *LCOC* was calculated as follows:

$$(a)\ LCOC\ \left(\$/_{kw-yr}\right) = LCOE\ \left(\$/_{MWh}\right) * NCF * \frac{8760}{1000}$$

This relationship follows from the definitions of levelized costs:

$$(b)\ LCOE \stackrel{\text{def}}{=} \frac{\sum_{t=1}^{L} \frac{C_t}{(1+r)^t}}{\sum_{t=1}^{L} \frac{E_t}{(1+r)^t}}$$

where:

- L is resource lifetime/financing period (years)
- C_t is the all-in cash expenditure in for the resource in year t (real dollars).
- r is the real discount rate (%)
- E_t is the total electricity production for the resource in year t (MWh).

Levelized cost of capacity can be defined similarly:[xlii]

$$(c)\ LCOC \stackrel{\text{def}}{=} \frac{\sum_{t=1}^{L} \frac{C_t}{(1+r)^t}}{\sum_{t=1}^{L} \frac{K}{(1+r)^t}}$$

where K is the nameplate capacity in kilowatts.

The conversion from $LCOE$ to $LCOC$ is possible if the following is true:

$$(d)\ E_t = K * NCF * 8760, \text{ for all } t.$$

Equation *(d)* implies that $LCOE$ can be converted directly to $LCOC$ if the annual E generation is a constant multiple of capacity in each year. This implies that there is a factor, $\frac{NCF*8760}{1000}$, which exactly converts $LCOE$ into $LCOC$. However, if resources undergo degradation, Equation *(d)* would not strictly hold and the relationship would be:

$$(e)\ E_t = K * CF_0 * 8760 * \delta^t,$$

where δ is the annual degradation factor (%) and CF_0 is the initial, maximum capacity factor of the resource. Stated differently, the capacity factor of the resource may differ each year:

$$(f)\ E_t = K * CF_t * 8760, \text{ where } CF_t = CF_0 * \delta^t$$

NREL's workbook notes that annual degradation was modeled in the Solar PV LCOE, but not for wind nor geothermal. Therefore, the conversion for wind and geothermal is exact while for solar PV it is approximate. However, the solar PV approximation is rigorous because NREL's NCF measures the average capacity factor over the resource lifetime, accounting for degradation. Since NCF includes degradation for Solar PV, Equation *(d)* approximates in Equations *(e)* and *(f)* in each year and Equation *(a)* is also approximate. Under the assumption of no degradation for wind and geothermal, Equation *(a)* holds exactly because NCF = CF_t in all years.

For Offshore Wind, LCOC was calculated from LCOE and NCF data for six California locations in the December 2016 California offshore wind study rather than 2018 NREL ATB. These data were preferred because of a closer mapping to California potential and costs, whereas 2018 NREL ATB mainly distinguished between Floating and Fixed Bottom.

Lastly, SCE multiplied the results of Equation *(a)* by an inflation factor to convert to real 2019 dollars from real 2016 dollars. The inflation factor was 1.0666 which equates to an annual average inflation rate of 2.17% between 2016 and 2019.

The input data for renewable resource costs and pumped storage for 2045 are depicted in the following table. These costs are shown in the denomination used in the source documentation – real 2016 dollars.

Table 13: Capacity Expansion Resource Costs

Resource Name	Levelized Cost of Energy (real 2016 $/MWh)	Net Capacity Factor (%)	Levelized Cost of Capacity (real 2016 $/kw-yr)	References
Solar (Average of NREL Los Angeles and Daggett locations)	$21	25%	$46	NREL 2018 Annual Technology Baseline; 2018-ATB-data-interim-geo.xlsm; sheet: Solar - Utility PV; https://atb.nrel.gov/electricity/2018/
Wind (Average of NREL Techno-Resource Groups 6-9)	$55	39%	$187	Ibid.; sheet: Land-Based Wind; average of techno-resource groups 6 through 9.
Geothermal (Conventional, Flash)	$86	90%	$678	Ibid.; sheet: Geothermal; Hydro/Flash - Mid.
Geothermal (Conventional, Binary)	$115	80%	$807	Ibid.; sheet: Geothermal; Hydro/Binary - Mid.
Geothermal (Enhanced, Flash)	$154	90%	$1,211	Ibid.; sheet: Geothermal; Deep ERG/Flash - Mid.
Geothermal (Enhanced, Binary)	$248	80%	$1,738	Ibid.; sheet: Geothermal; Deep ERG/Binary - Mid.
Offshore Wind (average of 6 California sites)	$95	58%	$481	NREL; Potential Offshore Wind Energy Areas in California: An Assessment of Locations, Technology, and Costs; December 2016; Spreadsheet for CA Offshore Wind Cost Estimates (PUBLIC).xlsx; https://www.nrel.gov/docs/fy17osti/67414.pdf.
Pumped Hydro	$63	50%	$278	RESOLVE model with 2017 IEPR; RESOLVE_User_Interface 2018-04-17.xlsm; sheet: STOR_Inputs; values in U74 and U80; https://www.cpuc.ca.gov/General.aspx?id=6442457210.

As previously described, the Heavy Solar and Balanced scenario differed in the availability and cost of some renewable resources. In the Balanced scenario, the in-state solar portion of the supply curve tilts upward due to transmission costs and out-of-state solar was not available. The following figures illustrate the resource supply curve – a cumulative distribution of renewable generation capacity available at or below a given price.

Figure 7: Balanced - 2045 Supply Curve

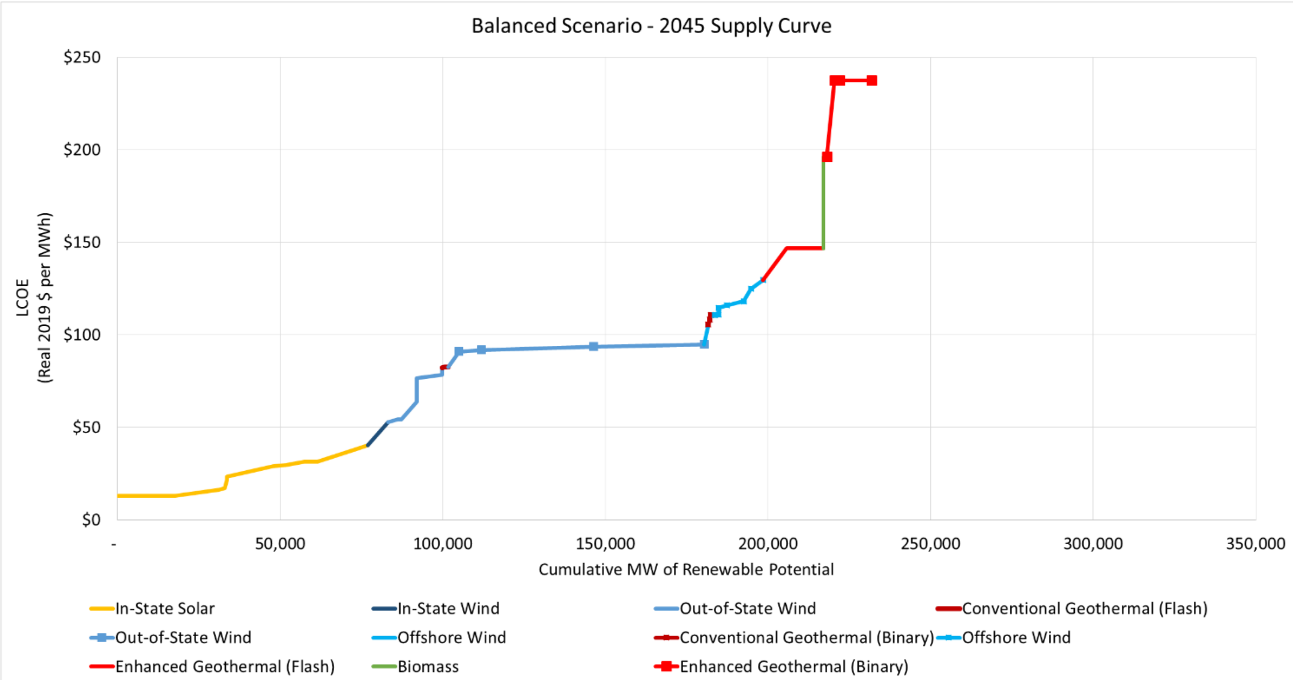
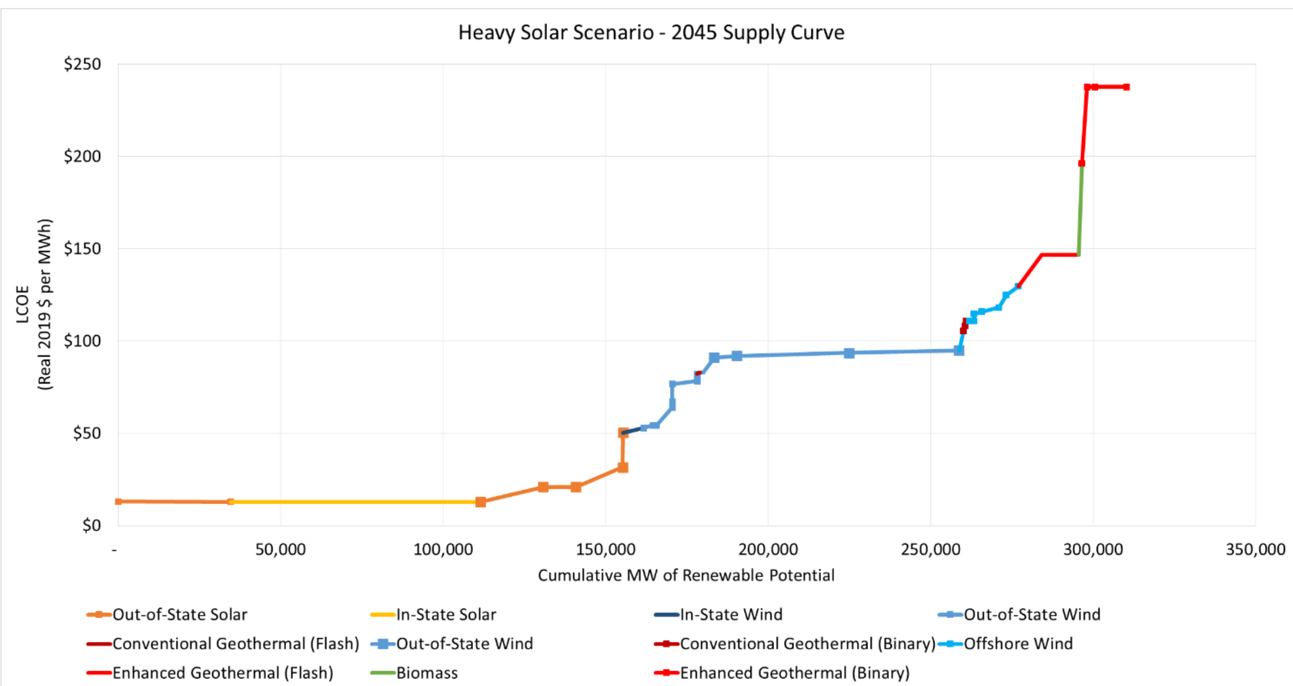


Figure 8: Solar Heavy - 2045 Supply Curve



Battery Storage Cost Derivation

Battery storage costs were calculated differently than renewable generation resources because NREL's ATB data did not include an explicit amortization. Unlike renewable generation, battery storage included both fixed cost and variable cost components. As with renewable generation, only the fixed costs were used for the LCOC. Variable costs were inflated to real 2019 dollars used directly by the capacity expansion model.

The LCOC was calculated using NREL's Battery Pack Capital Cost ($/kWh), Balance of System Capital Cost ($/kW), Fixed Operation and Maintenance Expenses ($/MW-yr), Book Life, and Weighted Average Cost of Capital (real). The LCOC was separately amortized as a capacity component (i.e. balance of system) and energy component (i.e. battery pack) so that costs for systems of various durations could be calculated. The capacity component was amortized according to a standard loan payment relationship:

$$FC_c = \frac{K_c * r}{1 - (1 + r)^{-L}} + FOM$$

where,

- FC_c is the capacity component of levelized fixed costs ($/kw-yr)
- K_c is the capital expenditure for balance of system components ($/kw)
- r is the discount rate, measured by weighted average cost of capital (WACC, %)
- L is the resource lifetime (years)
- FOM is the average annual fixed operating & maintenance cost of the energy storage system ($/kw-yr)

Similarly, the energy component was amortized according to a standard loan payment relationship:

$$FC_e = \frac{K_e * r}{1 - (1 + r)^{-L}}$$

where,

- FC_e is the energy component of levelized fixed costs ($/kwh-yr)
- K_e is the capital expenditure for 1 kwh of battery packs ($/kwh)
- r is the discount rate, measured by weighted average cost of capital (WACC, %)
- L is the resource lifetime (years)

Finally, the levelized fixed cost for a battery energy storage system is taken as a function of the levelized fixed cost of capacity, the levelized fixed cost of energy, and the storage duration:

$$LCOC\ (^{\$}/_{kw - yr}) = FC_c + H * FC_e$$

where H is the storage duration in hours.

The input data for battery storage costs for 2045 are depicted in the following table. These costs are shown in the denomination used in the source documentation – real 2016 dollars.

Table 14: Battery Storage Resource Costs

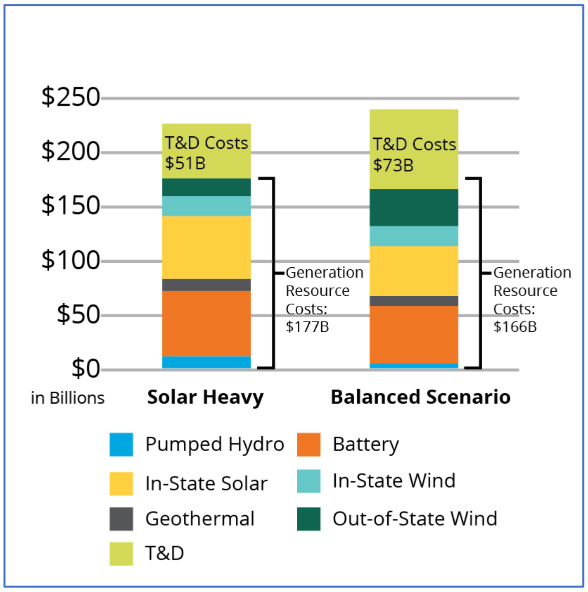
Resource Name	Capital Cost (real 2016 $/kw)	Levelized Cost of Capacity (real 2016 $/kw-yr)	References
1 Hour Lithium-Ion Battery System	$ 575	$ 53	NREL 2018 Annual Technology Baseline; 2018-ATB-data-interim-geo.xlsm; sheet: Storage; https://atb.nrel.gov/electricity/2018/
2 Hour Lithium-Ion Battery System	$ 752	$ 67	
3 Hour Lithium-Ion Battery System	$ 930	$ 81	
4 Hour Lithium-Ion Battery System	$ 1,107	$ 95	
5 Hour Lithium-Ion Battery System	$ 1,285	$ 110	
6 Hour Lithium-Ion Battery System	$ 1,462	$ 124	
7 Hour Lithium-Ion Battery System	$ 1,640	$ 138	
8 Hour Lithium-Ion Battery System	$ 1,817	$ 152	
9 Hour Lithium-Ion Battery System	$ 1,994	$ 166	
10 Hour Lithium-Ion Battery System	$ 2,172	$ 181	

5. Capital Costs Comparison Between Scenarios

Direct capital costs associated with the projected new generation resource requirements in 2045 for the Solar Heavy and Balanced scenarios are projected, excluding any BTM solar and storage costs. Additionally, the projected transmission and distribution (T&D) associated with each of the scenarios is added to the resource costs, as these T&D investments enable the full utilization of these new generation resources.

Under both scenarios, there is significant capital investment in new generation resources, with the Solar Heavy scenario having higher generation resource costs (due to higher in-state resource development) but lower T&D capital costs. The Balanced scenario shows higher T&D capital costs associated with bringing additional out-of-state wind into the CAISO footprint and lower new generation resource costs. The total cost of each scenario is within 5% of the other.

Figure 9: Total Direct Capital Costs, 2019 $



Given the uncertainties associated with such a long-time horizon into the future, the quantity of resources needed, the type and location of resources, one scenario is not favored over the other.

More work needs to be done to more fully understand all the potential implications and impacts of a decarbonized electric grid.

6. Bulk Storage Detailed Results and Implications

Battery storage buildout is dependent on load profile, renewable generation profiles, and costs. Contrary to most near-term modeling which consist of mostly 4-hour batteries, SCE's 2045 modeling found that substantially longer duration Li-ion batteries between 6-hour and 9-hour are required for a high renewable energy profile. SCE's ABB capacity expansion optimized the model by stacking different types of storage to create the least cost portfolio to satisfy demand. Storage serves both capacity and generation needs of the portfolio. Longer duration battery is cheaper on a per MWh basis but more expensive on a per MW basis; therefore, longer duration battery is only selected if there is an energy need for storage. The Solar Heavy scenario requires not only longer duration batteries but also larger quantities of storage than the duration and amount required by the Balanced scenario. In the Solar Heavy scenario solar dominance necessitates more hours being served by battery.

Table 15: Storage Duration Selected

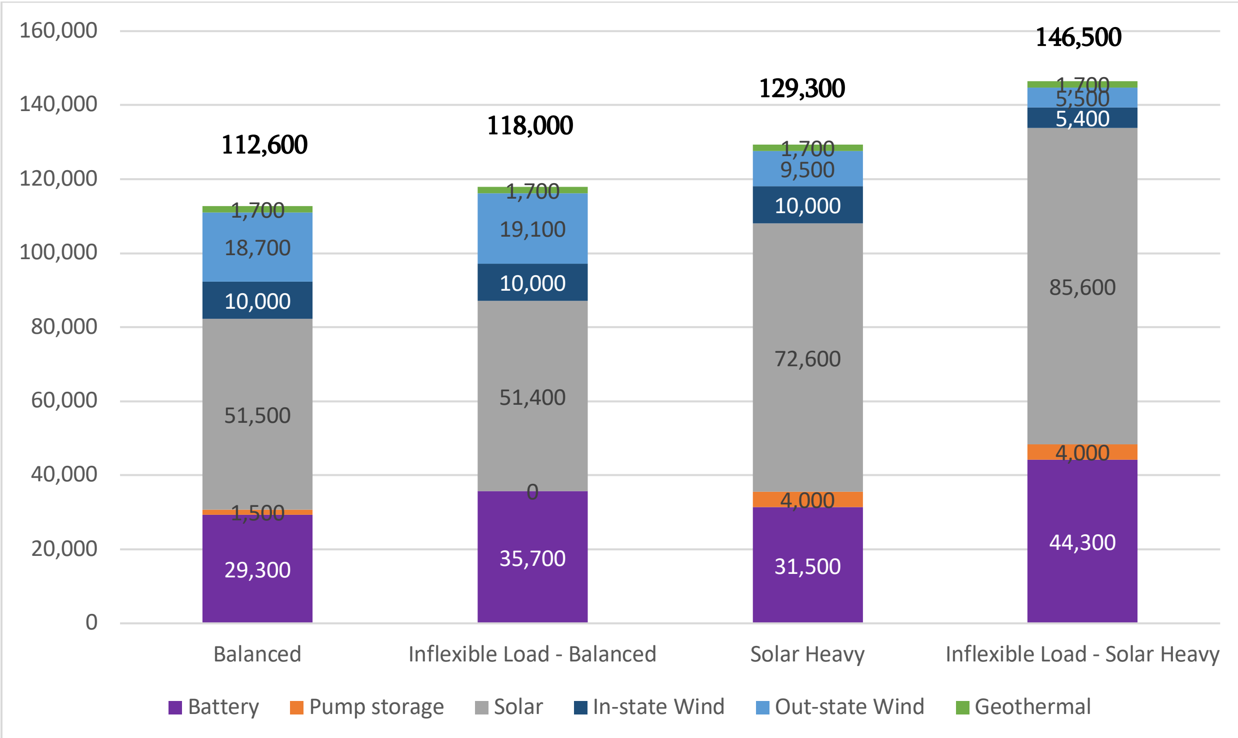
Storage Duration	Solar Heavy (MW)	Balanced (MW)
5 Hr Li-ion	4,520	4,520
6 Hr Li-ion	3,229	5,942
7 Hr Li-ion	5,809	13,441
8 Hr Li-ion	17,071	4,559
9 Hr Li-ion	0	0
12 Hr Pump Storage	4,000	1,483

7. Load Flexibility Impact on Resource Portfolio

As discussed in Appendix A, there is significant load flexibility assumed in the 2045 demand forecast, driven by more effective TOU rates and control technologies that enable pre-cooling of buildings and spreads out future EV charging loads. In order to test the impact of not achieving the assumed level of future load management in the demand forecast, the assumed flexibility associated with light-duty electric vehicle charging was reduced, resulting in a higher and more pronounced peak load in the evening. A resource portfolio was then developed to address this less flexible load profile.

As expected, the results below show additional renewable generation and storage capacity for both the Solar Heavy and Balanced scenarios. The Solar Heavy scenario required over 17 GW of additional resources. The Balanced portfolio, on the other hand, seems to better absorb this load profile change, requiring 5 GWs of additional storage capacity to serve the less flexible load profile.

Figure 10: Load Flexibility Sensitivities



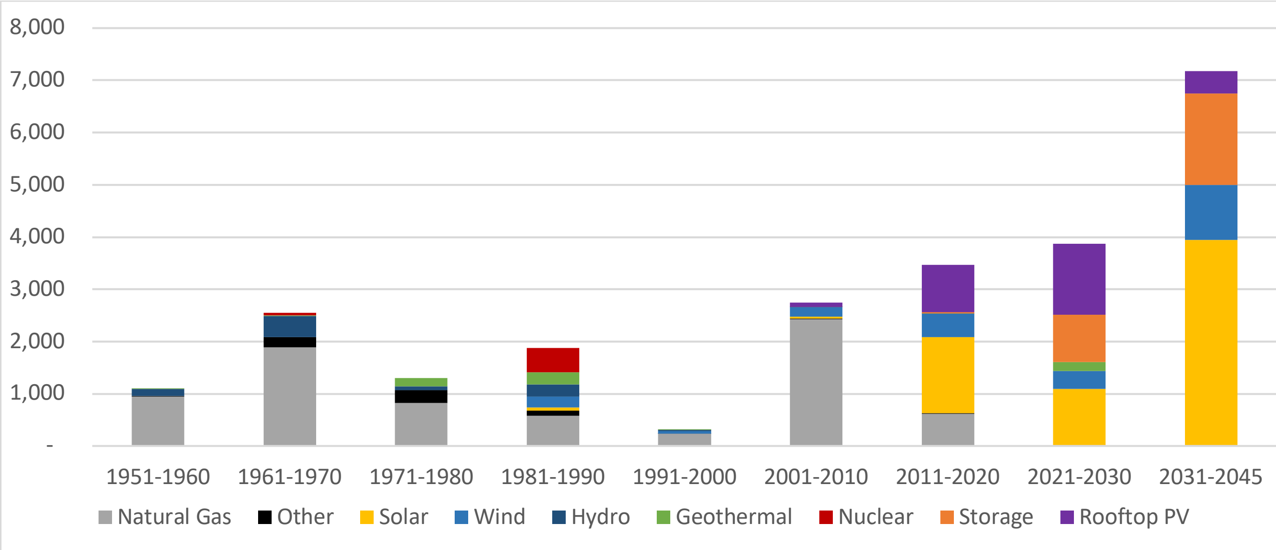
8. Alternative Renewable Technologies

SCE conducted multiple sensitivities of alternative renewable technologies, particularly focusing on offshore wind and enhanced geothermal. Currently, solar is projected to be widely available in California, and both solar and storage are projected to achieve significant cost reductions. SCE learned from this analysis that for alternative technologies to become competitive with conventional renewable resources, these alternative technologies would need to be cost competitive with solar-storage pairings and would also need to have a generation profile that produces energy during non-solar hours and low-solar seasons.

9. Historical Capacity Expansion Levels

Historical and forecasted generation capacity additions to CAISO averaged over ten-year periods are shown in Figure 11. For future resources, the data also includes renewable resources that are contracted to CAISO entities, but may not be directly interconnected.

Figure 11: Average Annual CAISO Additions (MW)



Source - Energy Velocity[xliii]

From the 1950s to the 1980s annual capacity additions to CAISO have averaged around 2 GW per year coinciding with increased energy usage as part of California's growing economy. From 1991 to 2000, annual capacity additions were extremely low. However, since 2001, capacity additions have been historically high due to short-term reliability concerns in the early 2000s and renewables portfolio standard legislation.

Forecasted capacity additions from 2021 to 2030 are estimated to be close to near-term historical levels, but still above long-term trends. Annual capacity additions from 2031 to 2045 are expected to nearly double relative to the amounts in decades before. In general, large forecasted capacity additions are due to: (1) increased load from electrification, (2) renewables to decarbonize energy supply, (3) lower capacity factors of renewables relative to fossil generation, and (4) a need for storage capacity to shift non-dispatchable renewable energy.

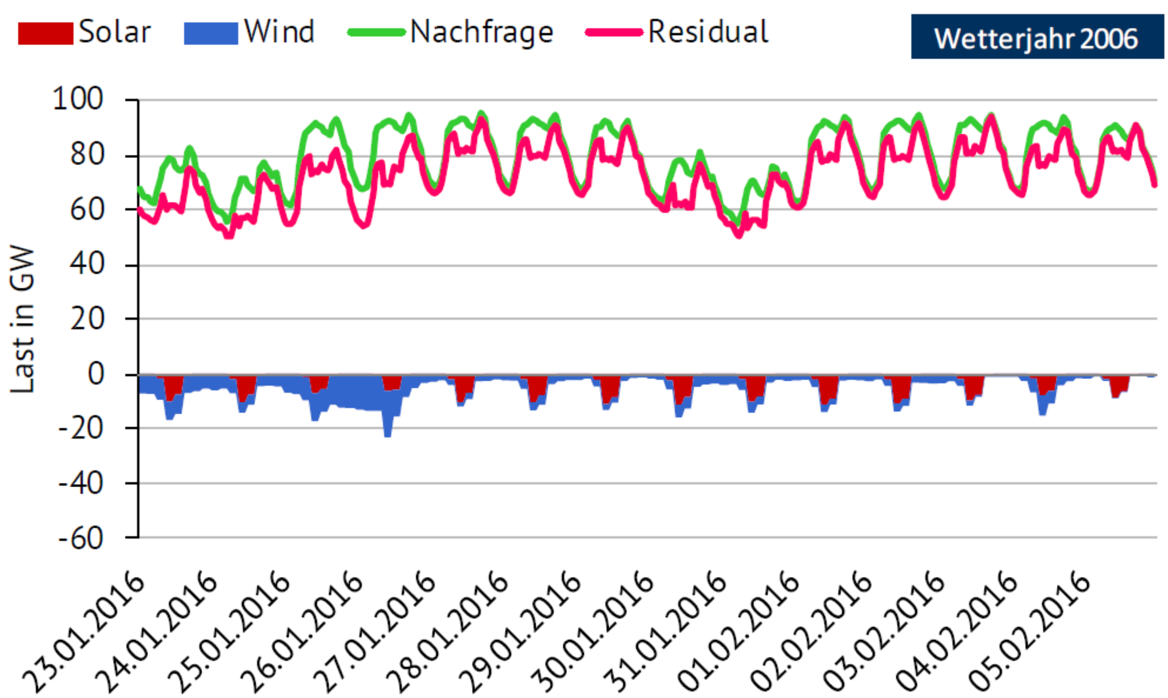
10.Stormy Skies Analysis

Will California Experience an extended period of low renewable production like Germany's Dark Doldrums?

Background

As renewable generation increases in California, especially solar and wind, there is a growing concern that California could face a similar situation as Germany where there can be an extended period of low renewable production. In Germany, this period is known as the Dark Doldrums where Germany's heavy reliance on wind could fail to provide significant generation over a multi-day period. For example, using historical 2006 weather data with Germany's 2016 renewable portfolio, Germany could have experienced very low renewable production as indicated by the blue and red shaded parts of Figure 12. The red line in the Figure 12 represents the remaining load that needs to be met with either fossil resources or imports.[xliv]

Figure 12: Germany Load & Renewable Production Simulation (2006 weather, 2016 portfolio)



As California continues its path to decarbonize the electric sector, California may face a similar situation of low renewable production mainly driven by low solar generation caused by large storm systems (a.k.a., Stormy Skies). To explore the validity of this occurring in California, SCE did an initial analysis of the 2045 resource buildout applying 2018-19 weather and corresponding renewable generation. The 2018-19 weather season was chosen as it represents a recent time period that had numerous storms that could potentially reduce renewable generation for a multi-day period. This initial analysis was to provide some insights into two potential issues: (1) low amounts of renewable production and (2) reliability concerns.

Methodology

SCE used a similar technique used in the German Dark Doldrums analysis to approximate the renewable energy produced during a period. We used the historical weather period of January 10, 2019 to January 19, 2019. The corresponding renewable production for the same time period was obtained from ABB Velocity Suite.

Once the historical renewable energy production was obtained for the time period, the next step was to determine the total theoretical energy available by generating resources. The renewable production was then scaled according to the 2045 buildout for each scenario which determined the CAISO renewable generation. For other resources (e.g., natural gas, hydro, and imports), their max production was assumed to be available. Using these pieces of information, the total available energy from resources was determined.

The next step was to determine the hourly load. The 2045 load for the same days (January 10, 2045 to January 19, 2045) was used as the starting point. Since BTM solar would be similarly affected by a storm system in California, we adjusted the load impact of BTM solar by assuming it would have the same profile as utility scale solar and scaling it appropriately for 2045. In addition, storage losses were treated as an additional "load." Any available energy in excess of load was assumed to be stored and subjected to the storage loss of 10% which was added to the load needed to serve.

Findings and Conclusions

During the one week period of January 11 to 17, the solar production dropped 45% when compared to January 19th. More notably, for the 14th and 15th, the solar production was even lower at 21-23% which is highlighted in Table 16. This reduced solar production had a direct impact on the ability to serve the 2045 load.

Table 16: Daily Solar Energy Simulation (January 11-17, 2019)

Date	Daily Solar Energy (MWh)	% of 1/19
1/10/2019	53,231	87%
1/11/2019	39,551	65%
1/12/2019	29,071	48%
1/13/2019	47,382	78%
1/14/2019	12,684	21%
1/15/2019	13,718	23%
1/16/2019	30,941	51%
1/17/2019	18,055	30%
1/18/2019	50,018	82%
1/19/2019	60,886	100%
Avg (1/11 - 1/17)	27,343	45%

We compared the daily energy available with the total load which is summarized in the Table 17. Based on the analysis, the total daily available energy would be able to cover the daily load. However, for the two days with substantial lower solar production, January 14th and 15th, the margin of available energy is extremely small at 5-6% of load. It is likely that careful planning would be required to utilize storage in a multi-day energy shifting operation to ensure load was served.

Table 17: Daily Energy Available and Total Load (MWh)

	Solar Heavy Scenario			Balanced Scenario		
Date	Energy Available	Total "Load"	Difference	Energy Available	Total "Load"	Difference
1/10/2045	1,413,542	1,102,906	310,637	1,348,048	1,095,030	253,019
1/11/2045	1,282,951	1,058,879	224,072	1,241,388	1,053,428	187,961
1/12/2045	1,169,095	1,056,830	112,266	1,145,808	1,053,035	92,773
1/13/2045	1,337,914	1,069,826	268,087	1,282,636	1,062,718	219,918
1/14/2045	1,067,309	1,013,434	53,876	1,072,427	1,012,702	59,726
1/15/2045	1,066,374	1,008,141	58,233	1,070,110	1,007,220	62,890
1/16/2045	1,262,874	1,086,321	176,553	1,236,422	1,082,329	154,092
1/17/2045	1,209,467	1,103,955	105,512	1,205,614	1,102,360	103,254
1/18/2045	1,465,066	1,124,561	340,505	1,404,531	1,117,472	287,059
1/19/2045	1,453,689	1,225,114	228,575	1,373,649	1,215,726	157,923

To have a similar situation as in the Dark Doldrums, an extensive period of low solar production (less than 25% relative to normal) would be required. Based on the 2018-19 winter season, the initial analysis indicates that this would be a relatively rare occurrence as most storm events did not have sufficient impact to reduce solar production by that much. In addition, the period studied did show a relatively higher amount of wind production which offset some of the lower solar production. It is unclear if this higher wind production is consistently occurring during storms (i.e., the weather system could potentially be creating higher levels of wind speed which is increasing wind generation).

As indicated in the daily energy table, there are two days of concern where the total daily energy may not be sufficient to meet the daily load requirement. From the previous days, there is more energy available that could be stored for the days of concern. However, careful storage operations would be necessary to ensure that load can be met.

SCE notes that this analysis is an initial view on California's Stormy Skies situation. Further work is needed to explore other historical weather years to determine if there are more severe periods of low solar and wind production. In addition, further refinements on the availability of other resources is needed to determine the reliability impacts such as unserved energy and any impacts on meeting the 1-in-10 reliability metric.

11.Relevant Policies

Decarbonization

- **Executive Order S-3-05** established targets to reduce GHG emissions 40% below 1990 levels by 2030, and 80% below 1990 levels by 2050
- **SB 32** codified GHG target of reducing emissions 40% below 1990 levels by 2030
- **Executive Order B-55-18** established a statewide goal to achieve carbon neutrality by the year 2045.

Electric Sector

- **SB 100** requires 60 percent RPS by 2030 and carbon-free resources serve 100% of retail electricity sales by 2045

Transportation Electrification

- **SB 856** Budget Act provides funding for Clean Vehicle Rebate program, and various TE grant programs for low and moderate income and medium and heavy duty TE.
- **SB**
- **1014 r**equires CARB and the CPUC to adopt and implement the California Clean Miles Standard and Incentive Program to increase the use of zero-emission vehicles by ride-hailing companies.
- **AB 2127** Requires the CEC conduct biennial assessment of EV charging infrastructure needs to support 5 million ZEVs on California roads by 2030.
- **Executive Order B-48-18** creating target of 5 million ZEVs by 2030 and sets ZEV infrastructure goals of 200 hydrogen fueling stations and 250,000 zero-emission vehicle chargers, including 10,000 direct current fast chargers, by 2025.
- CARB approved the **second cycle of investment from the Volkswagen Settlement**, which plans to invest $800 million over a 10-year period in zero-emission vehicle charging infrastructure, public outreach on zero-emission vehicles.
- Approval of **$738M in IOU MD/HD charging infrastructure programs.**
- **ZEV Mandate for transit buses**: CARB required transit agencies to have 100% of new bus purchases be zero-emissions buses by 2029, with a goal of reaching a 100% ZE bus fleet statewide by 2040.
- **LCFS Funding** for vehicle rebates.

Building Electrification

- **SB 1477** requires the CPUC, using a **gas corporation's cap-and-trade auction revenues ($50M/year for five years)**, to develop a statewide market transformation initiative **for low-emission space and water heating** for residential and nonresidential buildings, and to develop an incentive program to fund near-zero-emission technology for new residential and commercial buildings.
- **AB 3232** requires CEC, CPUC and CARB to assess potential to reduce GHG in residential and commercial buildings to meet SB32 GHG reduction goals
- **2019 Title 24** began to level the playing field between gas and electric technologies by adding heat pump water heater and all-electric compliance options. During the May 9th adoption hearing, the CEC mentioned a **"Move to a more GHG-based metric that promotes electrification"** in future code updates
- CPUC initiating BE OIR in 2019
- **Energy Efficiency –** CEC IEPR interpretation of SB350 "doubling of energy efficiency"
- **Rooftop Solar –** building code standards
- **Behind-the-meter Storage –** SGIP renewal

Other

- **SB 350** sets a goal for California to reduce greenhouse gas emissions to 40 percent below 1990 levels by 2030 and to **80 percent below 1990 levels by 2050**
- **Executive Order B-55-18** orders California agencies to work together to achieve **carbon neutrality** in California by 2045

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