# Long-Run Resource Adequacy under Deep Decarbonization Pathways for California

June 2019





Energy+Environmental Economics



# Long-Run Resource Adequacy under Deep Decarbonization Pathways for California

June 2019

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## **Disclaimer Required by the California Public Utilities Commission**

This report has been prepared by E3 for the Calpine Corporation. This report is separate from and unrelated to any work E3 is doing for the California Public Utilities Commission. While E3 provided technical support to Calpine in preparation of this report, E3 does not endorse any specific policy or regulatory actions as a result of this analysis.

The study uses three E3 models as the basis for analysis: California-wide PATHWAYS and RESOLVE models developed under California Energy Commission contract number EPC-14-069 and a California-wide version of E3's RECAP model developed for this project. Versions of these models have previously been used by E3 for projects completed on behalf of the California Energy Commission, the California Public Utilities Commission, and the California Air Resources Board. These California state agencies did not participate in the project and do not endorse the conclusions presented in this report.

The RESOLVE model used for this project is distinct from the RESOLVE model developed for the CPUC's 2017-2018 Integrated Resource Planning proceeding (R.16-02-007). The following table summarizes the major differences in the RESOLVE model version used for this study and the version used in the CPUC's IRP proceeding.

Category	Assumption(s) for this study	Difference from CPUC IRP
Geography	California Independent System	California Independent System
	Operator (CAISO) +	Operator (CAISO) only.
	Sacramento Municipal Utilities	
	District (SMUD) + Los Angeles	
	Department of Water and	
	Power (LADWP).	

#### Table E-1. Key Differences in RESOLVE Input Assumptions as Compared to CPUC IRP Proceeding

Natural gas fixed O&M costs	Going-forward cost to	Included in total fixed costs.
	maintain existing natural gas	
	generation set to \$50/kW-yr.	
Natural gas generation	Modeled with assumed cost	Not modeled.
economic retirement	savings equal to fixed O&M	
	costs.	
Renewable and battery storage	Costs updated to be consistent	Renewable cost assumptions
costs	with the 2018 National	developed by Black & Veatch
	Renewable Energy Lab (NREL)	for RPS Calculator V6.3 Data
	Annual Technology Baseline	Updates; battery storage cost
	(ATB) and Lazard Levelized	assumptions derived from
	Cost of Storage v3.0.	Lazard Levelized Cost of
		Storage v2.0 and DNV GL's
		Battery Energy Storage Study
		for the 2017 IRP.
Wind resource limitations	Limited to 2,586 MW in-state	Limited to 2,586 MW in-state
	and 12,000 MW out-of-state	and 2,442 MW out-of-state
	(WY/NM/PNW).	available on existing
		transmission in the CPUC
		adopted 2017 RSP. A total of
		96,758 MW out-of-state wind
		available on new & existing
		transmission.
RPS target	60% by 2030, 100% by 2045	50% by 2030 (SB 350
	(SB 100 compliant).	compliant).
EV charging flexibility	By 2030, 30% of EV load is	Default assumption of no
	flexible, and 25% of EV owners	flexible charging.
	have access to workplace	
	charging.	

## Conventions

The following conventions are used throughout this report:

- + All costs are reported in **2016 dollars.**
- + All levelized costs are assumed to be **levelized in real terms** (i.e., a stream of payments over the lifetime of the contract that is constant in real dollars).

## Acronyms

CARB	California Air Resources Board
CEC	California Energy Commission
CPUC	California Public Utilities Commission
ELCC	Effective Load Carrying Capability
GHG	Greenhouse Gas
LBNL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLF	Loss of Load Frequency
LOLP	Loss of Load Probability
NREL	National Renewable Energy Laboratory
PRM	Planning Reserve Margin
RA	Resource Adequacy
RPS	Renewables Portfolio Standard

## **Executive Summary**

This study examines electricity system resource adequacy under future scenarios in which California's economy is deeply decarbonized and heavily dependent on renewable energy. Resource adequacy standards ensure that sufficient resources are available to meet electric load under the broadest possible range of weather and resource outage conditions, subject to a standard for acceptable reliability. The study builds on prior work that E3 completed for the California Energy Commission which evaluated alternative pathways for California to achieve 80% reductions in greenhouse gas emissions from electricity, buildings, transportation, and industry by 2050. The previous work identified measures California could take to achieve greenhouse gas reductions and renewable energy targets within the electricity sector. The current study takes an in-depth look at electricity system resource adequacy requirements and which resources are needed to maintain acceptable long-run resource adequacy in a cost-effective manner under a range of plausible assumptions. This study was funded by the Calpine Corporation.

This study uses three well-known E3 models of the California electricity system which have been used extensively by state agencies, utilities, and stakeholders to examine similar questions: PATHWAYS, RESOLVE, and RECAP. Using E3's California PATHWAYS model, an economy-wide GHG and cost accounting tool, we first consider two alternative scenarios for meeting the economy-wide goal of 80% GHG reductions below 1990 levels by 2050:

- + The **High Biogas** scenario includes a significant amount of electrification but utilizes renewable natural gas and hydrogen in buildings, transportation, and industry, resulting in electric loads that are significantly higher than today but lower than in the High Electrification scenario.
- + The High Electrification scenario includes the near-complete electrification of space heating and cooling loads in buildings as well as transportation, resulting in much higher electric loads than in the High Biogas scenario.

Both scenarios include enough GHG abatement measures to meet economy-wide goals, including a target for electricity sector carbon emissions.

We then use RESOLVE, E3's capacity expansion model, to develop optimal portfolios that meet electricity sector GHG targets and reliability requirements at least cost, taking the electricity sector carbon targets and electric loads from each PATHWAYS scenario as inputs.

Finally, we use RECAP to test the resource adequacy of the portfolios developed in RESOLVE, adding resources if needed to meet a defined reliability standard. This is an important extension of our prior deep decarbonization work as it can inform solutions to the complex electric reliability challenges associated with very high renewable energy penetrations.

## **Key Findings**

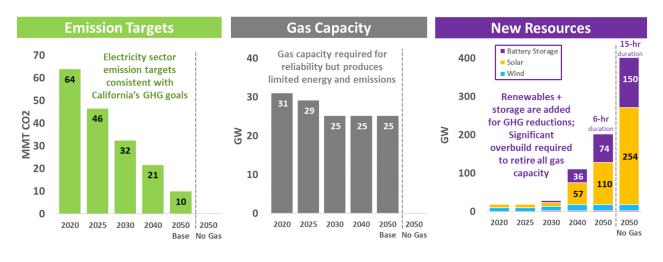
- The least-cost plan for achieving the 2050 economy-wide goal of GHG reductions of 80% below 1990 levels for California requires electricity sector GHG emissions to be reduced to very low levels by 2050: <u>between 6 and 10 million metric tons</u>, or 90-95% below 1990 levels.<sup>1</sup>
  - + Achieving economy-wide goals <u>does not require complete decarbonization</u> of electricity supply.
- Some form of <u>firm generation capacity</u> is needed to ensure reliable electric load service on a deeply decarbonized electricity system.

<sup>&</sup>lt;sup>1</sup> 1990 California electricity generation emissions total 111 MMT CO2e GHG. Source: https://www.arb.ca.gov/cc/inventory/pubs/reports/staff\_report\_1990\_level.pdf

- + Firm generation capacity refers to electric energy resources that can produce energy on demand during extended periods of time in which wind and solar energy are not available.
- Natural gas generation capacity is currently the most economic source of firm capacity. The least-cost electricity portfolio to meet the 2050 economy-wide GHG goals for California includes <u>17-35 GW of natural gas generation capacity</u> for reliability. This firm capacity is needed even while adding very large quantities of solar and electric energy storage.
- + A firm fuel supply is required to ensure that natural gas generation capacity can produce electricity when needed.
- Alternative technologies can reduce the need for firm natural gas generation capacity but have significant limitations.
  - Wind, solar, energy storage and demand response can contribute to resource adequacy but, at high penetrations, have important limitations in their ability to substitute for firm capacity.
  - + Geothermal energy provides firm capacity and is selected up to the state's assumed technical potential, but that potential is limited.
  - + Biogas or carbon-neutral gas is considered in this study but not selected for electricity generation due to higher-value applications in other sectors. Selection of biogas for electricity generation would not change the study's conclusions about the need for firm capacity to maintain electric reliability; in fact, the biogas would likely use the same fuel delivery and electric generation infrastructure as is used for fossil natural gas generation in this study.
  - + Other low-carbon alternatives to natural gas generation capacity for maintaining resource adequacy at scale are not considered in this study. These include nuclear,

fossil generation with carbon capture and storage, and renewables with ultra-long duration energy storage.

- It would be <u>extremely costly and impractical</u> to replace all natural gas generation capacity with solar, wind and storage, due to the very large quantities of these resources that would be required.
- 5. The findings are robust to all key sensitivity drivers. Between 15 and 33 GW of gas capacity is retained even under an electric sector carbon budget as low as 3 million metric tons by 2050.



#### **ES-1: Key Conclusions Overview**

## **1** Introduction

## 1.1 California's Energy and Climate Agenda

California has ambitious decarbonization goals and renewable energy targets. Some of the major policies establishing these goals include:

- + 2006: Global Warming Solutions Act (AB 32) authorizes the California Air Resources Board (CARB) to monitor and regulate greenhouse gases. The initial target in this law was to reduce greenhouse gas emissions to 1990 levels by 2020, representing approximately a 30% reduction.
- + 2015: Executive Order B-30-15, issued by Governor Jerry Brown, reaffirms greenhouse gas emission reduction target of 80% below 1990 levels by 2050.
- + 2015: SB 350 mandates that electric utilities purchase 50% of their electricity from renewable sources by 2030.
- + 2016: SB 32 expands upon AB 32 and requires the state to ensure that greenhouse gas emissions are reduced to 40% below 1990 levels by 2030.
- + 2018: SB 100 increases the renewable targets set under SB 350 to 50% by 2026 and 60% by 2030.
   The law also requires eligible renewable energy resources and zero-carbon resources to supply 100% of retail sales of electricity to California end-use customers by 2045.
- + 2018: Executive Order B-55-18, issued by Governor Jerry Brown, articulates a goal of economywide carbon neutrality no later than 2045.

It is important to note that SB 100 does not expressly prohibit the use of natural gas for electricity generation in California after 2045. While it commits the state to plan for sufficient supply of zero-carbon

resources to meet 100% of retail sales, it does not require electric load to be balanced instantaneously with zero-carbon resources. Rather, consistent with implementation of the state's Renewables Portfolio Standard, SB 100 could enable the CPUC and CEC to establish compliance periods of a year or longer and to consider banking and borrowing of clean energy credits to reflect annual variations in the available quantity of wind, solar, and hydro energy. This would allow California to export some of the carbon-free energy that it procures, effectively offsetting in-state natural gas electricity generation needed for reliability while meeting SB100 goals. Thus, a key question going forward is what role natural gas generation capacity may play in balancing renewable generation and maintaining resource adequacy for a deeply decarbonized electricity grid.

### **1.2** Prior Studies of Deep Decarbonization

Multiple studies have examined approaches to meeting California's aggressive decarbonization goals. Together, they establish a blueprint for how California might decarbonize its energy supply. Key studies include:

- + Scenarios for Meeting California's 2050 Climate Goals (2013) was commissioned by the California Energy Commission (CEC) and jointly completed by the University of California, Berkeley and the Lawrence Berkeley National Laboratory (LBNL).<sup>2</sup> Using the California Carbon Challenge 2 model, the study examined a range of sixteen different scenarios, reflecting a range of assumptions on technology availability, cost, and deployment, to quantify a range of impacts to meet California's 80% greenhouse gas reduction goal.
- + California PATHWAYS Project<sup>3</sup> (2015) was jointly commissioned by the California state agencies and completed by E3 with the dual purposes of studying possible pathways to the state's 2050 80% reduction goal and informing the establishment of an interim 2030 goal. The study used E3's

<sup>&</sup>lt;sup>2</sup> Available at: https://www.energy.ca.gov/2014publications/CEC-500-2014-108/CEC-500-2014-108.pdf

<sup>&</sup>lt;sup>3</sup> Available at: http://www.ethree.com/wp-content/uploads/2017/02/E3 PATHWAYS GHG Scenarios Updated April2015.pdf

PATHWAYS model to create four scenarios to achieve the 2050 target, capturing different options in technology pathways and rates of deployment.

- + Modeling of Greenhouse Gas Reductions Options and Policies for California to 2050<sup>4</sup> (2016) was completed by the Institute of Transportation Studies and the University of California, Davis. Using this CA-TIMES model, this study examined the costs of achieving various levels of carbon reduction goals and employed Monte Carlo analysis to examine the range of uncertainty in cost of achieving various levels of carbon reductions.
- + Deep Decarbonization in a High Renewables Future<sup>5</sup> (2018) was commissioned by the CEC and completed by E3. Using E3's California-wide PATHWAYS and RESOLVE models, it studies ten different mitigation scenarios to achieve the state's 80% greenhouse gas reduction goals, highlighting the important potential low-cost pathway of electrification of buildings and end uses.

Despite using different models and assumptions, these efforts have generally reached similar conclusions regarding the infrastructure transitions needed to achieve deep decarbonization goals. These studies, and similar studies in other geographies, have generally established four foundational elements as necessary for achieving aggressive decarbonization of the economy (Figure 1):

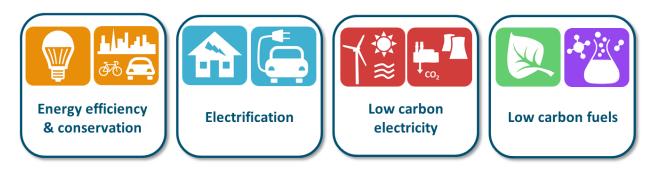
- + Deployment of ambitious levels of **energy efficiency and conservation** beyond levels of historical achievement;
- + Electrification of end uses traditionally fueled by fossil fuels, including vehicles, space and water heating, and industrial processes;
- + Production of **low-carbon electricity** to supply clean energy to both existing and newly electrified loads; and
- + Use of **low-carbon fuels**—for instance, biofuels, synthetic gas, and/or hydrogen—to supply energy to end uses that continue to rely on liquid and/or gaseous fuels.

<sup>&</sup>lt;sup>4</sup> Available at: https://steps.ucdavis.edu/wp-content/uploads/2017/05/2016-UCD-ITS-RR-16-09.pdf

<sup>&</sup>lt;sup>5</sup> Available at: <u>https://efiling.energy.ca.gov/GetDocument.aspx?tn=223785</u>

Notably, each study concludes that very deep decarbonization of the electricity sector is necessary to meet economy-wide goals, and none conclude that complete elimination of carbon emissions in the electricity sector is necessary. In fact, each study allocates a small amount of carbon emissions to the electricity sector to ensure reliable electricity service during periods of low wind and solar generation.

#### Figure 1. Four Pillars of Deep Decarbonization



## 1.3 Purpose of This Study

Prior studies of decarbonization in California focus primarily on investments needed to decarbonize energy and electricity supply. The electricity generation capacity and fuel delivery infrastructure needed to preserve reliability and ensure resource adequacy have been a secondary consideration.

This study examines the question of which resources are needed to maintain resource adequacy in a deeply decarbonized California electricity system that is heavily dependent upon renewable energy and electric energy storage. This project builds on E3's recent *Deep Decarbonization in a High Renewables Future* report for the CEC. Whereas the previous study identified which measures California could take to achieve economy-wide greenhouse gas reductions and electricity sector renewable energy targets, this study takes an in-depth look at electricity system reliability requirements and which resources are needed

to maintain acceptable long-run resource adequacy in a cost-effective manner under a range of plausible assumptions.

The key questions addressed by this study include:

- + What is an appropriate target for electricity sector GHG emissions in 2050 to meet economy-wide reduction goals at lowest cost?
- + What is the plausible range of energy and peak demands that California's electricity sector can be expected to serve in 2050, given a range of assumptions about electrification of vehicles, buildings, and industry under scenarios that achieve economy-wide GHG goals?
- + What role can variable and energy-limited resources such as wind, solar, energy storage and demand response play in meeting long-run resource adequacy needs?
- + What mix of renewable resources, electric energy storage, and natural gas generation capacity would meet California's energy and resource adequacy needs at least cost through 2050 while achieving economy-wide GHG goals?
- + What is the role of natural gas generation capacity under scenarios that achieve deep decarbonization while preserving system reliability?
- + What infrastructure investments would be needed to preserve resource adequacy in California if natural gas generation capacity were eliminated entirely?

## **1.4 Report Contents**

The remainder of this report is organized as follows:

- + Section 2 provides an overview of the study approach and scenarios analyzed;
- + Section 3 describes the three models used in the study, including methodology and key assumptions;

- + Section 4 presents the results of the analysis for the study's primary scenarios;
- + Section 5 presents results for a variety of sensitivities examined; and
- + Section 6 presents the study's conclusions.

# 2 Modeling Approach and Key Assumptions

## 2.1 Reliability Standards

Electricity resource adequacy standards are established to ensure that sufficient resources are available to meet electric load under the broadest possible range of weather and resource outage conditions, subject to a standard for acceptable frequency of loss-of-load events. There is no single industry standard for resource adequacy, and approaches and standards vary considerably. The most robust approach to measure resource adequacy uses loss-of-load-probability (LOLP) modeling, which applies Monte Carlo or other statistical techniques to compare available generation and load across thousands of simulated years. The results of these studies are frequently used to establish a target planning reserve margin (PRM). The PRM is defined as the quantity of resources above the expected 1-in-2 (median) peak load forecast that would be required to meet the loss-of-load standard.<sup>6</sup> This approach is currently used in California, where the California Public Utilities Commission (CPUC) administers a resource adequacy (RA) program that requires each load serving entity (LSE) to procure sufficient capacity to meet a PRM of 15% above its expected 1-in-2 peak load on a monthly basis.

The concept and application of a PRM to measure resource adequacy has historically worked well in a paradigm in which most generation capacity is "firm": that is, each resource is available to dispatch to full capacity when called upon by an operator except in the event of unexpected forced outages. Under this paradigm, if the system has sufficient capability to meet its peak demand (plus some margin for extreme

<sup>&</sup>lt;sup>6</sup> 1-in-2 (median) denotes that half of the years have a peak load higher than this value and half of the years have a peak load that is lower

weather and unexpected outages), it will also be capable of serving load throughout the rest of the year. However, as the penetrations of variable (e.g., wind and solar) and use-limited (e.g., storage, hydro, demand response) resources increase, the application of a PRM to measure resource adequacy becomes increasingly challenging, and measuring the contribution of each resource towards a PRM target requires the use of increasingly sophisticated modeling techniques. Loss-of-load-probability modeling techniques, like the ones used for this study, are data-intensive and require significant computing power but are necessary to understand the reliability characteristics and dynamics of generation portfolios that rely heavily on variable and use-limited resources.

In this study, resource adequacy is measured directly through loss-of-load-probability modeling, and a system is judged to be sufficient based on the frequency and duration of reliability events. <sup>7</sup> Even in loss-of-load-probability modeling, there is no single uniform standard for sufficiency, and the commonly-referenced "1-day-in-10-year" standard has multiple possible interpretations. This study uses a reliability standard based on loss of load expectation (LOLE), a measure of the expected number of hours of unserved energy observed over the course of a year; the standard applied in this study is 2.4 hours per year (i.e., 24 hours over 10 years).<sup>8</sup>

### 2.2 Scenarios & Sensitivities

This study examines the long-term need for natural gas generation capacity within the context of California's aggressive decarbonization goals; that is, all scenarios and sensitivities examined in this report are consistent with the state's "80 by 50" economy-wide carbon goals.<sup>9</sup> Meeting deep decarbonization

<sup>&</sup>lt;sup>7</sup> This study only considers system level resource adequacy and does not look at local reliability events driven by transmission or distribution outages. <sup>8</sup> Other common interpretations include 1 event in 10 years or 1 hour in 10 years (0.1 hr/yr).

<sup>&</sup>lt;sup>9</sup> This study was completed before the release of Executive Order B-55-18 by Governor Jerry Brown establishing a statewide goal of carbon neutrality by 2045. Nevertheless, this study illustrates some of the challenges associated with completely decarbonizing the electricity sector, suggesting that measures from other sectors, including offsets, and/or fundamentally different technologies than the ones that are included in the study may be needed to meet the carbon neutrality goals cost-effectively.

goals will likely rely on strategies across all four foundational pillars. The degree to which each pillar will be needed will vary depending upon the pathway chosen; this, in turn, will have different implications for the electricity sector.

The study focuses on two primary scenarios, intended to represent bookends among the range of possible pathways to achieving the state's goals:

- + The <u>High Biogas</u> scenario includes electrification of light-duty passenger vehicles and some building end-uses but meets some building and other transportation energy demands with an expanded supply of renewable natural gas and decarbonized liquid fuels.
- + The <u>High Electrification</u> scenario relies predominantly on electrification of transportation and buildings to achieve state GHG goals. This scenario includes the widespread deployment of lightduty and heavy-duty vehicles and the electrification of space and water heating in buildings. Because of the higher electrification loads in this scenario, a higher GHG budget is allocated to the electricity sector within the economy-wide target.

This study also tests the sensitivity of the High Electrification scenario results to a wide range of key inputs and assumptions (Table 1).

Category	Sensitivity	
Resource Availability	- Low Import Availability	
	- High Out-of-State Wind	
	- High Geothermal	
	- High Flexible Loads	
Carbon Targets	- Low Carbon Target	
	- High Carbon Target	
Resource Costs	- Low Solar & Storage Costs	

#### Table 1. Sensitivities Analyzed on High Electrification Scenario

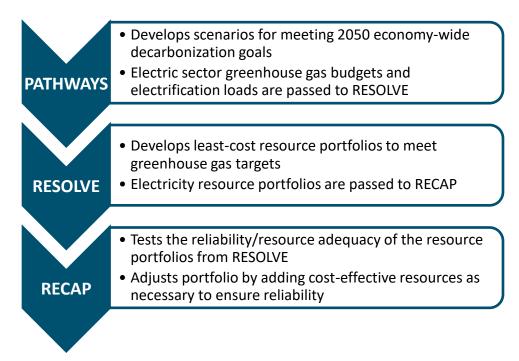
<ul> <li>High Going-Forward Natural Gas Generation Capacity Costs</li> </ul>
<ul> <li>Low Going-Forward Natural Gas Generation Capacity Costs</li> </ul>

## 2.3 Modeling Approach

This study relies upon three well-known E3 models of the California electricity system which have been used extensively by state agencies, utilities, and stakeholders to examine similar questions. These models are used in sequence to develop generation portfolios consistent with the state's climate goals and then to measure the reliability of those portfolios, making adjustments as necessary to ensure resource adequacy. The RESOLVE and RECAP models, including methodology and assumptions, are explained indepth in the Appendix. The PATHWAYS methodology is documented in detail in the CEC decarbonization study,<sup>10</sup> and major assumptions are highlighted in this section.

<sup>&</sup>lt;sup>10</sup> Available at: <u>https://efiling.energy.ca.gov/GetDocument.aspx?tn=223785</u>

#### Figure 2. E3's Three-Model Approach



## 2.4 California PATHWAYS Model

#### 2.4.1 MODEL OVERVIEW

The California PATHWAYS Model is an economy-wide energy and greenhouse gas accounting model developed by E3 to create carbon-compliant policy scenarios across multiple economic sectors. It is a long-horizon, technology-specific scenario model that has been modified and improved over time in collaboration with the California Energy Commission, the California Air Resources Board, and other California stakeholders. PATHWAYS includes a detailed representation of the buildings, industry, transportation, and electricity sectors and explicitly models stocks and replacement of buildings, building equipment, appliances, and vehicles. Demand for energy is driven by forecasts of population, building

square footage, and other energy service needs. PATHWAYS outputs electricity demand and greenhouse gas emissions for each year through 2050.

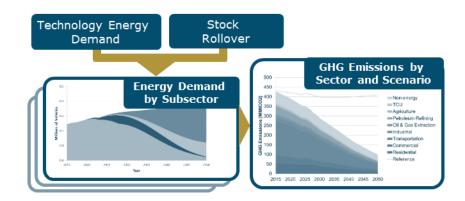


Figure 3: PATHWAYS Overview Diagram

This project relies heavily on the PATHWAYS model version used for the CEC deep decarbonization project. For a detailed description of the model and input assumptions, please see the full CEC report documentation.<sup>11</sup>

#### 2.4.2 KEY ASSUMPTIONS

PATHWAYS inputs and assumptions used in this study are largely based on those used in the CEC deep decarbonization project. The two scenarios used in this analysis are branched from the "No Hydrogen Scenario" developed for the CEC study but with differences in the degree of reliance on electrification vs. biofuels as decarbonization strategies. The key assumptions that distinguish the High Electrification and High Biogas scenarios from one another are shown in Table 2.

<sup>&</sup>lt;sup>11</sup> <u>https://efiling.energy.ca.gov/GetDocument.aspx?tn=223785</u>

	2050 Metric		
Assumption	High Electrification Scenario	High Biogas Scenario	
<b>Building Efficiency</b> <i>Reduction in building demand relative to 2015</i>	34%		
<b>Building Electrification</b> Electrification of natural gas end uses	Nearly 100%	50-75% <sup>12</sup>	
Light Duty Vehicle Electrification Percent of stock	96%		
<b>Truck Electrification</b> Percent of heavy-duty truck stock	44%	3%	
Industry Efficiency Reduction in non-petroleum energy demand relative to 2015	22%		
Industry electrification Percent of natural gas consumption	20-100% <sup>13</sup>	0%	
Advanced biofuel utilization Million dry tones of biomass	48	91	

#### Table 2. Key Assumptions in PATHWAYS Scenarios

## 2.5 Renewable Energy Solutions (RESOLVE) Model

#### 2.5.1 MODEL OVERVIEW

RESOLVE is a resource investment model that identifies optimal long-term generation and transmission investments in an electricity system, subject to reliability, technical, and policy constraints. RESOLVE has

<sup>&</sup>lt;sup>12</sup> 50% in commercial buildings; 75% in residential buildings.

<sup>&</sup>lt;sup>13</sup> 20% of process heating; 30% of miscellaneous end-uses; 100% of boilers.

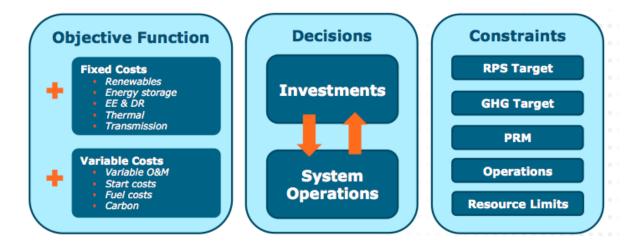
been used extensively in high profile studies in multiple jurisdictions including California, Hawaii, the Pacific Northwest, the Desert Southwest, the Upper Midwest, and Canada. In this study, it is used to develop least-cost resource portfolios for California that meet various decarbonization and renewable energy targets.

This study utilizes the California-wide RESOLVE version that was developed for the CEC's deep decarbonization project to evaluate long-run (2050) electricity portfolios for the state. A separate version of RESOLVE has been used by the California Public Utilities Commission (CPUC) to evaluate near-term (2030) optimal resource portfolios for the CAISO footprint within the context of the CPUC's Integrated Resource Planning (IRP) proceeding.<sup>14</sup> The principal differences between the models are the footprint (state of California vs. CAISO area) and the time frame (2050 vs. 2030) over which resource investment is optimized.

RESOLVE considers both the fixed and operational costs of different portfolios over the lifetime of the resources and is specifically designed to simulate power systems operating under high penetrations of renewable energy and electric energy storage. By co-optimizing investment and operations decisions in one stage, the model directly captures dynamic trade-offs between them, such as energy storage investments vs. renewable curtailment/overbuild. The model uses weather-matched load, renewable and hydro data and simulates interconnection-wide operations over a representative set of sample days in each year. The objective function minimizes net present value (NPV) of electricity system costs, which is the sum of fixed investment costs and variable plus fixed operating costs, subject to various constraints. Figure 4 provides an overview of the model.

<sup>&</sup>lt;sup>14</sup> http://cpuc.ca.gov/General.aspx?id=6442457210

#### Figure 4. Overview of RESOLVE Model



RESOLVE's optimization capabilities allow it to select from among a wide range of potential new resources. In general, the options for new investments considered in this study are limited to those technologies that are commercially available today. This approach ensures that the greenhouse gas reduction portfolios developed in this study can be achieved without relying on assumed future technological breakthroughs. The full range of resource options considered by RESOLVE in this study is shown in Table 3 below.

#### Table 3. Resource Options Considered in RESOLVE

Candidate Resource Option	Examples of Available Options	Functionality
Natural Gas Generation	<ul> <li>Simple cycle gas turbines</li> <li>Reciprocating engines</li> <li>Combined cycle gas turbines</li> </ul>	<ul> <li>Dispatches economically based on heat rate, subject to ramping limitations</li> <li>Contributes to meeting reserve requirements and ramping needs</li> </ul>
Renewable Generation	<ul> <li>Geothermal</li> <li>Wind (inc. Out-of-State)</li> <li>Utility Scale Solar PV (inc. Out-of-State)</li> <li>Distributed Solar PV</li> </ul>	<ul> <li>Variable generation generates as available; geothermal assumed to run as baseload</li> <li>Dynamic downward dispatch of variable renewable resources to help balance load</li> </ul>
Energy Storage	<ul> <li>Batteries (&gt; 1 hour)</li> <li>Pumped hydro storage (&gt; 12 hours)</li> </ul>	<ul> <li>Stores excess energy for later dispatch</li> <li>Contributes to meeting reserve requirements and ramping needs</li> </ul>
Flexible Loads	<ul> <li>Advanced shift demand response (e.g., controllable AC)</li> </ul>	<ul> <li>Allows the model to shift load from one timepoint to another</li> </ul>

E3 has recently added two features to RESOLVE to help answer some of the key questions about maintaining reliability under high renewables:

- + Economic Retirements: This logic allows RESOLVE to retire existing resources if the going-forward costs of maintaining the resources is greater than the fuel, O&M, ancillary service and capacity savings the resources produce when operating.
- + Seasonal Energy Sufficiency Requirement: This constraint ensures the system can produce sufficient energy across extended periods (up to 3 weeks) and anomalous periods of low renewable output that are not captured in the limited set of sample days used for operations in the model. In most electricity systems today, which meet significant shares of demand with firm

resources that can be dispatched throughout the year when needed, this type of constraint is not significant. However, in a system that relies heavily on intermittent renewables, the capability to serve load during prolonged periods of low renewable output is a key reliability consideration.<sup>15</sup>

It is worth noting that RESOLVE is not designed to answer detailed resource adequacy questions in systems without sufficient firm capacity. The RESOLVE modeling framework is limited to a set of representative sample days which don't contain enough data points to make robust conclusions on reliability events that happen infrequently (potentially less than once per year). In addition, the sample days are independent (i.e., not connected) and therefore do not capture the potential need for multi-day or seasonal storage. This type of long-duration storage could be extremely important in a system without sufficient firm capacity. RESOLVE does include a Planning Reserve Margin constraint to ensure that sufficient resources are maintained to meet an assumed long-run reliability standard, but the PRM standard is developed exogenously and incorporated into RESOLVE as an assumption. For this reason, the RESOLVE analysis is supplemented with a detailed reliability analysis using RECAP as described in Section 2.6.

#### 2.5.2 KEY ASSUMPTIONS

The electricity sector loads and GHG targets for both the High Biogas and High Electrification scenarios from PATHWAYS are passed to RESOLVE in order to develop optimal resource portfolios to meet 80% GHG reduction targets by 2050 reliably and at least cost. Both scenarios, including loads and carbon targets, are described in detail in Section 3.

<sup>&</sup>lt;sup>15</sup> The seasonal energy sufficiency constraint used in RESOLVE is not meant to serve as a substitute for more detailed loss-of-load-probability reliability analysis (as is done in RECAP). This constraint is included in RESOLVE as a proxy for such detailed analysis, but the analysis ultimately tests all portfolios with the RECAP model and adds additional resources for reliability if needed.

This study generally uses the same RESOLVE modeling assumptions as the CEC deep decarbonization study. Notable additional assumptions that were applied in RESOLVE to both the High Biogas and High Electrification scenarios are listed in Table 4 below.

Category		CEC Study Assumption	Assumption for This Study
Costs	Natural gas fixed O&M	N/A	Going-forward cost to maintain existing natural gas generation set to \$50/kW-yr. <sup>16</sup>
	Renewable and battery storage costs	2016 National Renewable Energy Lab (NREL) Annual Technology Baseline (ATB), and Lazard Levelized Cost of Storage v2.0	Updated to be consistent with the 2018 National Renewable Energy Lab (NREL) Annual Technology Baseline (ATB), and Lazard Levelized Cost of Storage v3.0. See Appendix for details.
Candidate Resource Limits	Solar PV	Limited to 266,963 MW in-state and 45,684 MW out-of-state (UT/NV/NM/AZ)	Same
	Wind	Limited to 2,586 MW in- state and 70,000 MW out-of-state (WY/NM/PNW)	Limited to 2,586 MW in- state and 12,000 MW out- of-state (WY/NM/PNW)
	Geothermal	Limited to 1,808 MW in- state and 1,152 MW out-of-state (NV/PNW)	Same
	Pumped storage	Limited to 4,000 MW	Same
	Battery storage	Unlimited availability	Same
	Demand response	Up to 4.9 GW	Same
	CCS	Not available	Same

#### Table 4. Key RESOLVE Input Assumptions

<sup>16</sup> Loosely and conservatively based on the CEC Cost of Generation study: <u>https://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf</u>

	Biogas	Incremental cost of	Same
		\$33/MMBtu in 2050	
	Flexible loads	Limited to 55,000 MWh	Same
		of shift per day (double	
		the amount available in	
		the 2017 CPUC IRP).	
	RA imports	Limited to 10,000 MW	Same
		for resource adequacy	
		purposes	
Other	RPS target	50% by 2030 (SB 350	60% by 2030, 100% by
		compliant)	2045 (SB 100 compliant)
	EV charging flexibility	By 2030, 90% of EV load	By 2030, 30% of EV load is
		is flexible, and 25% of EV	flexible, and 25% of EV
		owners have access to	owners have access to
		workplace charging	workplace charging
	Behind-the-meter PV	Baseline installed	Same
		capacity of 15,335 MW	
		by 2030 and 24,742 MW	
		by 2050 (forced in).	
		Model can select up to	
		36,749 MW of	
		additional BTM PV.	

For a more detailed list of assumptions, including baseline resources, candidate resource costs, performance, and potential, please refer to the Appendix.

In addition, a set of sensitivities based on the High Electrification scenario are modeled. The table below shows an overview of the assumptions in each sensitivity. Results of these sensitivities are presented in Section 3.6.

Category	Sensitivity	Description
Resource Availability	Low Imports Availability	Decreases availability of imports for reliability from 10 GW to 0 GW
	High Out of State Wind	Increases availability of out-of-state wind (WY/NM/PNW) from 12 GW to 22 GW
	High Geothermal	Doubles geothermal availability from 3 GW to 6 GW
Resource Costs	Low Solar and Storage Costs	Reduces solar & storage costs to low end of NREL ATB and Lazard projections, respectively; reduces 2030 solar fixed costs by 24% (vs. 2030 reference) and Li-ion battery fixed costs by 20% (vs. 2030 reference)
	Low Going-Forward Gas Maintenance Costs	Decreases going-forward cost to maintain existing gas generation from \$50/kW-yr to \$10/kW-yr
	High Going-Forward Gas Maintenance Costs	Increases going-forward cost to maintain existing gas generation from \$50/kW-yr to \$100/kW-yr
Carbon Targets	Lower Carbon Target	Reduces 2050 electricity sector carbon target from 9.8 MMT CO2e/yr to 3 MMT CO2e/yr
	Higher Carbon Target	Increases 2050 electricity sector carbon target from 9.8 MMT CO2e/yr to 12 MMT CO2e/yr

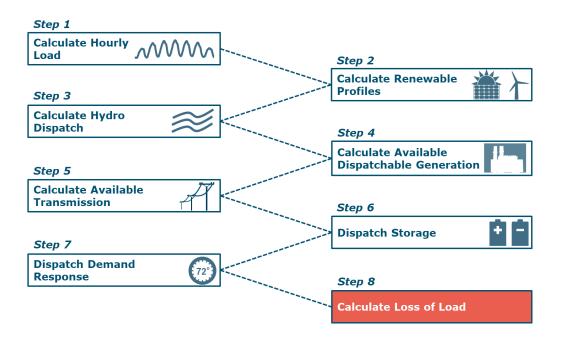
## 2.6 Renewable Energy Capacity Planning (RECAP) Model

#### 2.6.1 MODEL OVERVIEW

The portfolios developed in RESOLVE are tested for resource adequacy in RECAP, a loss-of-load-probability model developed by E3. RECAP has been used extensively to test the reliability of electricity systems across North America, including in California, Hawaii, Canada, the Pacific Northwest, the Desert Southwest, the Upper Midwest, and Florida.

RECAP calculates LOLE by simulating the electricity system with a specific set of generating resources and loads under a wide variety of weather years, renewable generation years, and stochastic forced outages of electric generation resources and imports on transmission. By simulating the system thousands of times with different combinations of these factors, RECAP provides a statistically significant estimation of LOLE.

RECAP was specifically designed to calculate the reliability of electricity systems operating under high penetrations of renewable energy and storage. Correlations within the model capture linkage between load, weather, and renewable generation conditions. Time-sequential simulation tracks the state of charge for energy-limited dispatchable resources such as hydro, energy storage, and demand response. An overview of the RECAP modeling process is shown below in Figure 5.



#### Figure 5: Overview of RECAP Model

RECAP is used to evaluate the reliability of resource portfolios produced by RESOLVE and improve them by adding resources when the reliability is insufficient (i.e., where LOLE exceeds 2.4 hrs/yr).

## **3 Results**

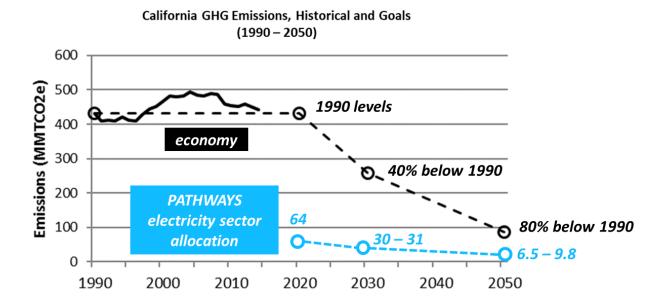
### **3.1 Economy-Wide Decarbonization Pathways**

E3's PATHWAYS model identifies technology adoption scenarios to meet economy-wide GHG targets by balancing the cost of emissions reductions between different economic sectors. It is important to note that the model does not perform optimization and that each of the scenarios presented below is the result of E3 user input. The model does, however, output costs that allows the user to observe how costs change between different decarbonization pathways.

As the following figures illustrate, both the High Biogas and High Electrification scenarios achieve 80% economy-wide GHG reductions by 2050 through different pathways as described in the methods and assumptions section. Because more energy services are provided by the electricity sector in the High Electrification scenario, a slightly higher emissions budget is allocated to the electricity sector in the High Electrification (9.8 MMT  $CO_2e/yr$ ) scenario as compared to the High Biogas (6.5 MMT  $CO_2e/yr$ ) scenario.

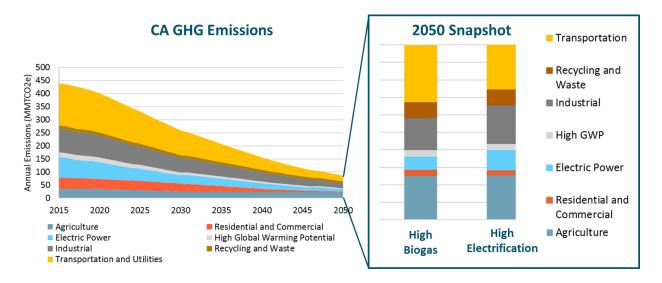
Notably, in both the High Biogas and High Electrification scenarios, electricity sector loads are roughly flat through 2030 due to significant investment in energy efficiency that counteracts natural load growth. Post-2030, electric loads begin to grow substantially as electrification measures kick in. Growth in loads by sector and scenario are shown in Figure 8. The electric loads and annual carbon targets shown in Table 7 are then passed to the RESOLVE model as described in the table below.





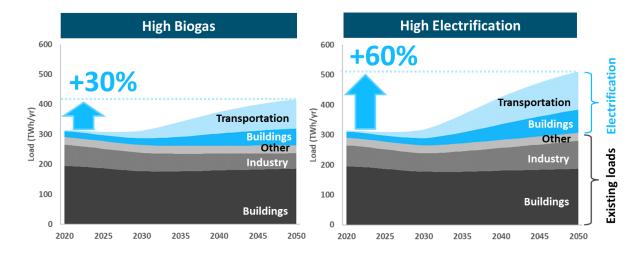
### Table 6. 2050 GHG Emissions by Sector (MMT CO2e)

Sector	2015 Historical	2050 High Biogas	2050 High Electrification
Agriculture	36.3	21.6	21.8
Electric Power	80.4	6.5	9.8
High Global Warming Potential Gasses	17.9	3.1	3.1
Industrial	92.4	15.8	19.0
Recycling & Waste	10.7	7.9	7.9
Residential & Commercial	40.6	3.1	2.6
Transportation	160.6	28.1	21.9
Total	438.9	86.2	86.2



### Figure 7: Reduction in GHG Emissions by Sector Through 2050

Figure 8: Load Forecasts by Scenario



	Annual Energy (TWh)		Gross Peak Load <sup>17</sup> (GW)		Annual Carbon Target (MMT CO2e)	
	High Electrification	High Biogas	High Electrification	High Biogas	High Electrification	High Biogas
2020	315	315	65	65	64	64
2030	317	312	63	63	32	31
2040	426	374	79	72	21	17
2050	511	417	93	78	9.8	6.5

### Table 7: Load Forecast and Carbon Budget by Scenario

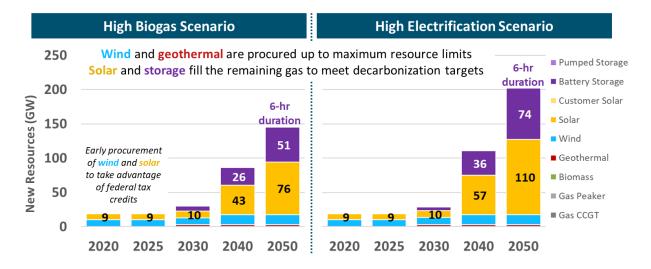
## 3.2 Electricity Generation Portfolios

To meet the deep decarbonization targets applied to the electricity sector in both the High Biogas and High Electrification cases, RESOLVE selects significant quantities of solar and storage (Figure 9). The maximum allowable quantities of 12 GW of out of state wind generation and 3 GW of geothermal are also selected, highlighting their diversity value.<sup>18</sup> Due to this large quantity of renewables and storage, both of these scenarios also achieve greater than 100% carbon free energy for compliance with SB 100 as described in Section 1.1.

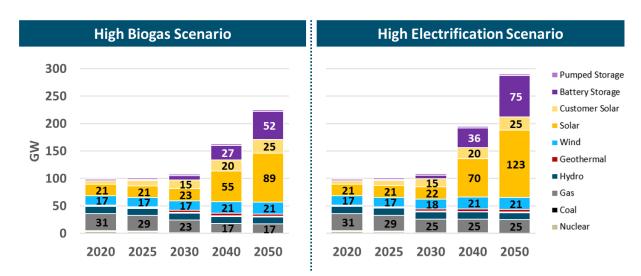
<sup>&</sup>lt;sup>17</sup> Peak load shown in this table does not include the impact of flexible load shifting. Flexibility increases absolute peak load because it shifts load into the middle of the day when the solar resource is at full output. More information on flexible loads is provided in Section 4.9. Gross peak load does not include behind-the-meter solar PV which would reduce it if it were included.

<sup>&</sup>lt;sup>18</sup> If given more geothermal or wind generation potential, the model generally picks more of them even though they are generally more expensive per MWh of generation than solar PV. The reason is that the system is already oversaturated with solar generation during the daytime, so the value of any generation during solar generation times is zero or very low while generation at other times (night-time and generally in winter) is very valuable.

### **Figure 9. New Build Selected Resources Results**

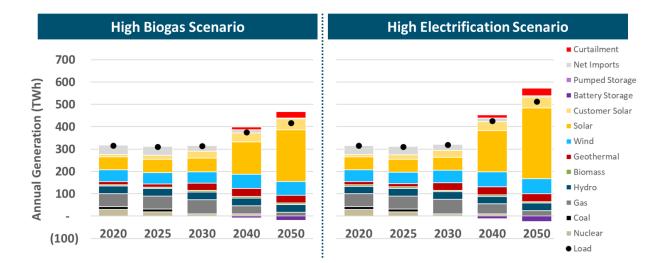


The resulting total portfolio of resources (i.e., the sum of both the existing and planned resources and the future selected resources) is shown in Figure 10. The magnitude of the selected future resources dwarfs the installed capacity of the existing and planned baseline resources on the system. The total amount of installed capacity on the system more than doubles from 2020 to 2050 in both scenarios. This occurs because renewables and energy storage are only partly effective at meeting resource adequacy needs, and the portfolios therefore require additional amounts of backup capacity. The next section discusses the role of the remaining gas generation in more detail. A detailed table of the selected resources and the total portfolio is shown in Appendix B.



#### **Figure 10. Total Resource Portfolio Results**

Despite the retention of natural gas generation capacity for reliability, the utilization of the gas fleet (and gas-fired imports) declines precipitously through 2050 as shown in Figure 11, leading to significant reductions in greenhouse gas emissions.

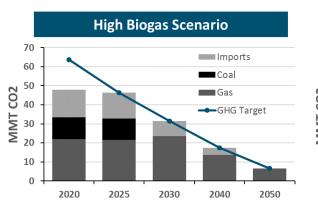


#### **Figure 11: Total Generation Results**

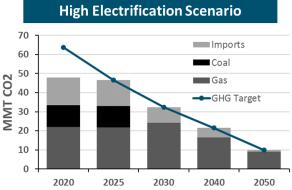
These quantities are part of the least cost portfolio of resources that help to meet both 80% economywide GHG reductions as well as the SB100 carbon-free energy goal. As explained in Section 1.1, greater than 100% RPS is possible despite the use of natural gas generation because California generates enough zero-carbon electricity during the year to offset 100% of retail sales. Some of that energy is exported during hours when California has more than it needs, and an equivalent amount of electricity is generated with natural gas or imported during hours when California doesn't have enough zero-carbon energy supplies. This "netting" approach is consistent with the implementation of the RPS in California's electricity system today, and with how RPS compliance is measured in other jurisdictions throughout North America. The RPS production target is based on retail sales which is also approximately 7% lower than total generation due to transmission and distribution losses, which further allows for limited use of natural gas or other non-RPS resources when needed for reliability.

## **3.3 Electricity Sector Emissions**

Both the High Biogas and High Electrification scenarios achieve the 2050 and interim GHG targets from the PATHWAYS results. The High Biogas scenario electricity sector emissions decline to 6.5 MMT CO2/yr and the High Electrification scenario electricity sector emissions decline to 9.8 MMT CO2/yr in 2050. Achieved emissions are lower than the GHG target in 2020 due to RESOLVE's early procurement of renewables to take advantage of federal tax credits.



### Figure 12: GHG Emissions by Scenario (Target and Achieved)



# 3.4 Resource Adequacy Summary

### 3.4.1 LOSS-OF-LOAD-PROBABILITY STATISTICS

Reliability statistics from the RECAP modeling for the High Biogas and High Electrification cases, compared against the 2018 system, are shown in Table 8. By the standard used in this study to measure reliability a maximum LOLE of 2.4 hours per year<sup>19</sup>—the two base case 2050 portfolios are deemed to be sufficiently reliable.

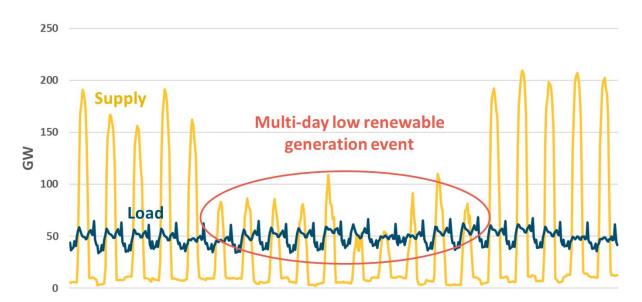
### Table 8. 2050 Portfolio Reliability Statistics

Metric	Units	2018 Historical	2050 High Biogas	2050 High Electrification
Loss of Load Expectation	Hours/yr	1.15	0.92	1.05
Loss of Load Frequency	Events/yr	0.25	0.16	0.13
Expected Unserved Energy	GWh/yr	2.8	10.1	8.6

<sup>&</sup>lt;sup>19</sup> California's current reliability construct with a 15% planning reserve margin yields better reliability than 2.4 hrs/yr as shown in the table.

### 3.4.2 DRIVERS OF RELIABILITY CHALLENGES

While the overall measure of reliability in the 2050 portfolios is comparable to the 2018 system, the types and nature of reliability challenges in the 2050 systems are significantly different. Because most generation today is dispatchable, the biggest reliability driver is peak load events when there is some probability that available generation capacity may be insufficient. In a system where most generation is intermittent, loss-of-load events don't necessarily occur during high load conditions. Rather, the biggest driver is the potential for multi-day periods of low renewable production. During these events, renewable generation may be insufficient to serve all load and storage quickly depletes. In these instances, it is important to have some type of firm capacity that can be dispatched to fill the gap when renewables and storage cannot serve all load (Figure 13).



### Figure 13. Multi-Day Low Renewable Generation Event

This phenomenon is demonstrated in Figure 14, which shows that over one simulation based on 68 years of weather, loss of load events are highly correlated with the 3-day running average of solar generation.

These events are relatively rare and represent much more than simple cloud cover in a particular area; rather, they represent heavy cloud cover over significant portions of the Western U.S. combined with low wind production for an extended period of time. These events may only occur a few times per decade.

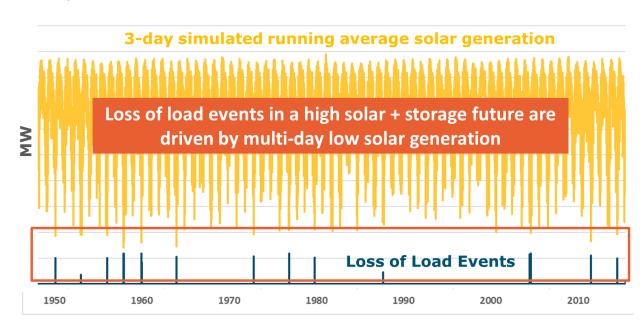
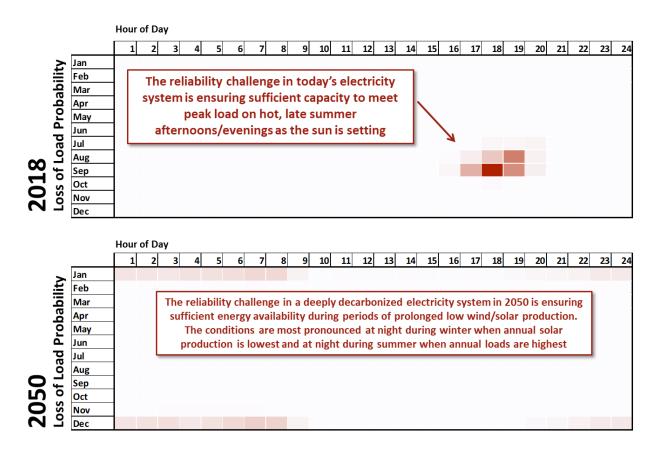


Figure 14: Multi-Day Solar Generation and Loss of Load Correlation for High Solar + Storage Electricity System

Because solar generation is generally much lower in the winter than the summer, these multi-day low solar generation events are most likely to occur in the winter, particularly December and January when solar generation is lowest. When these conditions do occur, loss of load is most likely to occur during non-daylight hours when there is no solar generation and the system is reliant upon energy storage which is not fully charged. Figure 15 compares the occurrence of loss-of-load-probability in 2018 by month-hour with the occurrence in the 2050 High Electrification scenario. In the 2018 system, loss of load probability is generally coincident with system peak demands, which occur in the late afternoon during the summer months of July, August and September. In the 2050 decarbonization scenarios, the occurrence of loss of

load probability shifts away from the summer period and into the winter, and the most challenging period for reliability in 2050 occurs during the nighttime of winter months.





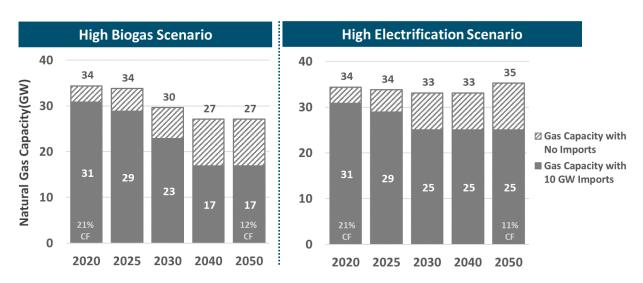
It is interesting to note that a system with reliability events most likely to occur during cold winter nights is a paradigm shift from California's electricity system today, where reliability events are most likely to occur on hot summer afternoons and evenings.

### 3.4.3 ROLE OF NATURAL GAS GENERATION

The significant buildout of renewables and storage to meet decarbonization targets contributes to resource adequacy so that not all existing natural gas generation capacity is needed. Therefore, RESOLVE retires some gas capacity in the 2020s to reduce costs. However, despite the very large quantities of storage in both base case scenarios (51 GW to 74 GW), the model retains 17 GW to 25 GW of natural gas generation capacity for reliability. The model retains natural gas generation capacity to meet the reliability challenge described in Section 3.4.2 to serve load for the limited number of times when renewable generation is low over a multi-day or multi-week period.

These base case scenario results include the assumption that the state can import 10 GW for reliability at all times, which is consistent with today's planning assumptions<sup>20</sup> and broadly consistent with the notion that the winter-peaking Northwest has available capacity in the summer when California needs it the most. However, there is significant uncertainty about the availability of imports going forward, particularly as loads grow, coal generation retires, and regional loads become more coincident with one another. If import availability is reduced to 0 GW in 2050, the need for in-state natural gas generation capacity increases on a one-for-one basis to between 27 GW and 35 GW.

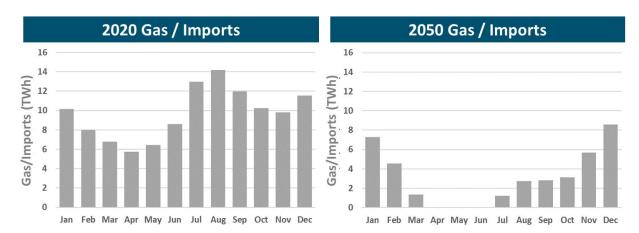
<sup>&</sup>lt;sup>20</sup> See CPUC Scenario Tool: <u>http://www.cpuc.ca.gov/General.aspx?id=11681</u>



### Figure 16. Remaining Gas Generation in the High Biogas and High Electrification Scenarios

While significant quantities of natural gas generation capacity are retained for reliability, the utilization of these remaining gas resources changes substantially over time. In the 2020 system, gas generation is utilized on a daily basis throughout the year to provide energy and essential grid services for reliability. In 2050, there are many days in which no natural gas generation operates, and the fleetwide capacity factor is reduced to 11% in the High Electrification scenario and 12% in the High Biogas scenario. Runtime for the gas fleet is constrained by the carbon budget derived from PATHWAYS. Figure 16 shows how the fleet-wide natural gas capacity factor declines from 21% to 12% from 2020 to 2050 in the high electrification scenario, and Figure 17 shows a distribution of gas and gas-fired import generation<sup>21</sup> by month in 2020 and 2050.

<sup>&</sup>lt;sup>21</sup> All non-specified electricity imports are assumed to come from natural-gas fired generation in the Western Interconnection, an assumption consistent with existing GHG accounting procedures at the California Air Resources Board.



### Figure 17: Monthly Gas and Import Energy in 2020 and 2050 (High Electrification Scenario)

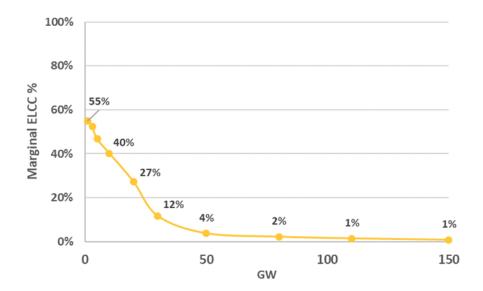
A key conclusion of this study is that keeping an installed base of natural gas generation capacity to generate energy when need during periods of low wind and solar generation can be consistent with deep decarbonization goals as long as sufficient renewables and storage are also built to reduce gas plant utilization. When renewables and storage can meet grid needs (at close to zero marginal cost), the gas fleet is not dispatched. RESOLVE's carbon target ensures that total emissions don't exceed what is needed to keep California on track to meet its climate goal.

### 3.4.4 EFFECTIVE LOAD CARRYING CAPABILITY RESULTS

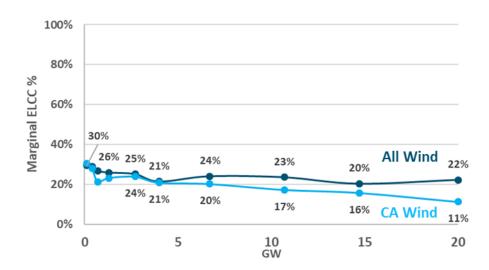
Effective load carrying capability (ELCC) is the quantity of "perfect capacity" that could be replaced or avoided with renewables or storage while providing equivalent system reliability. These results demonstrate the substitutability of renewables and storage with dispatchable firm capacity in California. A value of 50% means that the addition of 100 MW of that resource could displace the need for 50 MW of firm capacity without compromising reliability.

As demonstrated in the following charts, solar, wind, and storage can provide ELCC to substitute for firm capacity but do not do so on a 1-for-1 basis and have a diminishing contribution to system reliability as

more of each resource is added. Both 4- hour and 10-hour energy storage systems are modeled. The value of 10-hour storage decays less rapidly, but both durations have similar marginal capacity value beyond 20 GW of cumulative installed capacity. This is intuitive given that both durations are significantly shorter than multi-day storage that would be needed to ride through the primary reliability challenges as illustrated in Section 3.4.2.

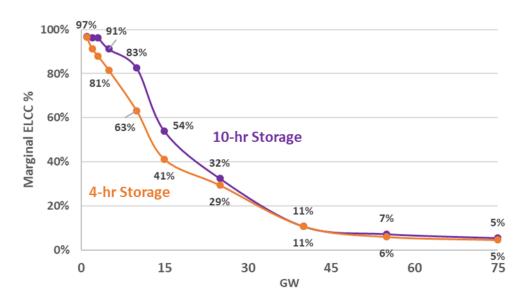


### Figure 18: Solar ELCC in 2050 (High Electrification Scenario)

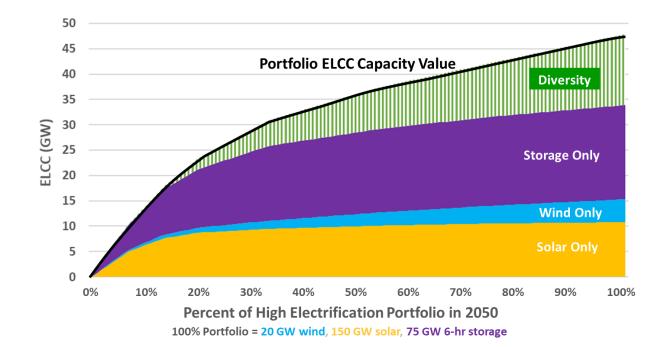


### Figure 19: Wind ELCC in 2050 (High Electrification Scenario)





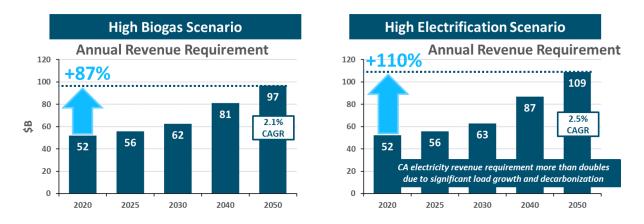
It is important to note that while renewable resources and electric energy storage are limited in their ability to provide firm capacity on their own, they do have interactive effects which increases their combined contribution to reliability. For example, an increase in solar penetration pushes the system net load peak from the afternoon into the evening when wind generation is generally higher. Further, solar provides the energy that storage needs to provide capacity while storage provides the integration that solar needs to provide capacity. This concept is referred to as the diversity benefit. However, despite this diversity benefit, nearly 250 GW of installed renewables and storage capacity is required to achieve an ELCC of 47 GW in the High Electrification scenario, as illustrated in Figure 21.





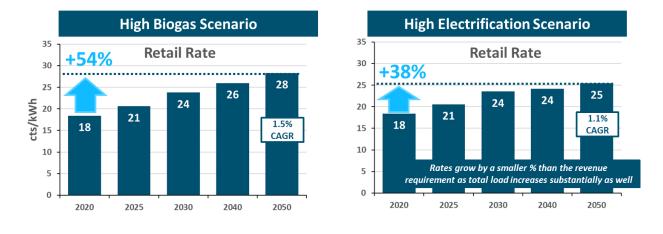
## 3.5 Electricity System Costs

In both the High Biogas and High Electrification scenarios, the total cost of the electricity sector (revenue requirements) increases substantially. This is due both to load growth as well as the substantial investment in renewables and storage required to meet decarbonization targets. In the High Electrification case, the total cost of electricity grows more due to higher load growth.



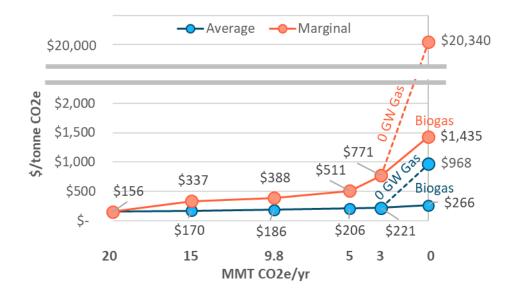
### Figure 22: Annual Cost of California Electricity (Revenue Requirement)

Due to load growth, the average retail rate (total cost / electricity sales) does not increase as substantially as total cost in percentage terms. Rather, retail rates increase roughly 40%-50% in real terms between 2020 and 2050. This represents less than 2% real escalation per year through 2050.



### Figure 23: Retail Electricity Rates

The average cost of carbon abatement (relative to a carbon unconstrained scenario) is roughly \$186/tCO2e in the 9.8 MMT High Electrification scenario and \$221/tCO2e in the 3 MMT Low Carbon sensitivity to the High Electrification scenario, while the marginal cost of carbon abatement is \$388/tCO2e and \$771/tCO2e, respectively. Figure 24 illustrates the increasing marginal and average cost of carbon abatement. Two results are shown for the 0 MMT CO<sub>2</sub>e/yr case. The Biogas case achieves reliability by allowing biogas to be combusted in natural gas generating plants (thus reinforcing the benefit of retaining natural gas generation infrastructure) while the 0 GW gas case achieves reliability by retiring all natural gas generation capacity and overbuilding solar and battery storage. The 0 GW gas case is highlighted in Section 3.6.

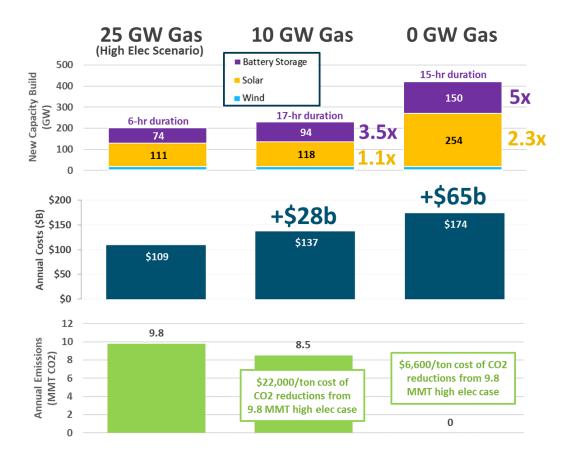


### Figure 24: High Electrification Cost of Carbon Abatement

## 3.6 Effect of Forced Gas Retirements

In the High Biogas and High Electrification scenarios, 17 GW and 25 GW of natural gas generation capacity are retained for reliability in 2050, respectively. This is the quantity of gas capacity that minimizes total cost of electric service while reducing carbon emissions to 6 and 10 MMT, respectively. Forcing additional gas generation to retire and replacing the capacity it provides with renewables and storage is extremely costly. Gas generation capacity can be dispatched when most needed by the grid. Replacing natural gas generation capacity with additional intermittent renewables and storage requires one or both of the following approaches: (1) oversizing the renewable generation so that it can serve load even when solar and wind production are low; (2) significantly increasing the duration of energy storage so that it can ride through periods of low renewable generation without completely discharging. Oversizing renewables generally entails significant renewable curtailment under normal conditions. Significantly increasing storage duration is prohibitively expensive given current technology.

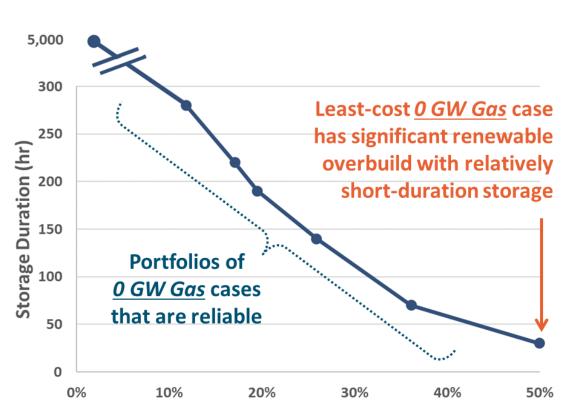
Using a combination of the RESOLVE and RECAP models, E3 created portfolios of resources that would be required to maintain acceptable resource adequacy if gas were to be retired below the 25 GW optimal capacity in the high electrification scenario. Reducing gas generation capacity to 10 GW requires a 3.5x increase in storage build due to a tripling of duration and a 25% increase in charge/discharge capacity. Retiring all gas (and gas-fired imports) requires a 5x increase in storage build due to more than doubling both the duration and charge/discharge capacity as well as a 2.3x increase in new solar build. Reducing gas generation capacity to 10 GW and 0 GW increases costs by \$28 billion annually and \$65 billion annually, respectively.



### Figure 25: Effect of Forced Gas Retirements (High Electrification Scenario)

In the 0 GW gas or imports case, the resulting 2.3x increase in solar capacity results in approximately 50% annual curtailment of all renewable energy production. RECAP chooses this level of renewable overbuild along with 15 hours of storage as the most economic portfolio of resources to provide reliable electric service. It is important to note that in this scenario the model builds significantly more storage charge/discharge capacity than peak load for the purpose of being able to absorb the additional solar energy on the system. Because the 150 GW of discharge capacity is higher than peak load, the 15-hour duration effectively more than triples in duration to 45 hours since the largest observed storage discharge in any hour is 43 GW due to other resources being available to serve the peak load.

As shown in Figure 26, there are, however, alternative portfolios of solar and storage that could also provide reliable service with 0 GW of gas by increasing the duration of storage and decreasing renewable overbuild. With today's commercial technology, increasing the duration of storage is technically feasible but impractically expensive since the cost of the storage scales nearly linearly with duration. However, potential future breakthroughs in energy storage technology may result in optimal portfolios that entail longer duration storage (and less renewable overbuild).





**Renewable Curtailment %** 

# **4 Sensitivity Analysis**

Several potential key drivers were identified throughout the analysis and explored for their impact on the optimal quantity of natural gas generation capacity retained by the model. All sensitivity analysis was conducted on the High Electrification scenario. This section also explores the potential for flexible loads to substitute for natural gas generation capacity.

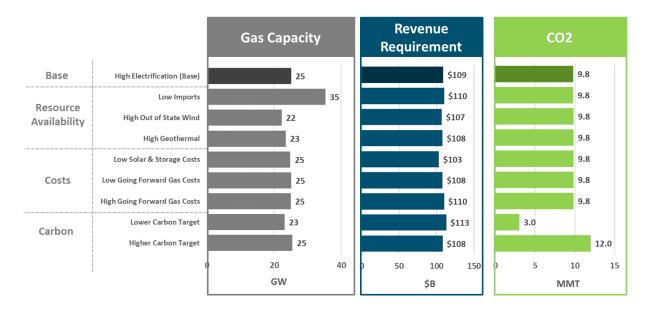
### **Table 9: Description of Sensitivity Cases**

Category	Sensitivity	Description
Resource Availability	Low Imports Availability	Decreases availability of imports for reliability from 10 GW to 0 GW
	High Out of State Wind	Increases availability of out-of-state wind (WY/NM/PNW) from 12 GW to 22 GW
	High Geothermal	Doubles geothermal availability from 3 GW to 6 GW
Resource Costs	Low Solar and Storage Costs	Reduces solar & storage costs to low end of NREL ATB and Lazard projections, respectively; reduces 2030 solar fixed costs by 24% (vs. 2030 reference) and Li-ion battery fixed costs by 20% (vs. 2030 reference)
	Low Going Forward Gas Maintenance Costs	Decreases going forward to maintain existing gas generation from \$50/kW-yr to \$10/kW-yr
	High Going Forward Gas Maintenance Costs	Increases going forward to maintain existing gas generation from \$50/kW-yr to \$100/kW-yr
Carbon Targets	Lower Carbon Target	Reduces 2050 electricity sector carbon target from 10 MMT CO2e/yr to 3 MMT CO2e/yr
	Higher Carbon Target	Increases 2050 electricity sector carbon target from 10 MMT CO2e/yr to 12 MMT CO2e/yr

In general, the results show that the quantity of natural gas generation capacity retained to meet resource adequacy needs at lowest cost is relatively insensitive to many potential key drivers. In other words, while

solar and storage can substitute for some amount of natural gas generation capacity, at high penetrations, the physical tradeoffs become sufficiently challenging that the optimal amount of substitution is relatively insensitive to the assumed costs or availability of resources. The one clear exception to this is the impact of reduced availability of firm imported electricity. Because imports are represented as a reliable source of capacity in the model, they are very substitutable for natural gas generation capacity. In fact, the results show that the model retains additional natural gas generation capacity on a one-for-one basis as import availability decreases.

The retained natural gas generation capacity, annual revenue requirement, and annual CO2 emissions for each of the sensitivity cases is shown in Figure 27. Because there is binding carbon constraint in 2050, all cases achieve the same carbon emissions unless the target is explicitly different.

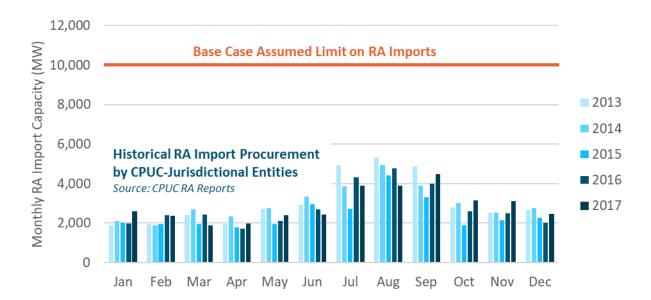


### Figure 27: Sensitivity Analysis 2050 Summary Results

Brief commentary on each of the cases is provided below.

# 4.1 Import Availability

Both the High Biogas and High Electrification scenarios assume the availability of 10 GW of imports for resource adequacy purposes, assumed to be available at all times of the year. This assumption is generally consistent with assumptions used in the CPUC's Integrated Resource Planning proceeding, as well as other assessments of the state's ability to import power during peak periods. However, there is considerable uncertainty in the state's ability to rely on imports for resource adequacy purposes, and the current degree to which load serving entities (LSEs) rely on imports to meet resource adequacy (RA) requirements is considerably lower than the long-term planning assumptions used by the CPUC (Figure 28). While there are many factors that influence an LSE's decision whether to meet RA needs with in-state resources or imports, one important dynamic to consider is that tightening reserve margins and changing load profiles in neighboring regions may limit the availability of imports for RA to levels below the physical limits of the transmission system.



### Figure 28. Comparison of Assumed RA Import Limits with Actual Levels of Procurement by CPUC-Jurisdictional Entities

California's ability to secure imports to meet its reliability needs is directly tied to the future resource needs within the state. Given the level of uncertainty, this study includes a sensitivity that assumes no imports are available for resource adequacy purposes, requiring all resource adequacy needs to be met with resources within the state. To the extent that import availability is lower than the assumed 10 GW, the optimal quantity of natural gas generation capacity would increase approximately 1-for-1.

Metric		Units	Base Case	Low Import Availability Case	Change
Installed	Gas	MW	25,025	35,264	10,239
Capacity	Geothermal	MW	4,516	4,516	-
	Hydro	MW	13,204	13,204	-
	Solar	MW	147,399	147,482	83
	Wind	MW	21,438	21,438	-
	Storage	MW	77,938	77,839	(99)
Renewable 0	Curtailment	%	12.20%	12.20%	0.00%
Revenue Rec	Revenue Requirement		\$109	\$110	\$1
Carbon Emis	Carbon Emissions		9.8	9.8	-
Loss of Load	Expectation	hrs/yr	0.91	0.91	

### Table 10. Low Import Availability Sensitivity Metrics

## 4.2 High Out-of-State Wind

The high out-of-state wind sensitivity increases the potential available wind in New Mexico and Wyoming from 12 GW to 22 GW. The model selects all the incremental capacity provided, indicating the high value of resource diversity to California. The main drivers of this value are its low cost and relative lack of correlation with solar, which drives reliability events when production is low. Because of this natural production diversity from solar, particularly during the winter, wind is an extremely valuable resource that can reduce costs and reduce the required quantity of other installed capacity needed for reliability. While offshore wind was not examined in this analysis, it is likely that it would provide similar value to the system.

Metric		Units	Base Case	High Out- of-State Wind Case	Change
Installed	Gas	MW	25,025	22,205	(2,820)
Capacity	Geothermal	MW	4,516	4,516	-
	Hydro	MW	13,204	13,204	-
	Solar	MW	147,399	133,056	(14,343)
	Wind	MW	21,438	31,438	10,000
	Storage	MW	77,938	64,144	(13,794)
Renewable C	Curtailment	%	12.20%	11.50%	-0.7%
Revenue Requirement		\$BB/yr	\$109	\$107	-\$2
Carbon Emissions		MMTCO2e	9.8	9.8	_
Loss of Load	Expectation	hrs/yr	0.9	0.6	-0.3

### Table 11. High Out-of-State Wind Sensitivity Metrics

## 4.3 High Geothermal

Like the high out-of-state wind sensitivity, all incremental geothermal capacity provided in this sensitivity (3 GW) is selected by the model. A relatively small amount of baseload geothermal energy (3 GW) can avoid large amounts of solar (9 GW) and storage (6 GW) due to its higher capacity factor and diversity benefits. Since geothermal energy can provide firm capacity, it also enables an additional 1.6 GW of natural gas generation capacity retirements. These retirements aren't 1-for-1 with the installed

geothermal capacity since the geothermal scenario also has fewer solar and storage resources due to its higher capacity factor (80-85% as compared to 30-35% for solar resources).

Metric		Units	Base Case	High Geothermal Case	Change
Installed	Gas	MW	25,025	23,413	(1,612)
Capacity	Geothermal	MW	4,516	7,476	2,960
	Hydro	MW	13,204	13,204	-
	Solar	MW	147,399	138,569	(8,830)
	Wind	MW	21,438	21,438	-
	Storage	MW	77,938	71,611	(6,327)
Renewable	Curtailment	%	12.20%	11.50%	-0.70%
Revenue Re	Revenue Requirement		\$109	\$108	\$(1)
Carbon Emis	Carbon Emissions		9.8	9.8	_
Loss of Load	Expectation	hrs/yr	0.9	0.6	-0.3

### Table 12. High Geothermal Sensitivity Metrics

## 4.4 Low Solar & Storage Costs

The low solar and storage costs sensitivity uses the low end of the 2018 NREL ATB<sup>22</sup> and Lazard Levelized Cost of Storage Version 3.0<sup>23</sup> solar and storage costs and the most aggressive cost reduction trajectories. This reduces 2030 solar fixed costs by 24% and 2030 battery fixed costs by about 20%.<sup>24</sup> Surprisingly, this has very little impact on the portfolio as the model selects 3 GW of incremental solar, 1 GW of incremental

<sup>&</sup>lt;sup>22</sup> https://data.nrel.gov/files/89/2018-ATB-data-interim-geo.xlsm

<sup>&</sup>lt;sup>23</sup> https://www.lazard.com/perspective/levelized-cost-of-storage-2017/

<sup>&</sup>lt;sup>24</sup> Costs beyond 2030 are assumed to be flat in real terms

storage, and 2 GW less of wind. This lack of change is because the model already was selecting solar and storage to meet decarbonization goals. The minimal change in renewable procurement leads to essentially no change in the retained quantity of natural gas generation capacity. Again, this largely has to do with the fact that at high penetrations of solar and storage, it is difficult to replace natural gas generation capacity with solar and storage without significantly overbuilding the solar or adding very long duration storage. The lower technology costs do have a significant impact on the overall cost of the electricity portfolio.

Metric		Units	Base Case	Low Solar & Storage Cost	Change
Installed	Gas	MW	25,025	24,786	(239)
Capacity	Geothermal	MW	4,516	4,516	-
	Hydro	MW	13,204	13,204	-
	Solar	MW	147,399	150,400	3,001
	Wind	MW	21,438	19,685	(1,753)
	Storage	MW	77,938	78,624	686
Renewable C	Curtailment	%	12.20%	12.70%	0.50%
Revenue Rec	Revenue Requirement		\$109	\$103	\$(6)
Carbon Emis	Carbon Emissions		9.8	9.8	_
Loss of Load	Expectation	hrs/yr	0.9	0.9	_

### Table 13. Low Solar & Storage Cost Sensitivity Metrics

## 4.5 High Going-Forward Gas Costs

The high going-forward gas costs sensitivity increases the fixed cost of maintaining existing natural gas generation from \$50/kW-yr to \$100/kW-yr. The model can avoid these costs by retiring natural gas

generation capacity. This change has essentially no impact on the quantity of procured solar, storage, or the retained quantity of natural gas generation capacity. In short, the cost of the resources to replace the characteristics of the gas fleet is sufficiently expensive such that the model will incur the extra cost to retain the gas fleet which increases total system costs by a small amount.

Metric		Units	Base Case	High Going- Forward Cost	Change
Installed	Gas	MW	25,025	24,949	(76)
Capacity	Geothermal	MW	4,516	4,516	-
	Hydro	MW	13,204	13,204	-
	Solar	MW	147,399	147,562	163
	Wind	MW	21,438	21,438	-
	Storage	MW	77,938	77,906	(32)
Renewable C	Curtailment	%	12.20%	12.20%	0.00%
Revenue Requirement		\$BB/yr	\$109	\$110	\$1
Carbon Emissions		MMTCO2e	9.8	9.8	_
Loss of Load	Expectation	hrs/yr	0.9	0.9	_

### Table 14. High Going-Forward Gas Cost Sensitivity Metrics

## 4.6 Low Going-Forward Gas Costs

The low going-forward gas costs sensitivity decreases the cost of maintaining existing natural gas generation capacity from \$50/kW-yr to \$10/kW-yr. The model can avoid these costs by retiring gas generation. This has no impact on the portfolio since the solar and storage in the high electrification case are procured for carbon reductions. To the extent that these resources are fundamentally substitutable for natural gas, the model retires gas to avoid the cost of maintenance, be it \$50/kW-yr or \$10/kW-yr.

Metric		Units	Base Case	Low Going- Forward Cost	Change
Installed	Gas	MW	25,025	25,066	41
Capacity	Geothermal	MW	4,516	4,516	-
	Hydro	MW	13,204	13,204	-
	Solar	MW	147,399	147,329	(70)
	Wind	MW	21,438	21,438	-
	Storage	MW	77,938	77,723	(215)
Renewable C	Curtailment	%	12%	12%	0%
Revenue Requirement		\$BB/yr	\$109	\$108	-\$1
Carbon Emis	Carbon Emissions		9.8	9.8	_
Loss of Load	Expectation	hrs/yr	0.9	0.5	-0.4

### Table 15. Low Going-Forward Gas Cost Sensitivity Metrics

# 4.7 Lower Carbon Target (3 MMT)

The low carbon sensitivity decreases the 2050 carbon target from 9.8 MMT CO2e/yr to 3 MMT CO2e/yr. To achieve this reduction the model builds an additional 18 GW of solar and 7 GW of storage. However, due to the limited substitutability of these additional resources and natural gas generation capacity, the model still retains 23 GW of gas capacity, only 2 GW less than in the base High Electrification scenario.

Metric		Units	Base Case	Lower Carbon Target	Change
Installed	Gas	MW	25,025	23,080	(1,945)
Capacity	Geothermal	MW	4,516	4,516	-
	Hydro	MW	13,204	13,204	-
	Solar	MW	147,399	165,039	17,640
	Wind	MW	21,438	21,438	-
	Storage	MW	77,938	84,980	7,042
Renewable C	urtailment	%	12.20%	16.40%	4.20%
Revenue Req	Revenue Requirement		\$109	\$113	\$4
Carbon Emiss	Carbon Emissions		9.8	3.0	-6.8
Loss of Load	Expectation	hrs/yr	0.9	0.3	-0.6

### Table 16. Lower Carbon Target Sensitivity Metrics

# 4.8 Higher Carbon Target (12 MMT)

The higher carbon target sensitivity explores the impact of increasing the 2050 carbon target from 9.8 MMT CO2e to 12 MMT CO2e. This increase in emissions target led to a slightly smaller solar & storage build which decreased system costs, but very little change in the quantity of gas generation selected to maintain reliability.

Metric		Units	Base Case	Higher Carbon Target	Change
Installed	Gas	MW	25,025	25,439	414
Capacity	Geothermal	MW	4,516	4,516	-
	Hydro	MW	13,204	13,204	-
	Solar	MW	147,399	144,429	(2,970)
	Wind	MW	21,438	21,438	-
	Storage	MW	77,938	74,082	(3,856)
Renewable C	Curtailment	%	12.20%	11.80%	-0.40%
Revenue Rec	Revenue Requirement		\$109	\$108	\$(1)
Carbon Emis	Carbon Emissions		9.8	12.0	2.2
Loss of Load	Expectation	hrs/yr	0.91	0.91	

### Table 17. Higher Carbon Target Sensitivity Metrics

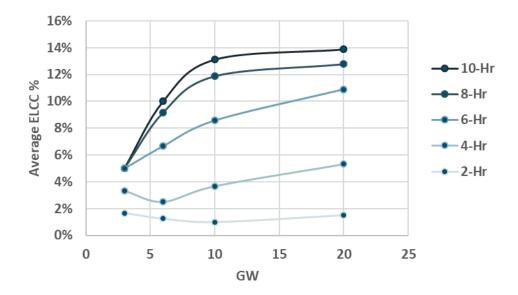
# 4.9 Flexible Load Analysis

Flexible loads represent a relatively nascent and untapped potential resource for California going forward that has been the subject of recent research.<sup>25</sup> "Flexible" electric loads are those that can potentially be moved to better align with system capability or economics, such as when solar or wind energy is generating. Flexible loads do not reduce the total quantity of electricity demand, just the timing of electricity demand. This can provide significant value to the grid in terms of being able to avoid short-duration storage that would otherwise need to be procured to integrate solar production with electricity demand.

<sup>&</sup>lt;sup>25</sup> http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452698

However, for the same reasons that it is difficult for short-duration storage to substitute for natural gas generation capacity, it is also difficult for flexible loads. Many flexible loads can move electricity demand within the day but cannot move it across days or weeks as the system would require to provide reliability during multi-day periods of low solar and wind generation. The chart below shows that even 20 GW of flexible loads that can move energy +/- 10 hours only provide 15% of its nameplate capacity (i.e., 3 GW of equivalent firm natural gas generation capacity). Therefore, this study shows that while flexible loads do have the potential to provide economic and environmental benefits to California, they are not easily substitutable for dispatchable natural gas generation capacity.





# **5** Conclusions

This study demonstrates that it is possible to maintain resource adequacy for a deeply decarbonized California electricity system that is heavily dependent on renewables and electric energy storage as long as sufficient firm capacity is available for periods of sustained low solar production. In addition, the study shows that an electricity system with firm natural gas generation capacity is consistent with achieving least-cost, economy-wide GHG reductions of 80% below 1990 levels by 2050. Specific key findings are listed below:

## 5.1 Key Findings

- The least-cost plan for achieving the 2050 economy-wide goal of GHG reductions of 80% below 1990 levels for California requires electricity sector GHG emissions to be reduced to very low levels by 2050: between 6 and 10 million metric tons, or 90-95% below 1990 levels.<sup>26</sup>
  - Achieving economy-wide goals <u>does not require complete decarbonization</u> of electricity supply.
- Some form of <u>firm generation capacity</u> is needed to ensure reliable electric load service on a deeply decarbonized electricity system.

<sup>&</sup>lt;sup>26</sup> 1990 California electricity generation emissions total 111 MMT CO2e GHG. Source: https://www.arb.ca.gov/cc/inventory/pubs/reports/staff\_report\_1990\_level.pdf

- Firm generation capacity refers to electric energy resources that can produce energy on demand during extended periods of time in which wind and solar energy are not available.
- Natural gas generation capacity is currently the most economic source of firm capacity. The least-cost electricity portfolio to meet the 2050 economy-wide GHG goals for California includes <u>17-35 GW of natural gas generation capacity</u> for reliability. This firm capacity is needed even while adding very large quantities of solar and electric energy storage.
- + A firm fuel supply is required to ensure that natural gas generation capacity can produce electricity when needed.
- Alternative technologies can reduce the need for firm natural gas generation capacity but have significant limitations.
  - Wind, solar, energy storage and demand response can contribute to resource adequacy but, at high penetrations, have important limitations in their ability to substitute for firm capacity.
  - + Geothermal energy provides firm capacity and is selected up to the state's assumed technical potential, but that potential is limited.
  - + Biogas or carbon-neutral gas is considered in this study but not selected for electricity generation due to higher-value applications in other sectors. Selection of biogas for electricity generation would not change the study's conclusions about the need for firm capacity to maintain electric reliability; in fact, the biogas would likely use the same fuel delivery and electric generation infrastructure as is used for fossil natural gas generation in this study.
  - + Other low-carbon alternatives to natural gas generation capacity for maintaining resource adequacy at scale are not considered in this study. These include nuclear,

fossil generation with carbon capture and storage, and renewables with ultra-long duration energy storage.

- 4. It would be <u>extremely costly and impractical</u> to replace all natural gas generation capacity with solar, wind and storage, due to the very large quantities of these resources that would be required.
- 5. The findings are robust to all key sensitivity drivers. Between 15 and 33 GW of gas capacity is retained even under an electric sector carbon budget as low as 3 million metric tons by 2050.

# Appendix A. RESOLVE Model Documentation

As discussed in the main body of this report, assumptions are consistent with the public 2018 CED Deep Decarbonization model unless specified otherwise.<sup>27</sup> That version, in turn, relies on assumptions developed for the 2017 CPUC IRP RESOLVE version released on September 19, 2017.<sup>28</sup> This section highlights key assumptions as well as any assumptions that have been updated since the 2017 IRP modeling effort.

# A.1 Baseline Resources

### A.1.1 OVERVIEW

Within RESOLVE, a portion of the generation fleet is specified exogenously, representing the resources that are assumed to be existing over the course of the analysis; these "Baseline Resources" are included by default in the portfolio optimized by RESOLVE. The set of Baseline Resources generally includes (1) existing generators, net of expected future retirements; (2) specific future generation resources with sufficient likelihood to include for planning purposes; and (3) generic future resources needed to meet policy and reliability targets <u>outside</u> of California.

An overview of the assumed installed capacity for California's Baseline Resources is shown in Table 18 below. The next section provides further information on the sources and assumptions used for the Baseline Resources, broken out by (1) conventional resources, (2) renewable resources, (3) hydro

<sup>&</sup>lt;sup>27</sup> https://efiling.energy.ca.gov/GetDocument.aspx?tn=223785

<sup>&</sup>lt;sup>28</sup> <u>http://cpuc.ca.gov/irp/proposedrsp/</u>

resources, (4) storage resources, (5) demand response, (6) hydrogen electrolysis loads, and (7) flexible EV charging. For more background on these resources, please consult the data and documentation released during the 2017 CPUC IRP Process.<sup>29</sup>

Category	Resource Class	2020	2030	2040	2050
	СНР	72	72	72	72
	Coal	1,800	1,800	—	—
	Nuclear	3,379	2,229	1,079	_
	CCGT1	17,768	17,768	17,768	17,221
	CCGT2	2,974	2,974	2,974	2,974
Thermal	Peaker1	9,974	9,974	9,974	9,351
merma	Peaker2	2,762	2,632	2,632	2,632
	Advanced CCGT	—	—	—	—
	Aero CT	—	_	_	_
	Reciprocating engine	263	263	263	263
	ST	652	652	652	652
	Total	37,844	34,892	34,865	33,093
Firm	Geothermal	1,894	1,858	1,858	1,858
Renewable*	Biomass	1,146	1,146	1,146	1,146
	Wind	6,853	6,853	6,853	6,853
Variable Renewables*	Utility-scale solar PV	12,505	12,823	12,823	12,823
	Behind-the-meter PV	5,821	15,335	20,002	24,742
Hydro	Hydro**	12,610	12,610	12,610	12,610
Storage	Pumped storage***	3,049	3,049	3,049	3,049
Storage	Storage mandate****	478	478	478	478
DR	Shed Demand Response	1,752	1,752	1,752	1,752

### Table 18. California Baseline Resources Installed Capacity (MW) by Year

<sup>29</sup> Available here: <u>http://cpuc.ca.gov/irp/proposedrsp/</u>

Category	Resource Class	2020	2030	2040	2050
Hydrogen	Hydrogen electrolysis capacity	79	138	264	349
Electric Vehicles	Flexible EV charging	N/A	N/A	N/A	N/A

\*Excludes resources located outside of California but under long-term contract to California LSEs. Note that these resources are accounted for in the RPS constraint.

\*\*Includes a share of Hoover's total generating capability (2,080 MW) in proportion to California's ownership shares: CAISO (38.3%) and LADWP (17.6%).

\*\*\*Eastwood, Helms, Lake Hodges, San Luis, and Castaic.

\*\*\*\* For the storage mandate batteries, only includes what is installed up until now. The model decides whether it wants to select additional storage. Storage mandate batteries are assumed to be utility-controlled and dispatched to minimize system costs.

#### A.1.2 CONVENTIONAL RESOURCES

The Baseline Conventional Resources<sup>30</sup> included in the portfolio of the California load serving entities is derived from the preliminary 2017 CAISO NQC List.<sup>31</sup> The data from the NQC list is supplemented with additional information from the CAISO Master Generating Capability List<sup>32</sup>, the TEPPC 2026 Common Case, and the CARB Scoping Plan. This is generally consistent with the assumptions used in the 2017 CPUC IRP and the CEC deep decarbonization project. It is worth noting the assumption that CHP plants retire 25 years after their commission date, which results in almost no CHP plants online after 2020.

### A.1.3 RENEWABLE RESOURCES

Baseline Renewable Resources include both (1) existing resources under contract to California LSEs, and (2) resources currently under development. This information is compiled from multiple sources, including the CPUC IOU Contract Database, the CEC POU Contract reports, and the CEC Statewide Renewable Net Short spreadsheet.

<sup>&</sup>lt;sup>30</sup> Any non-renewable, thermal resource is referred to as conventional generation.

<sup>&</sup>lt;sup>31</sup> The preliminary 2017 CAISO NQC list was posted August 26, 2016, and is available here: <u>http://www.caiso.com/Documents/</u>2017NetQualifyingCapacity-ResourceAdequacyResources.html

<sup>&</sup>lt;sup>32</sup> The CAISO Master Generating Capability List used in this analysis represents known CAISO resource information as of November 2, 2016.

### A.1.4 LARGE HYDRO RESOURCES

The Baseline Large Hydro Resources in each region are the same as those used in the 2017 CPUC IRP (after aggregating CAISO, LADWP and BANC) and are assumed to remain unchanged over the timeline of the analysis.

### A.1.5 STORAGE RESOURCES

The existing pumped storage resources in CA are based on the CAISO 2017 NQC list; the storage capability of each facility, in MWh, is based on input assumptions in CAISO's 2014 LTPP PLEXOS database, resulting in a total of 300,825 MWh.<sup>33</sup> Note that although this number is large, the capability to store energy beyond 12 hours is not directly captured in RESOLVE given the dispatch window of one day at a time. The benefit of long-duration storage however is captured in the seasonal energy sufficiency constraint, as well as in the detailed reliability assessment in RECAP. The storage mandate installed capacity is based on CPUC data on recent installations.

#### A.1.6 DEMAND RESPONSE

RESOLVE treats the IOUs' existing shed demand response programs as prescribed Baseline Resources (i.e., forced into the model); the assumed peak load impact for each utility's programs are based on each utility's proposed demand response program ("Reliability & Economic Programs") in the 2018-2022 funding cycle. These assumptions are consistent with the assumptions in the 2017 CPUC IRP proceeding. DR in non-CAISO LSEs is assumed to be negligible.

<sup>&</sup>lt;sup>33</sup> This includes non-CAISO pumped storage facilities in California such as LADWP's Castaic plant.

### A.1.7 HYDROGEN ELECTROLYSIS LOAD

RESOLVE includes functionality to add hydrogen electrolysis loads with flexible operations. Given the annual electrolysis load and the electrolyzer installed capacity, the model will optimize hourly hydrolyzer operations to minimize costs, subject to the annual load and maximum capacity constraints. Table 19 shows the assumptions used in this study; the electrolyzer capacity, which is an exogenous model input, is oversized by a factor of 4 such that it can generate its annual budget while only running 1/4<sup>th</sup> of the day, mainly during the daytime when there is plenty of solar overgeneration. It is worth noting that the size of the hydrogen electrolysis load in this study is very small compared to the total annual load (<0.2%), making its effect on the overall results negligible.

### **Table 19. Hydrogen Electrolysis Load Assumptions**

Inputs	2020	2030	2040	2050
Electrolyzer Installed Capacity (MW)	79	138	264	349
Annual Hydrogen Electrolysis Load (GWh)	174	302	579	764

### A.1.8 FLEXIBLE EV CHARGING LOAD

Electric Vehicle charging can be modeled endogenously in RESOLVE, allowing the model to optimize the charging schedule, subject to constraints on charging availability, charging capacity, and driving demand. This study assumes that 10% of the EV fleet in 2020 can be charged flexibly this way, increasing to 30% by 2030, and staying at 30% thereafter.<sup>34</sup> This study also assumes that 8% of the EV fleet has access to (daytime) work-place charging, increasing to 25% in 2030, and staying at 25% thereafter. The resulting demand by each subcategory of EV loads is shown in Table 20 below.

<sup>&</sup>lt;sup>34</sup> The other 70% is assumed to be non-managed and is assigned a fixed shape, peaking at around 9 AM when people get to work and around 7 PM when people get home.

EV Charging Demand (GWh)	2020	2030	2040	2050
Flexible EV Charging Demand	167	5,361	15,480	19,319
Home Charging Only	153	4,020	11,610	14,489
Home and Work Charging	14	1,340	3,870	4,830
Inflexible EV Charging Demand	1,503	12,508	36,120	45,077
Home Charging Only	1,377	9,381	27,090	33,808
Home and Work Charging	125	3,127	9,030	11,269

### Table 20. Flexible EV Charging Demand Assumptions

Given California's solar-heavy renewable portfolios, the model tends apply the flexible charging mainly during the day-time (if work-place charging is available), when there is plenty of solar generation available, or during low demand times in the middle of the night (if no work-place charging is available).

# A.2 Candidate Resources

### A.2.1 NATURAL GAS

RESOLVE includes multiple technology options for new natural gas generation of varying costs and efficiencies. The natural gas resource classes available to the model and their respective all-in fixed costs, derived from E3's 2014 review of capital costs for WECC, *Capital Cost Review of Power Generation Technologies*,<sup>35</sup> are shown in table below. This cost includes all costs, except variable O&M and fuel costs.

<sup>&</sup>lt;sup>35</sup> Available at: https://www.wecc.biz/Reliability/2014 TEPPC Generation CapCost Report E3.pdf

Resource Class	Capital Cost (\$/kW)	Fixed O&M Cost (\$/kW-yr)	All-In Fixed Cost (\$/kW-yr)
CAISO_Advanced_CCGT	\$1,300	\$10	\$202
CAISO_Aero_CT	\$1,250	\$12	\$197
CAISO_Reciprocating_Engine	\$1,250	\$12	\$197

### Table 21. All-in Fixed Costs for Candidate Natural Gas Resources (\$/kW-yr)

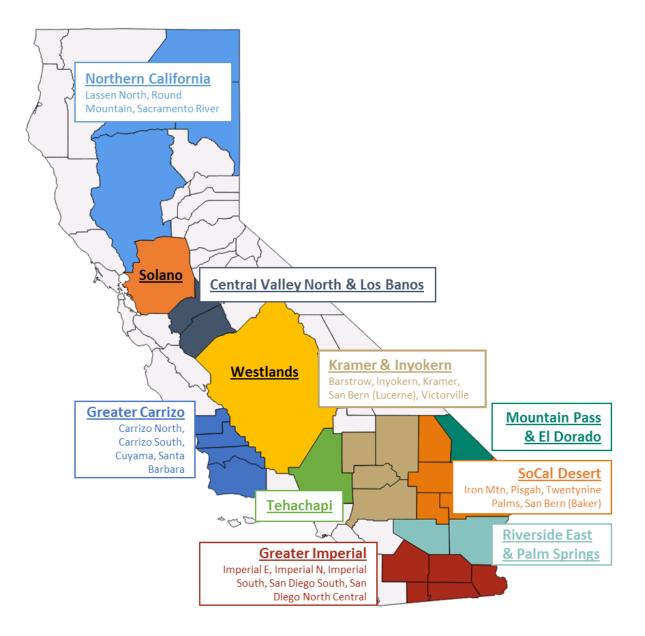
### A.2.2 RENEWABLES

Assumptions on the cost, performance, and potential of candidate renewable resources are based primarily on data developed by Black & Veatch for the CPUC's RPS Calculator v.6.3.<sup>36</sup> Black & Veatch used geospatial analysis to identify potential sites for renewable development in California and throughout the Western Interconnection. For input into RESOLVE, the detailed geospatial dataset developed by Black & Veatch is aggregated into "transmission zones." Within California, transmission zones are groupings of Competitive Renewable Energy Zones (CREZs). These groupings are shown in Figure 30.

The raw technical potential estimates developed by Black & Veatch are filtered through a set of environmental screens to produce the potential assumed available to RESOLVE. For this analysis, the DRECP/SJV screen was used. E3 found that the resulting renewable potential is not enough to meet the renewable targets in some scenarios, so the environmental screen's haircut for solar PV, which is very large and not necessarily linked to physical limits, was reduced by a factor of 4. The associated potential is summarized in Table 22.

<sup>&</sup>lt;sup>36</sup> Black & Veatch, *RPS Calculator V6.3 Data Updates*. Available at: <u>http://www.cpuc.ca.gov/uploadedFiles/CPUC Website/Content/</u><u>Utilities and Industries/Energy/Energy/Programs/Electric\_Power\_Procurement and Generation/LTPP/RPSCalc\_CostPotentialUpdate\_2016.pd</u> <u>f.</u> Note that although the data was developed with the intention of incorporating it into a new version of the RPS Calculator, no version 6.3 has been developed. This is because the IRP system plan development process is replacing the function previously served by the RPS Calculator.

### Figure 30. In-state Transmission Zones in RESOLVE



Туре	Resource	Renewable Potential (MW)
Biomass	In-State	_
Geothermal	Greater Imperial	1,384
	Northern California	424
	Subtotal, Geothermal	1,808
Solar	Central Valley North Los Banos	5,056
	Distributed	36,749
	Greater Carrizo	15,220
	Greater Imperial	36,572
	Mountain Pass El Dorado	17,367
	Northern California	248
	Riverside East Palm Springs	78,596
	Solano	14,339
	Southern California Desert	14,916
	Tehachapi	15,600
	Westlands	28,152
	Subtotal, Solar	266,963
Wind	Central Valley North Los Banos	146
	Distributed	253
	Greater Carrizo	1,095
	Greater Imperial	_
	Kramer Inyokern	_
	Northern California*	-
	Riverside East Palm Springs	42
	Solano	643
	Southern California Desert	_
	Tehachapi	407
	Subtotal, Wind	2,586

### Table 22. California Renewable Potential

\* Renewable potential for Northern California wind is set to zero across all screens due to both the unproven nature of the resource and expected obstacles in resource permitting.

The available potential for out-of-state resources is also based primarily on Black & Veatch's assessment of renewable resource potential that identifies high-quality resources in Western Renewable Energy Zones (WREZs), which are aggregated to regional bundles. These high-quality resources are assumed to require investments in new transmission to interconnect and deliver to California loads. These estimates of resource potential are supplemented with assumptions regarding the availability of lower-quality renewables that may be interconnected on the existing transmission system.

Contrasting the vast potential of out-of-state resources with the limited current development, E3 made a few adjustments for this study to take into account political, institutional and other non-physical barriers to out-of-state renewable and transmission development:

- Out-of-state solar development is limited to 15,000 MW each in Arizona, Utah, and Southern Nevada, and 664 MW in New Mexico, for a total of 45,664 MW.
- Out-of-state wind development on new transmission is limited to 5,000 MW of Wyoming wind and 5,000 MW of New Mexico wind, for a total of 10,000 MW. Note that there is an additional 2,000 MW available on existing transmission and 442 MW in Southern Nevada, which is interconnected directly with the CAISO system.

The final amount of renewable potential included is summarized in Table 23.

Туре	Resource	Renewable Potential (MW)
Geothermal	Pacific Northwest	832
	Southern Nevada	320
	Subtotal, Geothermal	1,152
Solar	Arizona	15,000
	New Mexico	664
	Southern Nevada	15,000
	Utah	15,000
	Subtotal, Solar	45,664
Wind	Arizona	-
	Idaho	-
	New Mexico (Existing Tx)	500
	New Mexico	5,000
	Pacific Northwest (Existing Tx)	1,500
	Pacific Northwest	-
	Southern Nevada	442
	Utah	-
	Wyoming	-
	Subtotal, Wind	12,442

### Table 23. Out-of-state Renewable Potential

The primary source for cost and performance assumptions of renewable generation was developed by Black & Veatch for the RPS Calculator v.6.3 in early 2013.<sup>36</sup> This information has been supplemented by an additional analysis conducted by E3 to update the cost of solar PV, since market data suggests a notable reduction in the cost of these resources since Black & Veatch's assessment. The source for these costs updates is the 2018 NREL Annual Technology Baseline.

The assumptions for renewable resources used in RESOLVE are shown in Table 24 and Table 25 for instate and out-of-state resources, respectively. The input to RESOLVE is an assumed levelized fixed cost (\$/kW-yr) for each resource; this is translated into the levelized cost of energy (\$/MWh) in Table 24 and Table 25 for comparability with typical Power Purchase Agreements (PPA) entered into between utilities and third-party developers. These costs include the effects of the federal Production Tax Credit (PTC) and the Investment Tax Credit (ITC).

Туре	Resource	Capacity	Levelized	Cost of Er	nergy (2016	\$/MWh)
		Factor	2020	2030	2040	2050
Geothermal	Greater Imperial	88%	\$92	\$92	\$92	\$92
	Northern California	80%	\$89	\$89	\$89	\$89
Solar	Central Valley North Los Banos	30%	\$53	\$67	\$67	\$67
	Distributed	23%	\$97	\$116	\$116	\$116
	Greater Carrizo	32%	\$49	\$61	\$61	\$61
	Greater Imperial	34%	\$46	\$58	\$58	\$58
	Kramer Inyokern	36%	\$44	\$55	\$55	\$55
	Mountain Pass El Dorado	34%	\$45	\$57	\$57	\$57
	Northern California	30%	\$52	\$66	\$66	\$66
	Riverside East Palm Springs	34%	\$46	\$58	\$58	\$58
	Solano	29%	\$53	\$67	\$67	\$67
	Southern California Desert	35%	\$45	\$57	\$57	\$57
	Tehachapi	35%	\$44	\$56	\$56	\$56
	Westlands	30%	\$51	\$65	\$65	\$65
Wind	Central Valley North Los Banos	31%	\$61	\$77	\$77	\$77
	Distributed	28%	\$92	\$107	\$107	\$107
	Greater Carrizo	31%	\$65	\$81	\$81	\$81
	Greater Imperial	31%	\$56	\$73	\$73	\$73
	Kramer Inyokern	32%	\$65	\$81	\$81	\$81
	Northern California	29%	\$70	\$85	\$85	\$85
	Riverside East Palm Springs	33%	\$63	\$79	\$79	\$79
	Solano	30%	\$64	\$80	\$80	\$80
	Southern California Desert	27%	\$70	\$86	\$86	\$86
	Tehachapi	33%	\$59	\$75	\$75	\$75

### Table 24. California Renewable Resource Cost & Performance Assumptions.

Туре	Resource	Capacity Factor	Levelized Cost of Energy (2016 \$/MWh)			2016
			2020	2030	2040	2050
Geothermal	Pacific Northwest	84%	\$84	\$84	\$84	\$84
	Southern Nevada	80%	\$107	\$107	\$107	\$107
Solar	Arizona	34%	\$38	\$51	\$51	\$51
	New Mexico	33%	\$39	\$52	\$52	\$52
	Southern Nevada	32%	\$46	\$59	\$59	\$59
	Utah	30%	\$45	\$60	\$60	\$60
Wind	Arizona	29%	\$62	\$78	\$78	\$78
	Idaho	32%	\$60	\$76	\$76	\$76
	New Mexico (Existing Tx)	36%	\$48	\$64	\$64	\$64
	New Mexico	44%	\$36	\$53	\$53	\$53
	Pacific Northwest (Existing Tx)	30%	\$73	\$88	\$88	\$88
	Pacific Northwest	32%	\$67	\$82	\$82	\$82
	Southern Nevada	28%	\$84	\$98	\$98	\$98
	Utah	31%	\$64	\$80	\$80	\$80
	Wyoming	44%	\$32	\$50	\$50	\$50

### Table 25. Out-of-state Renewable Resource Cost & Performance Assumptions

The lower solar cost sensitivity assumes a more aggressive cost reduction trajectory for solar (and storage), resulting in solar costs that are 24% lower in 2030.

### A.2.3 ENERGY STORAGE

The capital costs of candidate pumped storage and battery storage resources, shown in Table 26 below, are based on *Lazard's Levelized Cost of Storage v3.0* (2017).<sup>37</sup> Pumped storage costs are assumed to remain constant in real terms, while flow batteries and Li-ion batteries are assumed to have strong cost

<sup>&</sup>lt;sup>37</sup> Available at: https://www.lazard.com/perspective/levelized-cost-of-storage-2017/

reductions in the future. All scenarios use the "Mid" costs except for the "low storage and solar cost" sensitivity, which uses the "Low" costs.

This study assumes that there is unlimited resource potential for Li-ion and flow batteries, whereas pumped storage is limited to 4,000 MW, and only available by 2022 onwards.

Resource	Cost Component	Case	2020	2030	2040	2050
Li-lon Bottom	Levelized Fixed	Low	\$39	\$26	\$26	\$26
Battery	Cost – Power (\$/kW-yr)	Mid	\$44	\$31	\$31	\$31
	Levelized Fixed	Low	\$30	\$27	\$17	\$17
	Cost – Energy (\$/kWh-yr)	Mid	\$38	\$23	\$23	\$23
Flow	Levelized Fixed	Low	\$75	\$55	\$55	\$55
ватегу	Battery Cost – Power (\$/kW-yr)	Mid	\$152	\$116	\$116	\$116
	Levelized Fixed	Low	\$21	\$15	\$15	\$15
	Cost – Energy (\$/kWh-yr)	Mid	\$27	\$21	\$21	\$21
Pumped Storage	Levelized Fixed Cost – Power (\$/kW-yr)	Mid	\$146	\$146	\$146	\$146
	Levelized Fixed Cost – Energy (\$/kWh-yr)	Mid	\$12	\$12	\$12	\$12

### Table 26. Storage Resources Cost Assumptions<sup>38</sup>

<sup>&</sup>lt;sup>38</sup> The costs in this table include installation and interconnection; to get the total cost of a system, multiply the system's kWh rating with the energy cost and the system's kW rating with the power costs (i.e., both cost components are additive).

### A.2.4 DEMAND RESPONSE

This study uses the same assumption on cost, performance, and potential for shift and shed demand response as the 2017 CPUC IRP<sup>39</sup>, except for the potential of shift demand response which is doubled to reflect anticipated improvements in controllable loads driven by highly variable renewable generation. The size of each tranche of shift demand response is doubled while the cost is maintained the same. As a result, the model can select up the 55,000 MWh of daily shift demand response, with over half of that available at less than \$100/kWh-yr, and up to 4,900 MW of shed demand response, with over half that available at less than \$75/kW-yr. For more information, please consult the 2017 CPUC IRP RESOLVE Inputs and Assumptions document.

<sup>&</sup>lt;sup>39</sup> For more information on demand response, please consult the 2017 CPUC IRP RESOLVE Inputs and Assumptions document available at: http://cpuc.ca.gov/irp/proposedrsp/

# **Appendix B. Detailed RESOLVE Results**

# **B.1** High Biogas Scenario

Table 27. Selected Resources by Technology (High Biogas Scenario)

Selected Resources by Technology	Unit	2	020 202	5 2030	2040	2050
Geothermal	MW			2,640	2,960	2,960
Wind	MW	9,8	9,895	9,998	14,585	14,585
Wind_Offshore	MW			-	-	-
Solar	MW	8,5	32 8,532	9,887	42,676	76,496
Customer Solar	MW			-	-	-
Battery Storage	MW		- 1,023	3 7,241	26,043	51,092
Pumped Storage	MW			-	-	-
Energy Efficiency	MW			-	-	-
DR	MW			-	-	-
Flexible Load	MW			-	3,427	3,427
Hydrogen Electrolysis	MW		79 102	2 138	264	349

### Table 28. Total Installed Capacity by Technology (High Biogas Scenario)

Total Installed Capacity	Unit	2020	2025	2030	2040	2050
Nuclear	MW	3,379	2,229	1,079	1,079	-
СНР	MW	72	27	27	-	-
Coal	MW	1,800	1,800	-	-	-
Gas CCGT	MW	20,742	20,742	20,742	16,902	16,902
Gas Peaker	MW	10,066	8,073	2,140	-	-
Hydro	MW	12,610	12,610	12,610	12,610	12,610
Hydro (Small)	MW	595	595	595	595	595
Biomass	MW	787	787	787	787	787
Geothermal	MW	1,586	1,586	4,196	4,516	4,516
Wind	MW	16,748	16,748	16,851	21,438	21,438
Wind_Offshore	MW	-	-	-	-	-
Solar	MW	21,037	21,355	22,710	55,500	89,319
Customer Solar	MW	5,821	9,596	15,335	20,002	24,742
Battery Storage	MW	478	1,501	7,719	26,521	51,570
Pumped Storage	MW	3,049	3,049	3,049	3,049	3,049
Energy Efficiency	MW	-	-	-	-	-
DR	MW	1,752	1,752	1,752	1,752	1,752
Flexible Load	MW	-	-	-	3,427	3,427
Hydrogen Electrolysis	MW	79	102	138	264	349

### Table 29. Annual Generation by Technology (High Biogas Scenario)

Annual Generation	Unit	2020	2025	2030	2040	2050
Nuclear	GWh	29,597	19,523	9,450	9,450	-
СНР	GWh	626	237	237	-	-
Coal	GWh	12,541	12,317	-	-	-
Gas CCGT	GWh	56,157	56,388	63 <i>,</i> 308	37,219	17,365
Gas Peaker	GWh	1,117	791	62	-	-
Hydro	GWh	28,977	28,888	28,890	28,735	28,495
Hydro (Small)	GWh	5,211	5,211	5,211	5,211	5,211
Biomass	GWh	6,892	6,892	6,892	6 <i>,</i> 892	6 <i>,</i> 892
Geothermal	GWh	13,894	13,894	33,430	35,673	35,673
Wind	GWh	52,033	51,036	51,389	63 <i>,</i> 497	60,823
Wind_Offshore	GWh	-	-	-	-	-
Solar	GWh	57,485	58,531	61,492	145,008	230,974
Customer Solar	GWh	11,578	19,084	30,498	39,781	49,206
Battery Storage	GWh	6	(363)	(1,987)	(8,944)	(19,044)
Pumped Storage	GWh	(440)	(694)	(745)	(1,343)	(1,778)
Energy Efficiency	GWh	-	-	-	-	-
DR	GWh	-	9	9	-	-
Imports	GWh	42,001	39,972	26,777	16,921	8,521
Exports	GWh	(1,447)	(1,549)	(1,241)	(2,365)	(4,524)
Load		316,228	310,167	313,671	375,732	417,813

# **B.2** High Electrification Scenario

### Table 30. Selected Resources by Technology (High Electrification Scenario)

Selected Resources by Technology	Unit	202	0 2025	2030	2040	2050
Geothermal	MW	-	-	2,640	2,960	2,960
Wind	MW	9,895	9,895	10,871	14,585	14,585
Wind_Offshore	MW	-	-	-	-	-
Solar	MW	8,648	8 8,648	9,553	57,228	109,834
Customer Solar	MW	-	-	-	-	-
Battery Storage	MW	-	1,052	5,438	35 <i>,</i> 653	74,411
Pumped Storage	MW	-	-	-	-	-
Energy Efficiency	MW	-	-	-	-	-
DR	MW	-	-	-	-	-
Flexible Load	MW	-	-	618	3,427	3,427
Hydrogen Electrolysis	MW	79	9 102	138	264	349

Total Installed Capacity	Unit	2020	2025	2030	2040	2050
Nuclear	MW	3,379	2,229	1,079	1,079	-
СНР	MW	72	27	27	-	-
Coal	MW	1,800	1,800	-	-	-
Gas CCGT	MW	20,742	20,742	20,195	20,195	20,195
Gas Peaker	MW	10,084	8,192	4,830	4,830	4,830
Hydro	MW	12,610	12,610	12,610	12,610	12,610
Hydro (Small)	MW	595	595	595	595	595
Biomass	MW	787	787	787	787	787
Geothermal	MW	1,586	1,586	4,196	4,516	4,516
Wind	MW	16,748	16,748	17,724	21,438	21,438
Wind_Offshore	MW	-	-	-	-	-
Solar	MW	21,152	21,471	22,376	70,051	122,657
Customer Solar	MW	5,821	9,596	15,335	20,002	24,742
Battery Storage	MW	478	1,530	5,916	36,131	74,889
Pumped Storage	MW	3,049	3,049	3,049	3,049	3,049
Energy Efficiency	MW	-	-	-	-	-
DR	MW	1,752	1,752	1,752	1,752	1,752
Flexible Load	MW	-	-	618	3,427	3,427
Hydrogen Electrolysis	MW	79	102	138	264	349

## Table 31. Total Installed Capacity by Technology (High Electrification Scenario)

### Table 32. Annual Generation by Technology (High Electrification Scenario)

Annual Generation	Unit	2020	2025	2030	2040	2050
Nuclear	GWh	29,597	19,523	9,450	9,450	-
СНР	GWh	626	237	237	-	-
Coal	GWh	12,532	12,271	-	-	-
Gas CCGT	GWh	56,075	57,230	64,855	45,309	25,023
Gas Peaker	GWh	1,122	799	268	-	11
Hydro	GWh	28,720	28,704	28,783	28,430	27,765
Hydro (Small)	GWh	5,211	5,211	5,211	5,211	5,211
Biomass	GWh	6,892	6,892	6,892	6,892	6,892
Geothermal	GWh	13,894	13,894	33,430	35,673	35,673
Wind	GWh	52,390	52,287	55,404	66,810	66,936
Wind_Offshore	GWh	-	-	-	-	-
Solar	GWh	57,396	57,590	59,515	184,546	316,346
Customer Solar	GWh	11,578	19,084	30,498	39,781	49,206
Battery Storage	GWh	3	(322)	(1,398)	(11,197)	(24,490)
Pumped Storage	GWh	(191)	(551)	(690)	(1,264)	(1,490)
Energy Efficiency	GWh	-	-	-	-	-
DR	GWh	-	9	5	-	-
Imports	GWh	41,940	39,653	27,298	19,441	9,616
Exports	GWh	(1,460)	(1,529)	(1,265)	(2,217)	(4,578)
Load		316,325	310,979	318,490	426,864	512,120

# Appendix C. RECAP Model Documentation

# C.1 Background

As overviewed in Section 2.6, RECAP is a loss-of-load-probability model developed by E3 to examine the reliability of electricity systems under high penetrations of renewable energy and storage. In this study, RECAP is used to assess reliability using the *loss of load expectation* (LOLE) metric. LOLE measures the expected number of hours/yr when load exceeds generation, leading to a loss of load event.

LOLE is one of the most commonly used metrics within the industry across North America to measure the resource adequacy of the electricity system. LOLE represents the reliability over many years and does not necessarily imply that a system will experience loss of load every single year. For example, if an electricity system is expected to have two 5-hour loss of load events over a ten-year period, the system LOLE would be 1.0 hr/yr LOLE (10 hours of load over 10 years).

There is no formalized standard for LOLE sufficiency promulgated by the North American Electric Reliability Coordinating Council (NERC), and the issue is state-jurisdictional in most places expect in organized capacity markets. There is no explicit reliability-based standard in California. Instead, the California Public Utilities Commission (CPUC) administers a resource adequacy (RA) program that requires load serving entities to procure to capacity sufficient to meet a 15% planning reserve margin above the 1-in-2 peak load forecast on a monthly basis. PRMs are common proxies/substitutes for explicit LOLE-based reliability standards.

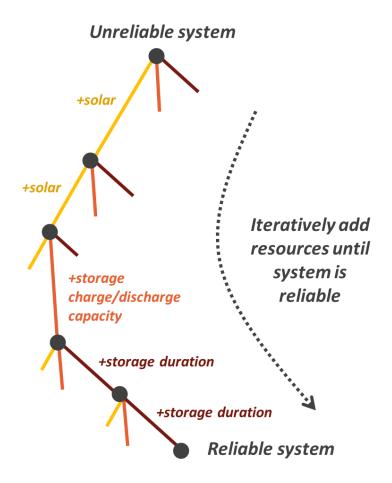
# C.2 Smart Search

RECAP uses a process called "smart search" to add resources cost-effectively to the portfolio to improve reliability. Smart search starts with a given portfolio of resources that is insufficiently reliable and evaluates the incremental improvement to reliability that results from adding small, equal-cost increments of candidate resources. The resource that improves reliability the most is added to the portfolio, and the process is then repeated with the same set of resources until the portfolio is sufficiently reliable. Smart search uses three resource options:

- + Solar (MW)
- + Storage capacity (MW)
- + Storage duration (MWh)

As Figure 31 illustrates, the model generally oscillates between selecting solar and storage to integrate the solar.

### Figure 31: RECAP "Smart Search" Process



Cost assumptions used in the RECAP smart search are consistent with the costs used in RESOLVE.

## C.3 Model Overview

RECAP calculates LOLE by simulating the electricity system with a specific set of generating resources and economic conditions under a wide variety of weather years, renewable generation years, hydro years, and stochastics forced outages of generation and transmission resources, while accounting for the correlation and relationships between these. By simulating the system thousands of times under different combinations of these conditions, RECAP is able to provide a statistically significant estimation of LOLE.

### C.3.1 LOAD

E3 modeled hourly load for California under current economic conditions using the weather years 1950-2017 using a neural network model. This process develops a relationship between recent daily load and the following independent variables:

- + Max and min daily temperature (including one and two-day lag)
- + Month (+/- 15 calendar days)
- + Day-type (weekday/weekend/holiday)
- + Day index for economic growth or other linear factor over the recent set of load data

The neural network model establishes a relationship between daily load and the independent variables by determining a set of coefficients to different nodes in hidden layers which represent intermediate steps in between the independent variables (temp, calendar, day index) and the dependent variable (load). The model trains itself through a set of iterations until the coefficients converge. Using the relationship established by the neural network, the model calculates daily load for all days in the weather record (1950-2017) under current economic conditions. The final steps convert these daily load totals into hourly loads. To do this, the model searches over the actual recent load data (10 years) to find the day that is closest in total daily load to the day that needs an hourly profile. The model is constrained to search within identical day-type (weekday/weekend/holiday) and +/- 15 calendar days when making the selection. The model then applies this hourly load profile to the daily load MWh.

This hourly load profile for the weather years 1950-2017 under today's economic conditions is then scaled to match the load forecast for future years in which RECAP is calculating reliability. This 'base' load profile only captures the loads that are present on the electricity system today and do not very well capture systematic changes to the load profile due to increased adoption of electric vehicles, building space and water heating, industrial electrification.

Light-duty electric vehicle profiles were obtained from the PATHWAYS model. Heavy duty vehicle electrification profiles were assumed to be flat across all hours of the year.

Building space and water heating profiles were sourced from PATHWAYS. To adjust the profiles across the various weather years in RESOLVE, a linear regression was used with heating degree days and a logarithmic transformation.

Operating reserves of 2000 MW are also added onto load in all hours with the assumption being that the system operator will shed load in order to maintain operating reserves of at least 2000 MW in order to prevent the potentially more catastrophic consequences that might result due to an unexpected grid event coupled with insufficient operating reserves.

### C.3.2 DISPATCHABLE GENERATION

Available dispatchable generation is calculated stochastically in RECAP using forced outage rates (FOR) and mean time to repair (MTTR) for each individual generator. These outages are either partial or full plant outages based on a distribution of possible outage states developed using CAISO data. Over many simulated days, the model will generate outages such that the average generating availability of the plant will yield a value of (1-FOR).

### C.3.3 TRANSMISSION

RECAP is a zonal model that models the California system as one zone without any internal transmission constraints. Exogenous imports of 10,000 MW are assumed to be available in all hours in addition to all California-specific resources (except for the low imports sensitivity which assumes no available imports at all).

### C.3.4 WIND AND SOLAR PROFILES

Hourly wind and solar profiles were simulated at all wind and solar sites across the Western U.S. within the RESOLVE portfolio outputs. Wind speed and solar insolation data was obtained from the NREL Western Wind Toolkit<sup>40</sup> and the NREL Solar Prospector Database<sup>41</sup>, respectively and transformed into hourly production profiles using the NREL System Advisor Model (SAM). Hourly wind speed data was available from 2007-2012 and hourly solar insolation data was available from 1998-2014.

A stochastic process was used to match the available renewable profiles with historical weather years using the observed relationship for years with overlapping data (i.e., years with available renewable data). For each day in the historical load profile (1950-2017), the model stochastically selects a wind profile and a solar profile using an inverse distance function with the following factors:

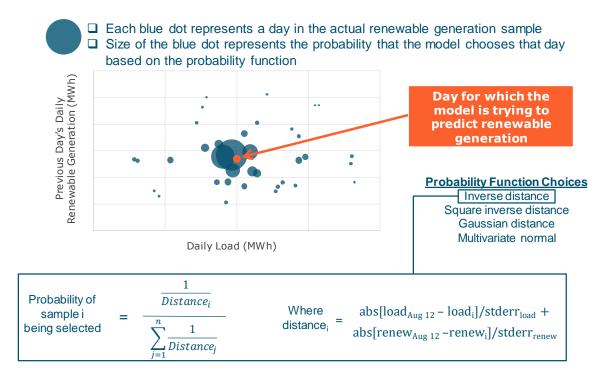
- + Season (+/- 15 days)
  - Probability is 1 inside this range and 0 outside of this range
- + Load
  - For summer peaking systems like California, high load days tend to have high solar output
- + Previous Day's Renewable Generation
  - High wind or solar days have a higher probability of being followed by a high wind or solar day, and vice versa. This factor captures the effect of a multi-day low solar or low wind event that can stress energy-limited systems that are highly dependent on renewable energy and/or energy storage.

A graphic illustrating this process is shown in Figure 32.

<sup>&</sup>lt;sup>40</sup> <u>https://www.nrel.gov/grid/wind-toolkit.html</u>

<sup>&</sup>lt;sup>41</sup> https://nsrdb.nrel.gov/

### Figure 32: Renewable Profile Selection Process



### C.3.5 HYDRO DISPATCH

Dispatchable hydro generation is a hybrid resource that is limited by weather (rainfall) but can still be dispatched for reliability within certain constraints. It is important to differentiate this resource from nondispatchable hydro such as many run-of-river systems that produce energy when there is hydro available, similar to variable wind and solar facilities.

To determine hydro availability, the model uses a historical record of hydro production data from WECC and CAISO Daily Renewable Watch which is consistent with the assumptions used in the CPUC IRP. These are chosen stochastically only based on month with no assumed correlation between temperature, load, or renewable generation. This is due to significant lag between weather conditions and hydro availability (i.e., a very snowy December may yield ample hydro availability in April). Once a hydro energy budget has been stochastically chosen for each month, it is dispatched based on net load such that higher net load hours have higher hydro generation. Dispatch is limited by any constraints such as max/min output.

### C.3.6 STORAGE

The model dispatches storage if there is insufficient generating capacity to meet load net of renewables and hydro. Storage is reserved specifically for reliability events where load exceeds available generation. It is important to note that storage is not dispatched for economics in RECAP which in many cases is how storage would be dispatched in the real world. However, it is reasonable to assume that the types of reliability events that storage is being dispatched for (low wind and solar events), are reasonably foreseeable such that the system operator would ensure that storage is charged to the extent possible in advance of these events. (Further, presumably prices would be high during these types of reliability events so that the dispatch of storage for economics also would satisfy reliability objectives.)

#### C.3.7 DEMAND RESPONSE

The model dispatches demand response if there is still insufficient generating capacity to meet load even after storage. Demand response is the resource of last resort since demand response programs often have a limitation on the number of times they can be called upon over a set period of time. For this study, demand response was modeled using a maximum of 10 calls per year, with each call lasting for a maximum of 4 hours.

### C.3.8 LOSS OF LOAD

The final step in the model calculates loss of load if there is insufficient available dispatchable generation, renewables, hydro, storage, and demand response to serve load + operating reserves.