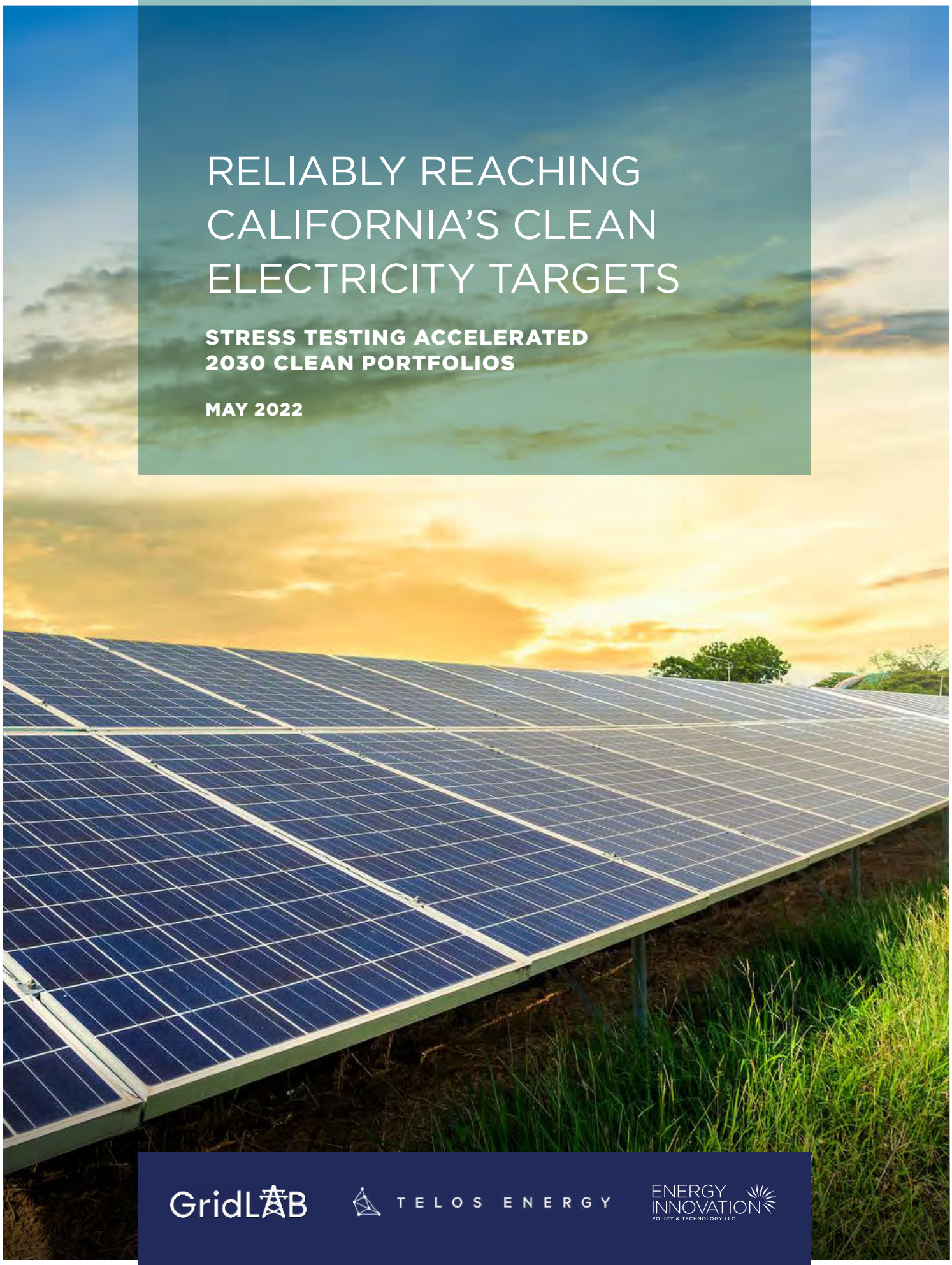
RELIABLY REACHING CALIFORNIA'S CLEAN ELECTRICITY TARGETS

STRESS TESTING ACCELERATED 2030 CLEAN PORTFOLIOS

MAY 2022



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ABSTRACT

California's Senate Bill 100 sets targets of 60% renewable energy by 2030 and 100% carbon-free electricity by 2045. In December 2020, the California Joint Agencies SB 100 report showed that accelerating this timeline to 100% carbon-free electricity by 2030 or 2035 could be cost-effective. However, policymakers identified the need for further analysis on these accelerated timeline proposals, particularly on the reliability impacts and demand flexibility value. Reliability events that occurred during August 2020 highlight the shifting resource adequacy challenges for California and the increasing importance of weather analysis in long-term planning. This study identifies an interim clean electricity target for 2030 and investigates the reliability impacts of meeting this target.

Building on the Joint Agencies SB 100 report, we evaluated the feasibility of achieving an accelerated clean (carbon-free) electricity target of 85% in 2030. We designed three portfolios that hit an 85% clean target by 2030 using RESOLVE: a base portfolio, a diverse clean portfolio with geothermal and offshore wind, and a high electrification portfolio. We evaluated these portfolios in PLEXOS and tested these portfolios against factors that could stress the grid: weather variability and its effects on renewable generation and load, removing some in-state gas units, low hydro availability, and potential coal retirements across the western interconnect. We created a specific test to emulate the August 2020 event conditions.

Our modeling shows that California is able to serve load when tested against each stressor and when the stressors are presented in combination with each other. Although it is used sparingly, the system is dependent on gas generation, either in the form of economic imports or in-state gas. We evaluated load flexibility in the form of load shifting and found that while it is helpful, its benefit is limited when large quantities of storage are built. However, we did not assess the impact of load or renewables forecast error, operational challenges for which we expect demand response resources to be valuable. While the study suggests a 85% clean electricity target can be reliable, further work should explore the impacts of transmission congestion through nodal analysis, and the impacts of inverter based resources on grid stability.

EXECUTIVE SUMMARY

CONTEXT AND OBJECTIVE

California's Senate Bill 100 sets targets of 60% renewable energy by 2030 and 100% carbon-free electricity by 2045. In December 2020, the Joint Agencies SB 100 report (hereafter, referred to as the "SB 100 report") analyzed the feasibility of the SB 100 targets and showed that accelerating this timeline to 100% carbon-free electricity by 2030 or 2035 could be cost-effective. However, the SB 100 report identified the need for further analysis to understand the reliability impacts of a clean portfolio. The reliability events that occurred during August 2020 highlight the shifting resource adequacy challenges for California and the increasing importance of weather analysis in long-term planning.

The goal of this study is to identify an interim target (e.g., 80-90% clean electricity by 2030) for California on the path to 100% clean electricity by 2035 that can be reliably met, and to provide insights to policy makers on the opportunities and key drivers for ensuring reliability against a host of stress conditions that the power system may face in the future.

The goal of this study is to identify an interim target (e.g., 80-90% clean electricity by 2030) for California on the path to 100% clean electricity by 2035 that can be reliably met, and to provide insights to policy makers on the opportunities and key drivers for ensuring reliability against a host of stress conditions that the power system may face in the future. While a few key related studies are underway, such as the California Energy Commission's Long Duration Energy Storage studies, this project aims to complement, rather than duplicate, such efforts.

METHOD

Our approach builds on the SB 100 report to evaluate the operational feasibility of achieving an accelerated clean electricity target of 85% in 2030. While the SB 100 report applies capacity expansion modeling using RESOLVE, our approach builds on this work by assessing the performance of clean electricity portfolios across all hours of the year, through production cost modeling, and by stress-testing these portfolios under multiple operating conditions.

Step 1 portfolio design: We designed three portfolios that hit an 85% clean target by 2030 using the SB 100 report version of RESOLVE: a base portfolio, a diverse clean portfolio with geothermal and offshore wind, and a high electrification portfolio. The base and diverse clean portfolios are designed for the Integrated Energy Policy Report (IEPR) mid-mid demand case. The high electrification

portfolio is consistent with the IEPR mid-mid demand case[1] but includes additional electric vehicle (EV) and building electrification; the high electrification portfolio achieves 100% EV sales by 2035 and uses moderate levels of building electrification based on the CEC AB3232 analysis. Both the diverse clean and high electrification portfolios[2] were designed with fixed input assumptions of 2 gigawatts (GW) of geothermal and 4 GW of offshore wind in 2030. All three portfolios were developed using RESOLVE with an input requirement of meeting a 75% renewable portfolio standard (RPS) target in 2030. All other input assumptions in RESOLVE are consistent with the CEC base case scenario in the SB 100 RESOLVE version.[3]

The resource mixes of each portfolio identified by RESOLVE were passed to Step 2 with the following exception: In the case of the diverse clean and high electrification portfolios, we found that the RESOLVE portfolios exceeded the desired 75% RPS level based on the outputs of Step 2 hourly production cost modeling. We adjusted the levels of utility-scale solar estimated by RESOLVE downwards to tune the portfolios, such that, under the production cost modeling outlined in Step 2, the portfolios would achieve an annual RPS level of 75%.[4]

Step 2 production cost modeling: We evaluated the Step 1 portfolios in PLEXOS, which is an hourly unit commitment and dispatch model. Our PLEXOS model represents the entire Western Interconnect and was run in a zonal mode. Each portfolio was tested in PLEXOS using eight years of coincident solar and wind data, and a single year of demand data (additional weather years for solar and summertime demand data were evaluated in sensitivities).[5] We tested each portfolio against additional factors that might impact the reliability of the power system—such as removing some in-state gas units, low hydro availability, and replacing all coal facilities across the western interconnect with renewables and storage—and evaluated these factors in combination with multiple years of weather data. We created a specific analysis to emulate the August 2020 reliability event conditions. Finally, we tested each portfolio against all of these factors combined. This resulted in 264 individual PLEXOS simulation years.

Our analysis vs. resource adequacy modeling: Typically, the analysis of resource adequacy involves analyzing a single portfolio against a range of uncertainties, usually employing some form of probabilistic analysis (either running a production cost model probabilistically, or using convolution analysis). Subsequently, metrics such as loss of load expectation (LOLE) are derived. In contrast, we took a scenario analysis approach in which multiple portfolios are assessed against key uncertainties with a specific emphasis on understanding operational performance

1 The mid-mid demand forecast is characterized by a peak gross load (prior to the impacts of BTM solar) of 64 GW, a peak net load of 56 GW (based on accounting for BTM solar generation), and an annual gross energy load of 308 TWh (264 TWh net energy load).

2 Initially, the high electrification case did not include fixed inputs assumptions of geothermal and offshore wind; however, the resulting portfolio from RESOLVE resulted in ~ 40 GW of new utility-scale solar, a level of deployment which could be challenging to achieve. Based on this interim result, a follow-on high-electrification portfolio was designed based on a similar level of geothermal and offshore wind as in the Diverse Clean Resources portfolio.

3 Named CEC_A_Base_Ref_20210204

4 Due to curtailment assumptions in RESOLVE, the levels of renewable output achieved in PLEXOS exceeded 75%.

5 These included wind data from 2007-2014 based on the NREL Wind Integration National Dataset Toolkit and solar data from 2007-2014 from the National Solar Radiation Database. The hourly demand unless stated otherwise is the California Energy Demand IEPR forecast 2020 mid-mid case. Additional weather years of demand data were available for May through October, and were evaluated through sensitivities.

across multiple years of weather data. We sought to derive intuition about the system and how these various risk factors influence the reliability of the system, independently, and in conjunction with each other.

As future decarbonized power systems become more reliant on weather and are subject to changing climatic conditions, multiple years of weather data and stress testing should be a part of any study to be credible. This type of planning and modeling should be considered a prerequisite for reliable functioning of the power system in the future. Without this type of proactive assessment, we will not know enough about how future systems will perform, and the risk of a reliability shortfall greatly increases.

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KEY METRICS

We represent the results of the production cost modeling using a variety of metrics. The three primary metrics are the RPS and clean electricity attainment, natural gas margin, and WECC hourly reserve margin. The RPS and clean electricity attainment inform whether the particular portfolio is able to meet a desired level of annual clean electricity performance when factoring in hourly operating conditions.

The natural gas margin and WECC hourly reserve margin are to be considered collectively.

- The natural gas margin represents the remaining amount of in-state gas dispatchable generation after accounting for the combination of economic imports and in-state dispatched gas. A positive natural gas margin implies that California could meet its needs without any economic imports.

  For example, if there is 25 GW of in-state gas available in a given hour (i.e., the quantity of installed gas capacity that is not on outage), in-state gas dispatch is 10 GW, and economic imports (i.e., without a contract) are 10 GW, the "gas margin" is 5 GW [25 GW available in state generation, less 10GW in-state dispatched gas, less 10GW economic imports = 5 GW].

- The WECC hourly reserve margin represents the concept that economic imports to California should not be considered a problematic condition if the rest of the region has surplus capacity. It is calculated on an hourly basis by comparing the available capacity WECC-wide, excluding California resources, to the WECC-wide demand, excluding California demand. A reserve margin greater than 100% means that the region, excluding California, has excess capacity available.

  This metric is distinct from a conventional Planning Reserve Margin (PRM), which is calculated using annual peak load and capacity, and is not an hourly

metric. In contrast, the WECC hourly reserve margin used in this report is calculated on an hourly basis and uses hourly capacity available (vs. accreditation values that are used in PRM calculations).

We track additional metrics of net generation by resource type, import/export levels, the fraction of inverter based resources (IBR), and multi-day low wind and solar events. The industry is still learning how to operate when the fraction of IBR exceeds 75%. We are specifically interested in how this fraction varies across portfolios. As renewable penetration increases, the potential for multiple days with low wind or solar output, particular in winter months (i.e., "Dunkelflaute" events) is expected to increase. We track when renewable output on a 3-day rolling basis is less than 30% of total demand and conduct a deep-dive analysis of the meteorological events driving these conditions. Due to data limitations, correlated load was not included in the baseline assumptions, but was included in a subset for some of the sensitivities evaluated.

KEY INSIGHTS

FINDING 1. California can reliably meet an 85% clean electricity standard by 2030 through multiple resource pathways, which are based primarily on wind and solar generation, and battery storage.

Our overall finding is that across the portfolios and range of sensitivities that we analyzed, our modeled 85% clean power system is able to reliably serve load as shown in Table 1. Each metric represents what is observed across the different weather years (e.g., the median represents the median across the weather years, the spread reflects the range across the different weather years). The differences in annual renewable attainment and reliability metrics (minimum natural gas margin, WECC-wide hourly reserve margin, and number of multi-day low renewable energy events) are minimal. The metric with the largest variation is the minimum gas margin, which is the difference between the available in-state gas capacity, and the sum of the in-state gas dispatch and economic imports. Across most of the sensitivities, the minimum gas margin is positive. Even in the event of a negative gas margin, a positive WECC wide reserve margin indicates the rest of the region could potentially provide exports to California.

TABLE 1.

Comparison of key select metrics for all portfolios and sensitivities across multiple weather years

		RPS (% of Sales)		Clean Electricity (% of Sales)		Minimum Gas Margin (GW)		WECC Hourly Reserve Margin during periods of Minimum Gas Margin		Minimum WECC Hourly Reserve Margin (% of Load)		California Gas Margin during periods of Minimum WECC Hourly ReserveMargin (MW)		Number of Low Wind and Solar Events (Consecutive 3-days Below 30% of Load)	
	SENSITIVITY	MEDIAN	SPREAD	MEDIAN	SPREAD	MEDIAN	LOWEST	MEDIAN	LOWEST	MEDIAN	LOWEST	MEDIAN	LOWEST	MEDIAN	LOWEST
BASE RESOURCE PORTFOLIO	**Baseline**	**76**	**2**	**87**	**2**	**7.9**	**7.5**	**53%**	**36%**	**25%**	**23%**	**23**	**21**	**10**	**4**
	WECC Coal Retirement	76	2	86	2	8.1	7.7	38%	29%	17%	16%	21	20	10	4
	Gas Retirement	76	2	87	2	(1.4)	(1.7)	48%	30%	24%	23%	8	12	10	4
	Low Hydro	76	2	84	2	7.1	6.3	62%	58%	24%	23%	21	21	10	4
	Multiple Load Years	76	2	87	2	4.5	1.9	62%	62%	23%	21%	22	15		
	Joint Sensitivity	76	2	86	2	(6.1)	(8.5)	47%	56%	16%	14%	9	3		
DIVERSE CLEAN RESOURCES PORTFOLIO	**Baseline**	**76**	**2**	**87**	**2**	**9.2**	**8.6**	**49%**	**56%**	**25%**	**23%**	**21**	**13**	**13**	**7**
	WECC Coal Retirement	76	3	86	3	9.3	8.8	31%	30%	18%	16%	20	20	0	0
	Gas Retirement	76	2	87	2	(0.5)	(0.8)	41%	36%	25%	23%	12	7	13	7
	Low Hydro	76	2	84	2	8.1	7.8	47%	42%	25%	23%	22	17	13	7
	Multiple Load Years	77	2	87	2	5.1	3.2	52%	44%	23%	22%	22	24		
	Joint Sensitivity	76	2	86	2	(5.3)	(7.5)	42%	53%	16%	14%	9	2		
HIGH ELECTRIFICATION PORTFOLIO	**Baseline**	**75**	**2**	**84**	**2**	**5.0**	**3.8**	**50%**	**37%**	**25%**	**24%**	**20**	**21**	**16**	**5**
	WECC Coal Retirement	75	2	83	2	4.8	4.0	36%	33%	18%	16%	18	22	16	5
	Gas Retirement	75	2	84	2	(3.9)	(4.8)	45%	37%	25%	24%	10	5	16	5
	Low Hydro	75	2	82	2	4.0	2.7	42%	40%	25%	24%	19	18	16	5
	Multiple Load Years	75	2	84	2	3.1	0.9	56%	59%	23%	22%	20	23		
	Joint Sensitivity	75	2	83	2	(6.7)	(9.5)	42%	48%	17%	14%	9	9		

Note: The minimum gas margin and minimum WECC hourly reserve margin is reflective of the 1st percentile value, to remove outliers; the values reported are either the median, or lowest value, of the 1st percentile values across all weather years.

FINDING 2. **Diverse clean resources (e.g., offshore wind, geothermal) help reduce the levels of solar and storage needed to achieve clean electricity goals. They will be increasingly helpful with higher levels of demand from electrification. They also reduce dependence on gas generation and lessen the impact of inverter based resources.**

Our analysis shows that an 85% clean system can operate reliably at high shares of wind, solar, and storage.

However, resource diversity through in-state offshore wind and geothermal (as one option of clean firm resources) strengthens the state's resource mix and reduces the estimates of new solar build requirements by half, which reduces land-use requirements and transmission needs of reaching clean electricity targets. Explicitly making diversity of clean resources a goal is one approach to compensate for the limitations of planning tools, which often do a poor job of accounting for the uncertainty in future technology costs or geographic diversity of renewable resources.

FINDING 3. **California will need to retain a large amount of the existing gas fleet, although gas generation will be used sparingly; California can target the retirement of environmental-justice sensitive units early on and still serve load.**

We removed gas units that operated at less than a 10% capacity factor as one of our stress testing sensitivities. We cross referenced these units against screens in CalEnviroScreen,[6] and believe that alternative retirement decisions could be made, other than ones based on plant utilization, to protect vulnerable populations with similar resource adequacy results. The remaining gas generators in the state are used strategically for reliability purposes.

FINDING 4. **The California system will remain reliable even if all the coal power plants across the west are retired and replaced with a clean energy portfolio, however, economic imports to California will remain an important source of power.**

Although our base case reflects announced retirements of coal generators, it's possible that states in the west may accelerate their coal retirements due to climate goals or worsening coal economics. Our analysis shows that replacing the fleet with an equivalent clean energy portfolio consisting of solar and storage primarily, is similarly reliable, though economic imports remain important.

6 https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40 / https://oehha.ca.gov/media/downloads/calenviroscreen/report/calenviroscreen40reportf2021.pdf

The retirement and replacement of these units does not introduce unserved energy in any of the affected regions, indicating that policies that replace coal with clean energy could be effective in reducing emissions and maintain reliable bulk electric service—provided that interregional coordination allows for appropriate transfers of electricity and local transmission constraints are resolved.

FINDING 5. The California system can meet load when assessed against extreme weather conditions as represented in multiple weather years. This assessment includes multi-day low wind events and extreme heat like those which occurred during the August 2020 rolling outages.

We recreated the circumstances from the August 2020 rolling blackouts, namely the extreme weather and limited imports, and found that our future portfolios are robust against these conditions. Our analysis tested, also, the system using the weather-dependent summer month load shapes developed by the CEC, and we find our system is robust when considering this load variability (vs. the other analyses which used the IEPR mid-mid projections). This approach is complementary to traditional resource adequacy (RA) analysis. This kind of stress-testing is not conducted in conventional resource adequacy analysis, which typically tests a single portfolio against multiple uncertainties.

FINDING 6. The system reliably serves load when tested against multiple stressors occurring simultaneously (retired in-state gas, retired west-wide coal, import constraints, low hydro availability, extreme weather).

Although this test does not necessarily represent a realistic set of conditions, we found that all portfolios perform reliably when tested against all the "stressors" simultaneously. This result is meant to provide a level of confidence that the system can perform reliably if faced with these circumstances. (Additional analysis, as noted in Finding 9, is essential to further test the system against operational and other kinds of uncertainties.)

FINDING 7. Load flexibility/load shifting can offset some battery needs and provide a hedge against uncertainty in predicting resource availability and high demand events. This hedge value will be important in the winter as newly electrified loads are expected to contribute to winter reliability risk.

Due to the high levels of storage in the portfolios we analyzed, the system is generally able to derive the levels of flexibility it needs from storage. However, various forms of demand response, including load shifting and shed, are important operational tools that can compensate for uncertainties in demand and renewable

forecasting, and are dispatched prior to shedding operating reserves. Demand-side resources can substitute for battery storage if deployment of storage does not match the ambitious time table on the base case. While we don't study this aspect, load flexibility, such as managed EV charging, can play a role in mitigating capacity investments on the distribution system.

FINDING 8. Modeling tools and planning processes need to evolve to better capture the effects of geographically diverse resources, uncertainties about technology costs, and the impact of inter-regional coordination.

Modeling tools, datasets, and planning processes will need to be adapted to better represent a decarbonized western power grid. These changes include capturing geographic resource diversity, adding weather years, incorporating synchronized renewable and load data sets across the entire region, considering inter-regional coordination, integrating emerging technologies (flexible load, hybrid resources), and supplementing capacity expansion modeling with heuristic approaches and/or other tools/methods that account for model and data uncertainty.

FINDING 9. This analysis does not cover all potential reliability issues associated with hitting an 85% clean electricity target. Assessing clean portfolios with additional sets of weather data, transmission and generator outage conditions, and assessing grid stability are needed as next steps in modeling a reliable power system.

It is important to acknowledge that while we did model pathways to a reliable system and used some robust, policy-relevant stress tests, this study is not a complete reliability analysis. We did not examine resource adequacy metrics or power flows, or conduct nodal analysis to identify transmission congestion. While we assessed WECC-wide decarbonization to some extent through a coal retirement sensitivity, we did not analyze an 85% clean target WECC-wide. Nor did we analyze resilience against wildfire risk. But this analysis provides a robust foundation for more work. We have the tools needed to perform these deeper modeling exercises to further increase the faith in a reliable power system, and encourage California policymakers to undertake it.

INTRODUCTION

BACKGROUND: JOINT AGENCIES SB 100 REPORT

California's Senate Bill 100 sets targets of 60% renewable energy by 2030 and 100% carbon-free electricity by 2045. In December 2020, the Joint Agencies SB 100 report (referred to as the "SB 100 report") analyzed the feasibility of the SB 100 targets and showed that accelerating this timeline to 100% carbon-free electricity by 2030 or 2035 could be cost-effective. However, the SB 100 report identified the need for further analysis, specifically to understand the reliability impacts of a clean portfolio, and the role of demand side flexibility in meeting these goals.

The reliability events that occurred during August 2020 highlight the shifting resource adequacy challenges for California, the potential role of extreme weather and import dependencies, the challenge of correlated thermal outages, and the role that demand response can play in mitigating these events. The August event underscored the importance of weather analysis in long-term planning. Future power systems are going to be fueled primarily by weather, not by fossil fuels; as such, understanding reliability as it relates to inter-year weather variability and extreme weather is critical.

PURPOSE: IDENTIFY AN INTERIM TARGET ON THE PATH TO 100% CLEAN ELECTRICITY

This study aims to identify an interim target—between 80-90% clean electricity by 2030—that would put California on a path to 100% clean electricity by 2035. The study evaluates whether the interim targets can be reliably met, and to provide insights to policy makers on the opportunities and key drivers for ensuring reliability against a host of uncertainties that the power system may face in the future. While a few key related studies are underway, such as the California Energy Commission's Long Energy Duration Storage projects,[7] this study complements and builds on these efforts. The focus of the study is limited to the dimension of reliability. It does not include further understanding the economic or rate impacts of SB 100 beyond the SB 100 report.

7 Two studies have been commissioned by the CEC to understand the value of long duration storage to California's power system: One study is being led by the University of California, Merced (UC Merced), and another study by Energy and Environmental Economics, Inc. (E3). Project update workshops for the UC Merced project are here https://www.energy.ca.gov/event/workshop/2021-11/staff-workshop-strategies-model-long-duration-storage and for the E3 project are here: https://www.energy.ca.gov/event/workshop/2021-06/staff-workshop-proposed-development-long-duration-energy-storage-scenarios

SCOPE: STRESS TESTING MULTIPLE PORTFOLIOS USING PRODUCTION COST MODELING

The ESIG Task Force on Redefining Resource Adequacy for Modern Power Systems[8] lists a number of key principles for analyzing the resource adequacy of future power systems. Among the six principles, two of them state the importance of analyzing chronology across many weather years and understanding the role of demand side resources. The SB 100 report results are based on capacity expansion modeling (using RESOLVE), which does not assess the reliability of a portfolio against a full year chronological set of generation and load data. This study developed portfolios using RESOLVE and evaluated these in a production cost model, which enabled the analysis to better assess the hour to hour reliability of the system. Each portfolio was tested against a set of conditions that may stress the future power system, including variable weather, reduced gas and coal generation, and low hydro availability and imports.

While we complete over 260 simulations in a production cost model, we note that our analysis differs from traditional resource adequacy analysis that includes probabilistic methods in which hundreds of random samples of generator forced outages are drawn, and includes dozens of years of load and resource data. While we did not conduct this type of analysis, the aim of our study was to increase our understanding of the phenomena that may drive reliability in the future, given various uncertainties. This analysis represents a complementary step to both capacity expansion modeling (through RESOLVE) and probabilistic traditional resource adequacy analysis.

Our scope of reliability assessment is restricted to hourly production cost modeling and conducted at the zonal level (8 zones in California and 18 outside of California), rather than at the nodal level, which would be important for understanding local transmission constraints. We did not conduct dynamic stability analysis, another important dimension of reliability. In other words, while we test the power system for resource adequacy to meet a clean electricity standard, the implementation of a clean electricity standard would require analysis that looks at these other dimensions of reliability.

8 Energy Systems Integration Group, Redefining Resource Adequacy for Modern Power Systems, 2021, https://www.esig.energy/reports-briefs.

MODELING FRAMEWORK AND DATA

To understand the impact of an accelerated California clean electricity target, we used a six step analytical process (Figure 1). In the first step, we collected and combined relevant datasets, primarily from the California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) and other studies. In step two, we identified a set of portfolios and accelerated clean electricity targets in 2030. In step three, we developed the resource portfolios for each scenario using the Renewable Energy Solutions Model (RESOLVE), which is a capacity expansion planning model that was used to support the SB 100 report and is used in the CPUC Integrated Resource Planning process. In Step four, we developed hourly renewable data sets for those portfolios for multiple weather years. In Step five, the portfolios were tested using the hourly production cost model, PLEXOS. In the final step, we translated the PLEXOS outputs into various metrics.

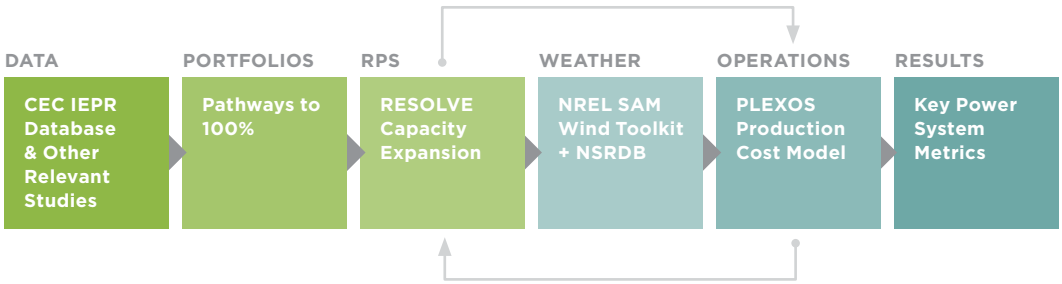

FIGURE 1.

Modeling Framework and Methodology

We describe the modeling framework in more detail.

LINKING MODELING TOOLS FOR ROBUST ANALYSIS

This study used a suite of power system modeling tools, including the National Renewable Energy Laboratory (NREL) System Advisor Model,[9] RESOLVE,[10] and PLEXOS,[11] to develop cost-effective clean electricity portfolios and to simulate grid operations across a wide range of potential weather, load, and system conditions.

9 National Renewable Energy Laboratory, System Advisor Model, https://sam.nrel.gov/

10 Energy and Environmental Economics, Inc., RESOLVE: Renewable Energy Solutions Model, https://www.ethree.com/tools/resolve-renewable-energy-solutions-model/

11 Energy Exemplar, PLEXOS, https://www.energyexemplar.com/plexos

These tools are used across the industry by utilities, grid operators, regulators, and researchers for grid planning.

The study used RESOLVE to estimate future generation buildout requirements and PLEXOS to evaluate hourly operations of the power system. These models were used in an iterative fashion. RESOLVE is a least-cost capacity expansion model, developed by Energy and Environmental Economics (E3), originally, to support integrated resource planning in California. RESOLVE develops least-cost portfolios of resources subject to a set of constraints, such as an RPS target or carbon dioxide emission reduction target. We exercised RESOLVE to develop portfolios that achieve a 75% RPS in 2030. In our study, RESOLVE was used exclusively as a technology screening tool to identify potential portfolios of resources that could meet the RPS requirement based on static cost assumptions. The source of the RESOLVE model was the publicly available version of RESOLVE developed to support the SB 100 report.[12] We did not change the assumptions or methodologies in RESOLVE (e.g., candidate resource types, cost assumptions, day weights, load shapes[13]).

The RESOLVE portfolio results—specifically the installed capacity by technology type and location—were inputted to PLEXOS to perform hourly chronological modeling across multiple years of weather data. PLEXOS is a licensed proprietary model used by grid operators globally to perform hourly or sub-hourly simulations of grid operations. In contrast to RESOLVE, PLEXOS simulates all hours across an entire year of operation, characterizes generating units with a high degree of operational specificity (e.g., heat rate curves, ramp rates, min up and down times, outage rates), and uses a more detailed zonal transmission topology relative to the zonal topology in RESOLVE. Our PLEXOS model includes a more detailed representation of the Western Interconnection, incorporating changes to economic and dedicated imports (imported energy with a PPA contract) from neighboring systems.

Our modeling process was iterative in the following ways:

- We analyzed three distinct portfolios. The development of each new portfolio, which represents a different future resource build, required a new instance of running RESOLVE.
- For some portfolios, we found the annual renewable generation achieved, based on PLEXOS hourly outputs, to exceed the 75% RPS target that was assumed in RESOLVE[14]; in these instances, we adjusted the portfolio manually and remodeled the portfolio in PLEXOS until we found the PLEXOS output and RESOLVE 75% RPS assumption to roughly match.

12 Available at https://www.energy.ca.gov/sb100#anchor_report

13 For the high electrification scenario, which is described subsequently, we increased the amount of annual electrified building and transportation load from the preloaded annual electrified load assumptions in RESOLVE.

14 We found higher levels of curtailment in RESOLVE than in PLEXOS. Differences between RESOLVE and PLEXOS can be attributed to differences in the underlying weather conditions and associated resource profiles and hourly load profiles; and that RESOLVE uses 37 sample days rather than an entire year.

While the development of new portfolios (representing different scenarios to reach an accelerated RPS target) used RESOLVE primarily, our evaluation of the portfolios against different conditions (such as varying weather conditions, low hydro availability, etc.)—what we term 'sensitivities'—exclusively used PLEXOS. In general, we did not adjust the resource portfolios for the sensitivity analysis, and where that is done, we perform the adjustments manually. We describe our development of portfolios and sensitivities in detail in the next section.

DIFFERENTIATING RESOURCE ADEQUACY PLANNING AND STRESS TESTING

Evaluating the reliability of a future power system includes many facets and spans distribution reliability, transmission network stability, resource adequacy, and resiliency. Resource adequacy evaluates the likelihood of a system having insufficient generation resources to serve load, and its dependence on neighboring regions for emergency imports. It is an important component of long-term planning and its importance is increasing as our power system is evolving with greater levels of variable renewable energy. However, the traditional approaches of analyzing resource adequacy in system planning are insufficient for assessing risks of emerging power systems. Traditional system planning typically incorporates resource adequacy analysis as an input into the capacity expansion model; the resource adequacy analysis determines the necessary planning reserve margin required to maintain a specified level of reliability, which serves as an *input* to the capacity expansion model. A follow-up resource adequacy assessment of the portfolio produced by the capacity expansion model is not usually performed. Rather, it is assumed that by meeting the *planning reserve margin*, the system is resource adequate.

An implicit assumption in the traditional planning process is that reliability is not impacted if the composition of the portfolio used in the resource adequacy model is different from the portfolio that results from the capacity expansion model. However, the accuracy and usefulness of a planning reserve margin degrades as the power system has increasing levels of renewable energy and energy limited resources.[15] Given the interactions and correlations among generation, storage, load, and weather, it is important to conduct a resource adequacy analysis after the portfolio has been developed. **In fact, given these dependencies and limitations of current capacity expansion models, there is value in employing an iterative modeling approach between the capacity expansion modeling (i.e., portfolio design) and resource adequacy analysis.**

Resource adequacy analysis can employ different approaches. Traditionally, resource adequacy analysis evaluated system adequacy *for a given resource mix* using probabilistic methods such as Monte Carlo sampling.[16] Many years of weather and load data are compiled and simulated, and a large number of random generator outage samples are drawn. This approach allowed system planners to

15 Redefining Resource Adequacy Task Force. 2021. Redefining Resource Adequacy for Modern Power Systems. Reston, VA: Energy Systems Integration Group. https://www.esig.energy/resource-adequacy-for-modern-power-systems/

16 Convolution is an alternative method that has been used traditionally and is more computationally efficient than Monte Carlo sampling.

quantify the likelihood of system shortfalls and to characterize these shortfalls using metrics such as loss of load expectation (LOLE) or expected unserved energy (EUE). While probabilistic analysis remains a critical component of system planning, it has its limitations as it is computationally intensive and is assessing the reliability of a single resource mix. In conducting analysis across hundreds or thousands of samples, technical simplifications are often required and the volume of data can overshadow insights into specific drivers of resource adequacy risk. In addition, probabilistic analysis typically assumes independence in generator outages, failing to consider root cause and correlated events.

A core tenet of this study is that stress testing specific conditions—for more than one set of hypothetical resource mixes—is necessary to develop the insights needed to inform policy decisions and ensure appropriate resources are added to the system to meet reliability targets in cost-effective ways.

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This bifurcated process for resource adequacy planning (Figure 2) highlights the need for both probabilistic analysis and stress testing of specific system conditions for multiple portfolios. Probabilistic resource adequacy analysis is regularly conducted by the California Independent System Operator (CAISO) in their seasonal Loads and Resource Assessments,[17] and the California Public Utilities Commission (CPUC) Integrated Resource Planning in their SERVM analysis.[18] The methodology we implemented in this study uses the stress testing approach.

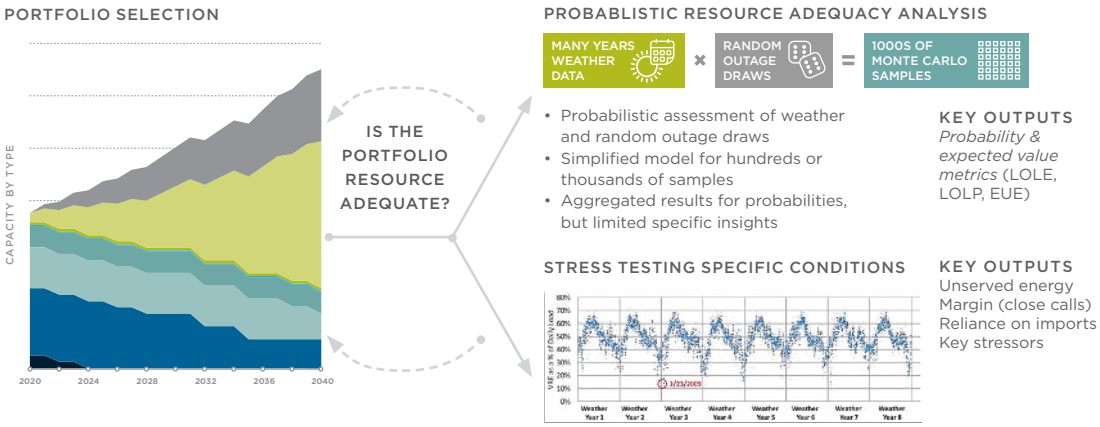


FIGURE 2.

Probabilistic Analysis vs. Stress Testing Approaches for Resource Adequacy Analysis

17 California ISO, 2021 Summer Readiness Report, http://www.caiso.com/about/Pages/News/SummerReadiness.aspx

18 California Public Utilities Commission, Presentation Summarizing SERVM Analysis, December 2021, ftp://ftp.cpuc.ca.gov/energy/modeling/IRP_PSPo_2020IEPR_HEV_SERVM_final.pdf

LEVERAGING CEC IEPR DATA AND CEC PLEXOS MODEL

In the first step of our analysis, we leveraged data provided by the California Energy Commission, primarily California Energy Commission's production cost model dataset from May 2021 that was developed for the 2021 Integrated Energy Policy Report, and later edited for the report. The dataset reflects the 2020 California Energy Demand (CED), and was updated to incorporate recent generation installations, announced retirements, and network changes.[19] The database assumed a generation-weighted $4.81/MMBtu gas price (nominal 2030$) for California, relative to a $3.56/MMBtu price across the rest of the West. The PLEXOS model represents generation and load across the entire Western Interconnection on a zonal basis, including all grid-connected, utility-scale generators. The capacity by type across the Western interconnection (Figure 3) does not reflect the additions required for meeting an accelerated clean electricity target. The installed capacity for external WECC regions was held constant throughout the analysis unless otherwise noted in specific sensitivities.

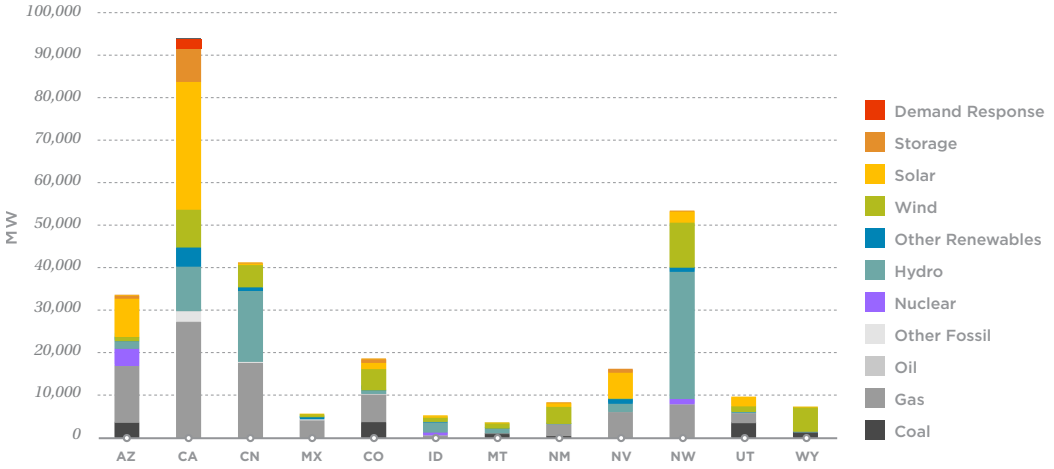


FIGURE 3.

CEC PLEXOS Database showing Installed Capacity by WECC Region in 2030, prior to capacity additions for accelerated California clean electricity targets[20]

The load forecast used throughout the analysis, unless otherwise noted, is the California Energy Demand Forecast Update (CEDU) 2020 Mid-Mid case forecast for 2030. This forecast includes impacts of behind the meter solar and storage, energy efficiency, electric vehicle adoption, and building electrification. This forecast is characterized by a peak gross load (prior to the impacts of BTM solar) of 64 GW, a peak net load of 56 GW (based on accounting for BTM solar generation), annual gross energy load of 308 TWh (264 TWh net energy load), and RPS eligible sales of 239 TWh.

19 For additional information on this dataset please send an email to ES.Modeling@energy.ca.gov.
20 CN = Alberta and British Columbia Canada, MX = Baja Mexico

We modified the CEC PLEXOS model in a limited manner for this study. The largest change was an update to all of the 8760 hourly wind and solar profiles across the WECC, the details of which are provided in the following section.

A second change we made was to model behind the meter solar PV (BTM solar) as a supply side resource, rather than embedding it within the load profile. Modeling BTM solar as a supply-side resource is a valuable improvement to the model that increases our ability to understand the impacts of BTM solar on the power system; on aggregate, BTM solar represents one of the largest sources of energy in the state. The advantages to modeling BTM solar as a supply-side resource include the following.

Modeling BTM solar as a supply-side resource is a valuable improvement to the model that increases our ability to understand the impacts of BTM solar on the power system; on aggregate, BTM solar represents one of the largest sources of energy in the state.

- The underlying solar data for BTM solar resources are benchmarked to a consistent set of weather data that drives the utility-scale solar and wind resources, meaning that this analysis approach more accurately captures the impacts of weather on renewable generation.
- The BTM solar resource can be tracked easily in model outputs, facilitating comparison of BTM solar generation with other resources on the grid.
- Operational constraints or reserves can be modeled as a function of BTM solar generation.
- Unique generation profiles can be developed for locations across the state.
- If nodal transmission analysis is conducted (not applicable to this study), BTM solar can be sited at specific load busses rather than allocated proportionally to the load.

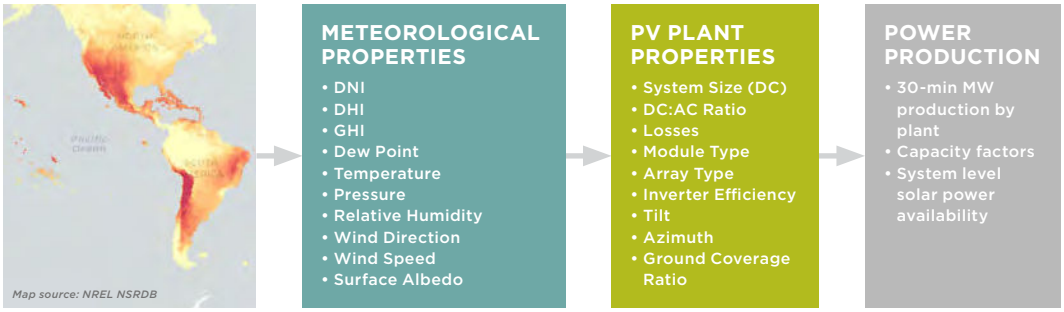
EVALUATING WEATHER DATA ACROSS MANY YEARS

We evaluated many years of weather data in the PLEXOS model to properly assess the reliability and operations of an accelerated clean electricity standard. According to the Energy Systems Integration Group (ESIG), **"Many years of synchronized hourly weather and load data are necessary to understand correlations and interannual variability between wind and solar generation, outages, and load. The same weather conditions can affect wind and solar output, whose probabilities are driven by irregular and complex weather patterns, and load and thermal unit derates—requiring that the weather data be consistent across these inputs."**[21]

To ensure the correlation of wind and solar generation, geographically and temporally, the PLEXOS model incorporated multiple years of location-specific, time synchronized wind and solar generation profiles across the Western Interconnection. This multi-year dataset is critical to understanding the multi-year

21 Energy Systems Integration Group, Redefining Resource Adequacy for Modern Power Systems, 2021, https://www.esig.energy/reports-briefs.

variability of the wind and solar resources, the likelihood of multi-day sustained low renewable energy production, and the characteristics of outlier events. The multi-year solar dataset ranges from 1998 to 2019 and is based on modeled weather "data" from the NREL National Solar Radiation Database (NSRDB); the multi-year wind dataset ranges from 2007 to 2014 and is based on modeled weather "data" from the NREL Wind Integration National Dataset Toolkit (WIND ToolKit). The weather data from NSRDB and the WIND Toolkit were passed through the NREL System Advisor Model (SAM) to create chronological 8,760 hourly production data for both solar and wind resources. The steps to move from solar weather information to solar plant hourly production is illustrated in Figure 4. (Though not shown, a similar stepwise process was used for wind resources.) Figure 5 shows the locations of utility-scale wind and solar projects across the western interconnection.



A SIMILAR DATABASE WAS DEVELOPED FOR WIND ACROSS CALIFORNIA

FIGURE 4.

Overview of weather modeling used to develop multi-year solar dataset

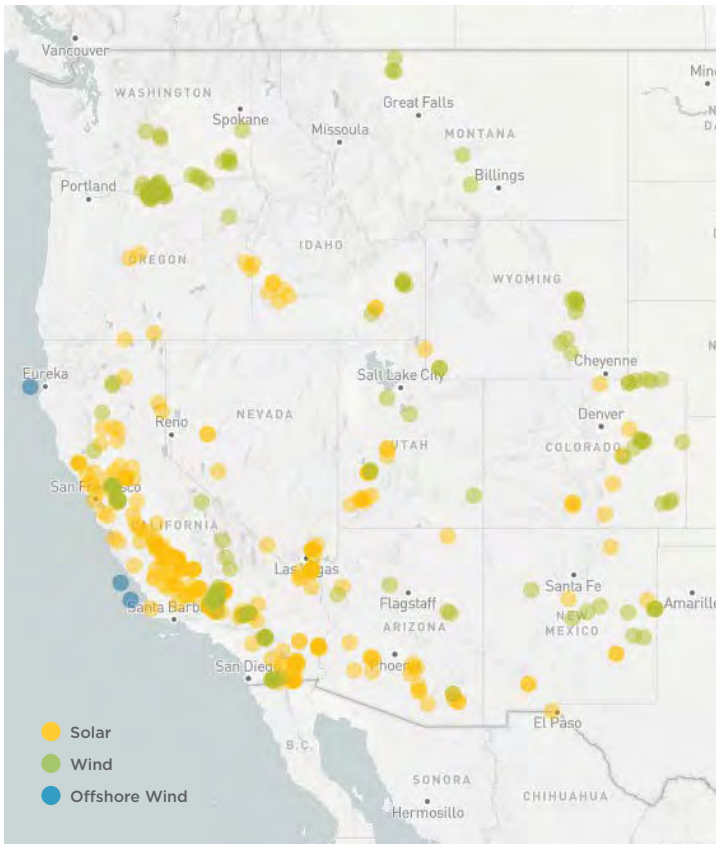


FIGURE 5.

Locations of utility-scale wind and solar across the Western Interconnect.

Solar generation hourly profiles

We developed hourly generation profiles for utility-scale solar PV plants, applying site information from the EIA Form 860, as follows:

- Existing utility scale projects above 20 MW: A unique solar profile was developed based on its specific latitude and longitude in the EIA Form 860 database.[22] This represents over 85% of the total installed solar capacity and over 250 unique locations.
- Existing utility-scale solar projects below 20 MW: These plants were assigned a profile equivalent to the zonal weighted average, by capacity, of all the projects above 20 MW.
- Future utility-scale solar projects: These plants were assumed to be located in similar locations as existing solar but are assumed to have a higher inverter-loading ratio.

We assumed that all utility-scale solar PV projects had a single-axis tracking system, existing projects had an inverter loading ratio of 1.2, and future projects had an inverter loading ratio of 1.4.

22 U.S. Energy Information Administration, Form EIA-860 detailed data with previous form data (EIA-860A/860B), https://www.eia.gov/electricity/data/eia860/

This process was repeated for BTM solar, however a single location in each of California's 58 counties—the largest populated city—was selected to represent the profile for that county. The hourly profiles across all counties were then weighted based on the installed capacity reported in the California Distributed Generation Statistics[23] and aggregated by transmission zone. BTM solar resources were assumed to be roof-mounted and with an inverter loading ratio of 1.1.

Wind generation hourly profiles

We developed hourly wind production profiles using a similar process used to develop the solar profiles. Locational information for existing land-based wind plants greater than 75 MW were taken from EIA Form 860. This included over 140 profiles and represented 80% of all wind capacity installed in the West. Plants below 75 MW used a weighted average profile, on a capacity basis, across the region. Technology input parameters in SAM consisted of a hub height of 80m for existing plants and 100m for future plants; each modeled facility used a generic farm layout of 32 turbines that was scaled to the actual facility size.

We developed hourly generation profiles for offshore wind resources for three BOEM lease areas: Humboldt, Morro Bay, and Diablo Canyon Call Areas.[24]

Years used in the modeling

Unless otherwise noted, the production cost modeling used the consistent eight-year range of data from 2007 to 2014 for which solar and wind data were available. However, given the substantial size of solar in the future California resource mix, we conducted additional sensitivities to evaluate solar across the full 22-year solar dataset; in these sensitivities, we typically selected a pessimistic wind profile. These details are reiterated when we describe the sensitivities.

23 California Distributed Generation Statistics, https://www.californiadgstats.ca.gov/
24 BOEM Lease Areas, https://www.boem.gov/renewable-energy/state-activities/california

PORTFOLIOS AND SENSITIVITIES

PORTFOLIO DEVELOPMENT

We developed three portfolios that represent different resource pathways to achieve an accelerated clean target in 2030. The objective of this framework is to understand the tradeoffs among different resource mixes, from an operational and reliability perspective. All portfolios are comparable in terms of achieving a common clean and renewable target of 85% and 75% of retail electricity sales, respectively. However, the portfolios differ by the underlying resource mix, and in one case, the amount of load due to electrification.

We developed portfolios using RESOLVE in which we specify a **renewable portfolio standard (RPS) target of 75% by 2030.** The 75% RPS by 2030 target represents an acceleration compared to the 60% RPS target currently in statute. Our calculation of the annual renewable generation is consistent with the state's RPS definition in the statute—only utility sales covered under the RPS statute are included.[25] The quantity of renewable generation consists of RPS eligible generation (typically utility-scale solar and wind resources), small hydro, geothermal, biomass, and eligible waste-to-energy plants. Although we modeled BTM solar as a supply-side resource in PLEXOS, in our calculation of achieved RPS, BTM solar was reflected in the denominator as a reduction in utility sales. The level of BTM solar in each portfolio is common and is consistent with IEPR.[26] The three portfolios include the following:

Base Case portfolio: All input assumptions in RESOLVE are consistent with the CEC SB100 modeling "base" scenarios, except that an RPS target of 75% in 2030 was selected.[27] The load is consistent with the IEPR Mid-Mid Demand case. The resulting portfolio was used in PLEXOS without any manual adjustments, and consisted of a mix of utility-scale solar PV, wind, and energy storage (predominantly battery energy storage).

Diverse Clean Resources portfolio: This portfolio represents a future in which the California power system is characterized by more diverse clean energy resources. The assumptions in RESOLVE were similar to the Base Case portfolio, however, we forced a minimum buildout of 2 GW of geothermal energy and 4 GW of offshore wind. Geothermal was used as a proxy for firm renewable energy, but is representative of any resource that is fully

25 Note that the RPS eligible sales do not include certain loads such as some excluded water pumping, round-trip efficiency losses for energy storage, transmission or distribution losses, or other components of the system's net energy for load. Thus the total renewable energy as a percentage of total load (as opposed to RPS sales) will be lower.

26 BTM Solar is an input in RESOLVE and this value was unchanged from the values pre-existing in the SB100 RESOLVE version.

27 The scenario named "CEC_A_Base_Ref_20210204" in RESOLVE was modified to have a 75% RPS target in 2030.

dispatchable. The resulting portfolio from RESOLVE was adjusted manually, by scaling the solar and storage downwards, after an iteration in PLEXOS to better match an 75% RPS target.[28]

High Electrification portfolio: This portfolio reflects a future in which California achieves higher levels of electrification as compared to the Base Case. The load was increased with building electrification levels taken from the CEC AB3232 moderate case, and for transportation, assumed to be consistent with 100% electric vehicle sales by 2035 taken from the UC Berkeley 2035 Transportation report.[29] This resulted in approximately 15% increased load, evenly split between transportation electrification and building electrification. We ran RESOLVE in an iterative manner; based on the amounts of in-state solar that would be required, we included 2 GW firm renewable and 4 GW of offshore wind from the Diverse Clean Resources portfolio. RESOLVE was rerun following this addition. Similar to the Diverse Clean Resources portfolio, after an iteration in PLEXOS, we manually adjusted the levels of solar and storage to match a 75% RPS target.

Each portfolio represents different possible clean future power systems and can help policy makers answer different types of questions, such as those shown in Figure 6.

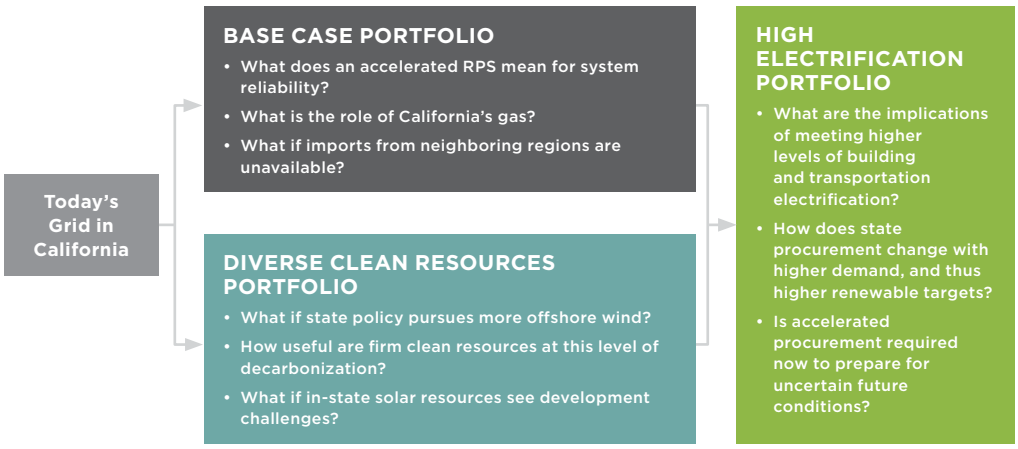


FIGURE 6.

Key questions that each portfolio may help answer

28 A primary reason for the discrepancy is that the level offshore wind curtailments assumed in RESOLVE (which uses 37 sample days instead of 8760 hour chronological modeling) were higher than in PLEXOS.

29 The 100% electric vehicle sales by 2035 load information was taken from the University of California 2035 Transportation report, Plummeting Costs And Dramatic Improvements In Batteries Can Accelerate Our Clean Transportation Future, April 2021, 2035report.com Note, this data combined the 100% LDV sales by 2035 from the alternative scenario and the 100% MDV and HDV sales by 2035 from the main ("DRIVE") scenario.

While the RPS target is a useful metric to track for the existing laws in California, it does not include all zero-carbon or renewable resources on the system, namely existing large pondage hydro, nuclear, and a handful of other small ineligible waste-to-energy resources. Because the objective of this study is to identify pathways towards decarbonization, we analyzed how the portfolios measured against a **clean electricity target of 85% clean by 2030**.

PORTFOLIO COMPOSITIONS

Based on RESOLVE, a pathway that consists primarily of solar and storage resources (25 GW and 17 GW, respectively) combined with some additions of on-shore wind (11.5 GW) is the lowest cost portfolio. The Diverse clean resources portfolio represents an alternative pathway to achieving the 85% clean electricity target while integrating offshore wind (4 GW) and geothermal as a proxy for firm renewable resources (2 GW). Adding these resources results in a reduction of new solar capacity needed (-13 GW) and new storage capacity (-7 GW).

Because the objective of this study is to identify pathways towards decarbonization, we analyzed how the portfolios measured against a clean electricity target of 85% clean by 2030.

The third portfolio, the High Electrification portfolio, reflects higher levels of building and vehicle electrification levels; like the Diverse Clean Resources portfolio, the High Electrification portfolio also integrates 4 GW of offshore wind and 2 GW of geothermal, while adding 2 GW of utility-scale solar relative to the base case. The incremental new build capacity, relative to the current installed and announced renewable capacity in California is shown in Table 2 and Figure 7.

TABLE 2.

Renewable and Storage Compositions of each Portfolio

	CAPACITY ADDITIONS (GW) (1)			TOTAL CUMULATIVE CAPACITY (GW) (2)		
	BASE CASE	DIVERSE CLEAN RESOURCES	HIGH ELECTRIFICATION	BASE CASE	DIVERSE CLEAN RESOURCES	HIGH ELECTRIFICATION
Utility scale solar	25	12	27	41	28	43
Land-Based Wind	12	11	12	18	17	18
Offshore Wind	-	4	4	-	4	4
Firm Renewable	-	2	2	4	6	6
Battery Storage	15	11	15	19	14	19
Pumped Storage	2	-	4	6	4	7

1. Capacity additions refer to new build resources identified by RESOLVE; these are incremental to the planned (or announced) resources.

2. Refers to operational capacity (existing resources, planned and new build). Does not include existing RPS wind and solar units located outside of California, which is accounted for as an RPS Import in the model.

3. Total cumulative capacity may be different than the changes in the capacity additions column due to rounding.

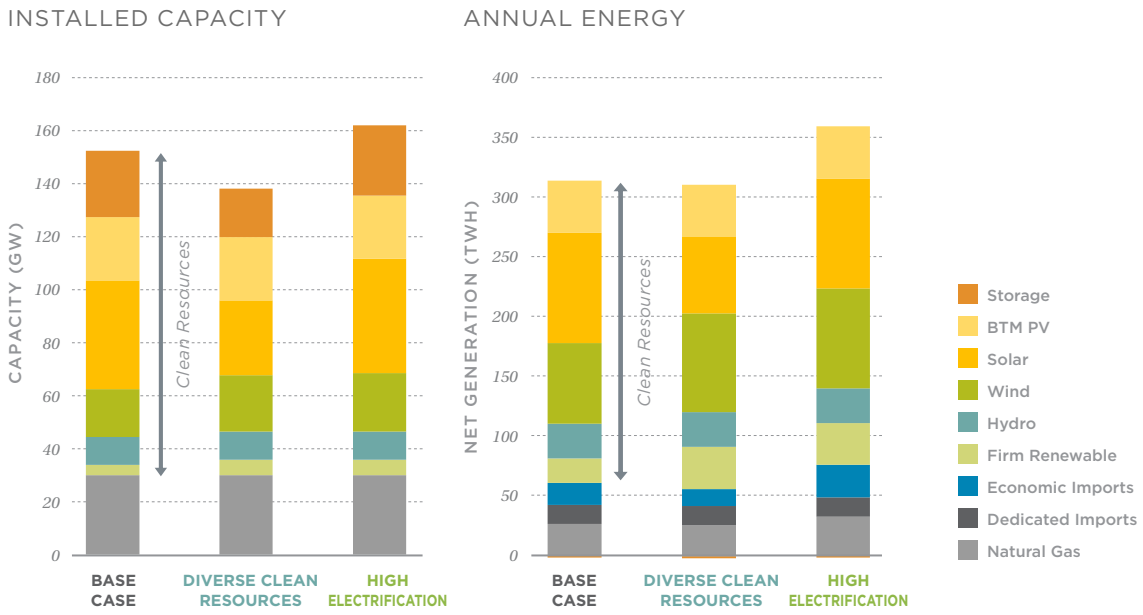


FIGURE 7.

Installed Capacity, GW (left) and Annual Energy, TWh (right) by Resource Type and Portfolio

Figure 8 shows the cumulative installed capacity for renewable resources in California since 2001[30] for utility scale solar (left frame), wind (middle frame), and firm renewable (right frame) resources. This figure illustrates the capacity required to reach the 2030 85% clean electricity target for each portfolio relative to the pace of recent capacity additions. The Base Case portfolio requires some acceleration to the trailing 10 years of installed solar PV additions, and an approximate doubling and acceleration of currently installed wind capacity. The amount of solar additions to achieve the Diverse Clean Resources portfolio are much less, and in-line with the pace of recent additions. However this portfolio, as well as the High Electrification portfolio, requires an acceleration of wind (offshore and land-based) and firm renewable resources. In all portfolios, additional utility-scale solar will be needed if BTM solar installations do not reach the projected levels in the CEC demand forecast.

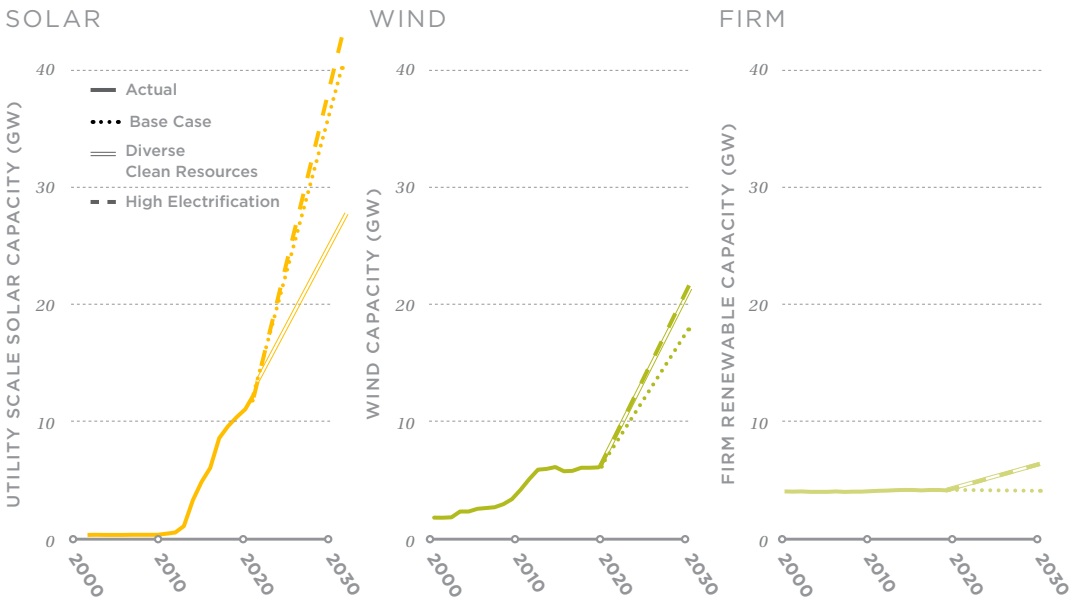


FIGURE 8.

California's Historical and Future Capacity Additions by Resource Type, by portfolio

30 California Energy Commission, Electric Generation Capacity and Energy, Installed In-State Electric Generation Capacity by Fuel Type (MW), based on CEC-1304 QFER Database as of May 11, 2021, https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy

While recent deployment of utility-scale solar resources have been significant, deployment of wind and firm renewable resources have largely stagnated in California. Achievement of the 85% clean electricity target by 2030 may require a targeted policy for offshore wind, transmission expansion to access out of state wind resources, and policies for firm renewable energy (including biomass or geothermal) to incent development of diverse resources that may not occur based solely on individual project economics. The Integrated Resource Plan adopted February 10 2022 by the California Public Utilities Commission has provisions to encourage development of some of these resources.[31]

SENSITIVITIES TO EVALUATE SYSTEM STRESSORS-DESCRIPTIONS AND METHODS

We developed six sensitivities to test each portfolio against phenomena that could stress the power system, beyond baseline conditions, and one sensitivity to explore how flexible demand could help the power system in stressful conditions. Each sensitivity was analyzed independently, for each portfolio, to isolate the impact of that particular phenomena on the power system with one exception: for the "Combined stressor" sensitivity, we analyzed the impacts of multiple stressors in combination to illustrate a worst-case situation where reliability might be severely stressed (the Combined stressor sensitivity does not include demand flexibility as a resource). Each of the portfolios and sensitivities resulted in 24 unique characterizations of the power system, each tested against 8 or more weather years, resulting in more than 200 years of simulations (Figure 9).

3 PORTFOLIOS	×	8 SENSITIVITIES	×	8 WEATHER YEARS	=	192+ YEARS OF SIMULATION*
• **Base Case** • **Diverse Clean Resources** • **High Electrification**		• Baseline Assumptions • California Gas Retirements • Low Hydro Availability • WECC Coal Retirements • California Import Assumptions • Multi-year Load Variability • Combined Stressors • Demand Flexibility		• 2007 - 2014		

FIGURE 9.

Portfolio and Sensitivity Matrix

**The 20-year Multi-load Variability and Combined Stressor sensitivities were evaluated across 20-years, resulting in over 264 total years of simulation.*

31 CPUC announcement: https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-approves-long-term-plans-to-meet-electricity-reliability-and-climate-goals and CPUC Decision adopting 2021 preferred system plan. Rulemaking 20-05-003. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M449/K173/449173804.PDF

By considering a number of portfolios tested against a wide range of sensitivities, we stress-tested and evaluated future renewable energy portfolios to better understand the consequences of, and the potential options for, decarbonizing California's power system. This approach recognizes there is no single pathway for California's future and that it is impossible to characterize all uncertainties, but it is important to capture the major drivers. This analysis, which goes beyond single-point estimates of a future grid, and considers a wide range of potential outcomes, can support policy makers to identify least-regrets policies to support reliability regardless of the final resource mix.

CALIFORNIA GAS RETIREMENTS SENSITIVITY

Gas retirements could occur for a variety of reasons, such as environmental justice concerns or insufficient revenues. This sensitivity analyzes how in-state gas retirements may impact the ability to serve load. With the exception of the Diablo Canyon Nuclear Plant, remaining once-through cooling units, and announced retirements, we did not consider any additional retirements of existing conventional generation in any of the portfolios (leaving approximately 24 GW of in-state gas capacity).

In this sensitivity, we removed approximately 11.5 GW of natural gas capacity from the California gas fleet by removing steam gas units (~500 MW) and combined cycle gas generators operating at less than 20% capacity factors. To address environmental justice concerns, we mapped our gas retirements to California-based environmental justice screens to compare candidate lists and capacity by region.

LOW HYDRO AVAILABILITY SENSITIVITY

This sensitivity evaluates the impact of low hydro availability on California's power system. In recent years California and the western United States has regularly experienced severe drought which has depleted reservoirs and limited hydro availability. The drought concern is most acute during the late summer months, which tends to align with peak load conditions. The baseline assumptions used across each scenario were representative of a normal hydro year (monthly 15-year rolling average), and slightly below the 20-year average monthly generation. The low hydro availability sensitivity used the 10th percentile of hydro conditions from 2001-2020, based on annual energy, corresponding to the 2020 hydraulic year (Figure 10).[32]

32 The year 2020 reflects the 10th percentile over the years from 2001-2020 based on an annual energy basis (it ranked as the third lowest year with 2014 and 2015 being lower). Hydro data from 2021 was not available at the time the analysis was conducted.

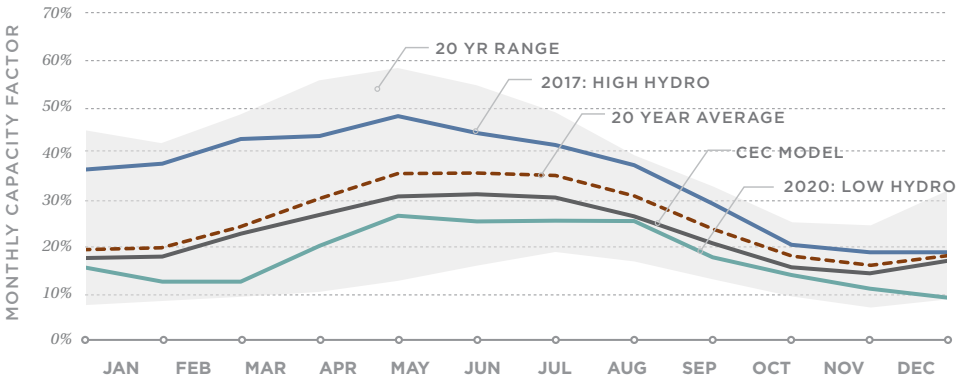


FIGURE 10.

California Monthly Hydro Capacity Factor across 20-years

WESTERN COAL RETIREMENT SENSITIVITY

California is highly interconnected with the rest of the Western Interconnection and regularly imports electricity, including dedicated capacity contracts to meet resource adequacy requirements. Even in the high renewable portfolios evaluated in this study, California imports more electricity than it exports over the course of 2030. As a result, the availability of resources across the Western Interconnection is important to informing resource adequacy in California.

This sensitivity explores the impact of accelerated coal retirements across the west, recognizing that neighboring regions may choose to decarbonize their generation mix more quickly than we assumed in our portfolios (which considered, only, announced coal retirements). All but two states in the west have renewable energy standards—near-term goals range from 15% (Arizona) and 20% in 2025 (Utah), to 60% (California) and 50% (Nevada) by 2030; and long term RPS goals—including 100% by 2050 (Colorado and Nevada), 80% by 2040 (New Mexico), and 100% by 2045 (California and New Mexico).[33] A growing number of states are adopting 100% clean electricity or net-zero emissions targets—100% by 2040 (Oregon and Nebraska[34]), 100% by 2045 (Washington, California, New Mexico), 100% by 2050 (Colorado, Nevada).[35] And some of the largest utilities have adopted similar voluntary goals, including Arizona Public Service and Idaho Power.[36] Most have announced coal retirements or are under pressure to retire these in the near future. In this sensitivity, all remaining coal in the model across the west—14.3 GW—was replaced with a portfolio of wind, solar, and storage resources to replace

33 See the DSIRE database https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2020/09/RPS-CES-Sept2020.pdf

34 The boards of Nebraska's three publicly owned utilities have set carbon free electricity targets for 2040 (Lincoln Electric) and 2050 (Omaha and Nebraska Public Power Districts).

35 See the Clean Energy States Alliance tracker. https://www.cesa.org/projects/100-clean-energy-collaborative/guide/map-and-timelines-of-100-clean-energy-states/

36 See https://www.aps.com/en/About/Our-Company/Clean-Energy and https://www.idahopower.com/news/idaho-power-sets-goal-for-100-percent-clean-energy-by-2045/

the annual energy generated by the coal fleet.[37] We excluded any new gas or firm renewable resources from replacing the retired coal. This sensitivity can be viewed as a conservative approach since various utility IRPs have proposed natural gas replacement capacity. The change in the installed capacity by region is listed in Table 3.

TABLE 3.

Change in Installed Capacity for WECC Coal Retirement and Replacement Sensitivity

REGION	RETIRED COAL CAPACITY (GW)	ADDED CAPACITY (GW)			
		WIND	SOLAR	BATTERY STORAGE	TOTAL
Rocky Mountains	10.1	9.7	3.3	1.6	14.6
Southwest	4.2	1.4	4.5	2.2	8.1
Total WECC	**14.3**	**11.1**	**7.7**	**3.9**	**22.6**

CALIFORNIA IMPORT SENSITIVITY

This sensitivity tests California's dependence on import availability by restricting the total imports allowed into California. Limitations in imports could be caused by a range of factors, including generator retirements, transmission outages, high loads, or other reasons for scarcity. In this sensitivity, we restricted total net imports (including both dedicated and economic imports) to 13,100 MW during summer peak load hours. This value was selected because it was consistent with the stress condition already in the CEC PLEXOS database and is generally consistent with the level of historical imports during times of tight supply conditions.[38]

MULTIPLE WEATHER YEAR LOAD VARIABILITY SENSITIVITY

This sensitivity characterizes the combined impact that weather variability will have on load and renewable output. Unless stated otherwise, all the production cost simulations use a fixed demand forecast (California Energy Demand IEPR forecast 2020 mid-mid case) that represents an "expected" weather year.[39] However, system reliability is significantly affected by extreme weather, especially during summer months. This was particularly true in the August 2020 rolling blackouts, which experienced an extreme heat wave that led to higher than expected peak load conditions.

37 Wind and solar generation was built to replace the energy from the coal-fired power plants. New battery storage resources were installed at 50% of the new solar capacity and assumed to have a 4-hr duration.

38 The CEC PLEXOS database had a 13,100 MW import limit during 5 peak hours in 2030; this sensitivity extended this limit to all peak hours in the summer (roughly 10am-8pm daily).

39 The primary reason for this approach was that we did not have weather correlated IEPR load data across all months for 2030.

We conducted two types of analysis:

1. The first analysis used a multi-year analysis that examined the impacts of varying summer load (May through October) based on load forecasts calibrated to 20 historical weather years. This dataset was developed for 2026 by the CEC and consisted of the six summer months of load only (May through October).[40] We scaled the 2026 data to approximate a 2030 dataset based on a comparison of the CED IEPR mid-mid case comparisons between 2026 and 2030.[41]

   The demand data were combined with solar and wind data to represent internally consistent demand, solar and wind data sets, and a set of model sensitivities were run across the full 20-year horizon. We used solar data that matched the 20 historical weather years. Due to wind data limitations, we conducted two sets of analysis: (1) a single weather year for wind data (2012) that is held constant across the 20 years of coincident load and solar data that represents the lowest wind availability between July and September across the 8-year sample; (2) eight years of synchronized wind, solar, and load from 2007-2014.

2. The second analysis consisted of recreating the August 2020 event conditions. Because we did not have 2020 weather year based projections in the multi-year data set, we identified conditions similar or worse than the August 2020 event, and created a "proxy August 2020 event in 2030". We conducted additional simulations for this "proxy August 2020 event in 2030" to exercise the system against three different "import restriction levels (8,000 MW, 4,000 MW, and 0 MW) applied to economic and non-renewable dedicated imports.

40 California Energy Commission Staff. Hourly Demand Distribution for May -October, 2021-2026, an unsupported product. This data was generated by the CEC for the California Midterm Reliability Resource analysis.

41 CEC load forecasts consist of two broad categories: "unadjusted" consumption and numerous "load modifiers" (such as BTM solar, energy efficiency, electric vehicles). Per communication with the CEC, the unadjusted consumption components are assumed to be weather dependent, while the load modifiers are assumed to be independent of weather. We scaled the hourly "unadjusted" consumption component from the 2026 summer months data set, for all 20 weather years, with daily energy scaling factors that compare the unadjusted consumption components of the 2030 and 2026 mid-mid demand forecasts; the daily energy scalars maintained the weather-based load variability in the original data set.

DEMAND FLEXIBILITY SENSITIVITY

The Demand Flexibility sensitivity is designed to assess the benefits that load shifting can play in the future power system. With a future resource mix of increasing reliance on variable renewable energy, load flexibility may be beneficial to balancing supply-side variability. All baseline simulation conditions assume the availability of traditional "shed" based demand response which curtails load at high prices and scarcity events, but not load shifting which moves load over the period of a few hours from one time period to another, providing both a capacity and energy service to the grid.

This sensitivity leveraged data from the Lawrence Berkeley National Laboratory's (LBNL) *California Demand Response Potential Study*,[42] to reflect shift potential for the Base Case Portfolio and the Diverse Clean Resources Portfolio. The top four flexible resource types identified in the LBNL study include industrial processes, pumping loads, heating ventilation and air conditioning (HVAC), and electric vehicles. Our analysis relies on the Medium Technology Scenario using 1-in-2 weather assumptions at an annualized resource procurement cost of 150 $/yr/kWh. Using the LBNL study, the amount of energy per shift event was derived (Table 4). The maximum shift potential in an hour was calculated assuming an average shift event of two hours.

TABLE 4.

Average Load Shift Parameters by End-use Type

RESOURCE TYPE	DAILY PEAK SHIFT MW	DAILY ENERGY MWH
EV Charging	63	125
HVAC	1,175	2,350
Industrial Processes	1,388	2,775
Pumping Load	465	930
Total	**3,090**	**6,180**

In the PLEXOS model, flexible loads are defined as batteries subject to special constraints. In our analysis, each resource was assumed to support one shift event per day (one battery cycle) and was not allowed to shift energy from one day to the next. All flexible loads were assumed to be 100% efficient except for flexible HVAC which assumed a non-unity discharge efficiency[43] to reflect thermal losses of conditioned spaces. Using the embedded or derived load forecasts for each flexible load resource, we developed monthly rating factors to adjust the available shift

42 Gerke, et al., The California Demand Response Potential Study, Phase 3: Final Report on the Shift Resource through 2030, Lawrence Berkeley National Laboratory, July 2020, https://emp.lbl.gov/publications/california-demand-response-potential

43 A discharge efficiency of 80% was used, this is based on personal estimates from observations of additional heating/cooling after a shift event.

energy, reflecting that some loads may have higher utilization in certain months (namely, HVAC load has up to 3600 MWh of shiftable load in the summer due to cooling compared to 1300 MWh in the winter). To reflect imperfect foresight, rating factors were calculated for every hour of each month to adjust how much flexible load is available in a given hour.[44]

When we modeled the High Electrification portfolio, we assumed less conservative assumptions for the amount of flexible load available in the Demand Flexibility sensitivity: We assumed that up to 20% of the newly added electrified building load and electric vehicle load are flexible (Table 5).

TABLE 5.

Average Flexible Load Parameters in High Electrification portfolio

RESOURCE TYPE	DAILY PEAK SHIFT MW	DAILY ENERGY MWH
EV Charging	6,250	12,500
HVAC	7,500	15,000
Industrial Processes	1,388	2,775
Pumping Load	465	930
Total	**15,603**	**31,205**

44 A possible refinement to this approach would be to input the maximum coincident load for a resource type and to define the load take and shed relative to it, instead of a calculated average value for each month.

COMBINED STRESSOR SENSITIVITY

The objective of the Combined Stressor sensitivity is to understand the interactive and compounding effects of multiple system stressors on the power system. To evaluate this effect, a sensitivity was conducted that applied all previous challenging sensitivities in combination. We conducted simulations across 20 weather years using the following assumptions:

- California in-state natural gas retirements of 11.3 GW
- Total imports limited to the value that is consistent with the CEC's PLEXOS model and similar to historical peak-hour imports (13 GW)
- Drought conditions across California, assuming a 10th percentile (P10) of hydro conditions based on monthly available energy over the past 20 years
- Coal Retirements across WECC and replaced with renewables and energy storage
- May through October load based on 20 different weather years to better capture the effects of inter-annual load variability and extreme weather events

These simulations were conducted for May through October due to the load data limitations for the 20 different weather years that corresponded to these months. Given that 2030 winter peak demand is projected to be approximately 24 GW lower than summer peak and import availability is likely higher during the winter months due to surplus capacity across WECC, this was determined to be a reasonable simplification; however, full year data sets should be evaluated in future studies.

DESCRIPTION OF MODELING OUTPUT METRICS

The combination of portfolios and sensitivities resulted in 200+ years of simulations equivalent to over 1.7 million hours of simulated chronological commitment and dispatch of the western grid. To synthesize the very large number of simulated results, we identified a collection of primary metrics to capture the most relevant aspects of the production cost modeling. These metrics include:

- RPS and clean electricity attainment
- Net generation by resource type
- Net interchange by import/export type
- Natural gas margin (a metric that we developed specifically for this study)
- WECC hourly reserve margin

Each metric is described below with illustrations from the Base Case portfolio analysis.

RPS AND CLEAN ELECTRICITY ATTAINMENT

The two clean electricity metrics we calculate are the state renewable portfolio standard percentage attainment (RPS%) and the total clean electricity percentage attainment (Clean Electricity %). The RPS % excludes large hydro and non-compliant resources (i.e., municipal solid waste). The Clean Electricity % includes all zero-carbon resources and is approximately 10% higher on an annual energy basis (owing primarily to the contribution of large hydro generation[45]). Both of these metrics are calculated as a percentage of retail sales. In the Base Case and Diverse Clean Resources portfolios, total retail sales in California are approximately 240 terawatt hours (TWh) in 2030, and represents 77% of the total annual load energy. The use of retail sales in the calculation follows California statute, which excludes BTM solar, transmission and distribution losses, round-trip energy losses for battery storage, and certain pumping, agricultural, and municipal loads.

45 As noted, all the simulations, but for the low hydro sensitivity, assumed a "normal" hydro year, which is slightly below the 20-year average. The difference between the RPS and clean energy percentage would vary more significantly on an actual basis, according to inter-year hydro availability (approximately +/- 5%).

$$RPS\ \% = \frac{utility\ scale\ renewable\ generation}{retail\ sales}$$

where retail sales = gross load net of BTM solar; excludes certain pumping, agricultural, municipal loads, transmission, distribution, and round-trip storage losses

$$Clean\ electricity\ \% = \frac{utility\ scale\ renewable\ generation + non\text{-}renewable\ zero\ carbon\ resources}{retail\ sales}$$

where non-renewable zero carbon resources mainly consists of large hydro generation, but could include nuclear generation if evaluated in a portfolio; the denominator is consistent with the denominator in the RPS % metric

All the portfolios and sensitivities achieve, approximately, a target of 75% RPS and 85% clean electricity.

We calculate a third metric, called clean generation %, which calculates the amount of generation served by clean resources, inclusive of behind the meter solar PV, transmission and distribution losses, and round-trip efficiency of storage. This metric is calculated as follows:

$$Clean\ generation\ \% = \frac{utility\ scale\ renewable\ generation + non\text{-}renewable\ zero\ carbon\ resources + net\ energy\ storage + BTM\ solar}{gross\ load}$$

where gross load includes transmission and distribution losses

We achieve approximately an 80% clean generation target.

A summary of the policy target metrics are provided in Table 6 and Figure 11. There are some differences in the policy targets achieved among the different portfolios and across weather years due to inter-year weather variability, curtailment (only delivered renewable energy is counted), and battery utilization. The High Electrification portfolio achieves slightly lower levels of RPS % but significantly lower levels of clean %, relative to the other portfolios. This is because the target we modeled in RESOLVE was a 75% RPS target, rather than an 85% clean electricity target. RESOLVE built a proportionally higher amount of renewable energy to meet the higher levels of load in the High Electrification portfolio, but not a higher level of clean/non-renewable resources to meet this additional load. In the Base Case portfolio, the large hydro contribution resulted in a clean electricity % of approximately 85%, which is roughly 10 percentage points higher than the RPS%; whereas, in the High Electrification portfolio, the contribution of large hydro generation, relative to retail sales, is smaller than 10 percentage points. This raises an important policy consideration that targets should be explicitly set to the objective they are aiming for (i.e., renewable vs. clean electricity).

TABLE 6.

Description of RPS, clean electricity and clean generation metrics

TARGET METRIC	DENOMINATOR	INCLUDED RESOURCES
75% RPS	End use sales based on existing RPS statute (~240 TWh)	In-state and contracted out of state utility-scale wind and solar resources, small hydro, and eligible biomass, MSW, etc.
85% Clean	End use sales based on existing RPS statute (~240 TWh)	All resources included in the RPS calculation, plus large-scale pondage hydro and some ineligible MSW and biomass resources which are excluded from the RPS statute
80% Clean Generation	Total load, including BTM solar, and scaled up for T&D losses (~308 TWh)	All resources included in the clean metric, plus BTM PV and round-trip energy losses for storage

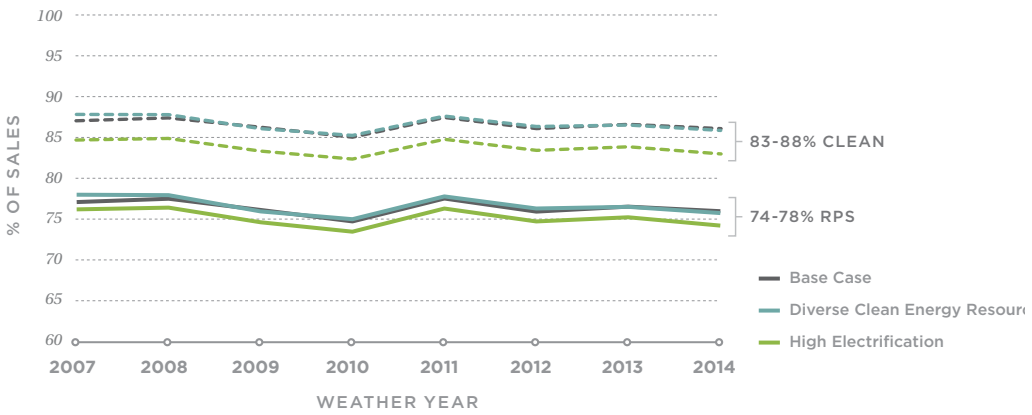


FIGURE 11.

RPS % and Clean Electricity % in 2030 by portfolio

NET INTERCHANGE BY IMPORT AND EXPORT TYPE

California has historically been a large importer of electricity, constituting 20% of the total California electricity mix in 2020.[46] In recent years there has been a small amount of exports during high solar events, but this has been historically a small amount of the overall electricity mix and is limited to approximately 4,000 MW by the CAISO in any hour. The overall interchange and net imports are expected to increase in the coming years for various reasons, including the expansion of the CAISO Energy Imbalance Market to new entrants and integrating day ahead commitment and dispatch (Extended Day Ahead Market, or EDAM); the retirement of OTC units and Diablo Canyon; and the increased saturation of solar capacity.

46 California Energy Commission, 2020 Total System Electric Generation, https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2020-total-system-electric-generation

Given the importance of net imports, we quantified three different types of net imports:

- **Non-RPS Dedicated Imports:** electricity sourced from known generators with long-term power purchase agreements or resource adequacy contracts. These represent units with full or partial remote ownership located across the West; this information was included in the original model from CEC.
- **RPS Imports:** electricity sourced from utility-scale wind, solar, and other renewable generators located across the West that are contracted to meet in-state RPS targets. This includes new generation resources built by RESOLVE for serving California load.
- **Economic Imports:** electricity that flows into or out of California based on economics and the real-time price of electricity. If surplus capacity is available outside of California at a lower price than the marginal in-state resource (often in-state natural gas), the model will import electricity from available, non-dedicated, resources. This is a proxy for the energy imbalance market.

For the Base Case portfolio, imports are 19% (non RPS-dedicated imports), 58% (RPS imports), and 23% (economic imports) of total net imports. The High Electrification portfolio has the highest utilization of economic imports (~ 30%) and the Diverse Clean Resources portfolio has the lowest (~ 20%). Among the three portfolios, the annual net imports and economic imports exhibit little variation as a percentage of annual load (differing by less than 2%), but there may be periods that require more economic imports during times of system stress.

TABLE 7.

Overview of Annual Net Imports by Classification, by portfolio

	BASE CASE PORTFOLIO	DIVERSE CLEAN RESOURCES PORTFOLIO	HIGH ELECTRIFICATION PORTFOLIO
NET IMPORTS (THOUSAND GWH)			
Non-RPS Dedicated Imports	16.0	16.1	16.1
RPS Imports	48.9	45.2	49.2
Economic Imports	18.8	15.8	26.3
Total imports	**83.7**	**77.2**	**91.6**
PERCENT OF NET IMPORTS			
Non-RPS Dedicated Imports	19%	21%	18%
RPS Imports	58%	59%	54%
Economic Imports	23%	21%	29%
Total Imports	**100%**	**100%**	**100%**
PERCENT OF ANNUAL LOAD			
Non-RPS Dedicated Imports	5%	5%	5%
RPS Imports	16%	15%	14%
Economic Imports	6%	5%	7%
Total Imports	**27%**	**25%**	**26%**

NATURAL GAS MARGIN

The use of economic imports is of particular interest in this study because, while economic imports are a resource available to California, they are not contracted resources. From a reliability perspective, if these imports are being relied on during supply-scarce events, there is no guarantee of them being available if neighboring regions are also experiencing tight supplies.

However, economic imports should not be viewed only negatively. Under most circumstances the availability of economic imports represents the economic efficiency of interregional coordination and geographic diversity. In most cases, economic imports are directly substitutable for in-state natural gas resources, and the decision to use economic imports instead of in-state natural gas resources is an economic one. Since in-state natural gas resources and economic imports are largely interchangeable, it is helpful to view these resources collectively, as shown below. Figure 12 shows the hourly average use of economic imports, in-state natural gas, and the sum of these across all months for the Base Case.

FIGURE 12.

Heatmap of Average In-State Gas Dispatch and Economic Imports by Month and Hour (Base Case portfolio with Baseline sensitivity assumptions)

From a reliability standpoint, however, it is important to distinguish between those imports used for economic efficiency (displacing in-state gas resources), versus imports that are used because they are needed for reliability purposes (to avoid being forced to rely on load shedding in California). To do this, we combined the in-state natural gas resources and the economic imports on an hourly basis, and compared this total to the available in-state natural gas capacity on an hourly basis. The available in-state gas capacity fluctuates throughout the year(s) due to sampling forced outages (fluctuations throughout the year), planned maintenance (i.e., lower availability in spring and fall months), and ambient derates during summer months. The natural gas margin quantifies the surplus in-state gas capacity available to California if the economic imports from neighboring regions (without a contract associated) are unavailable. The natural gas margin is an informative reliability metric that we track across all portfolios and sensitivities.

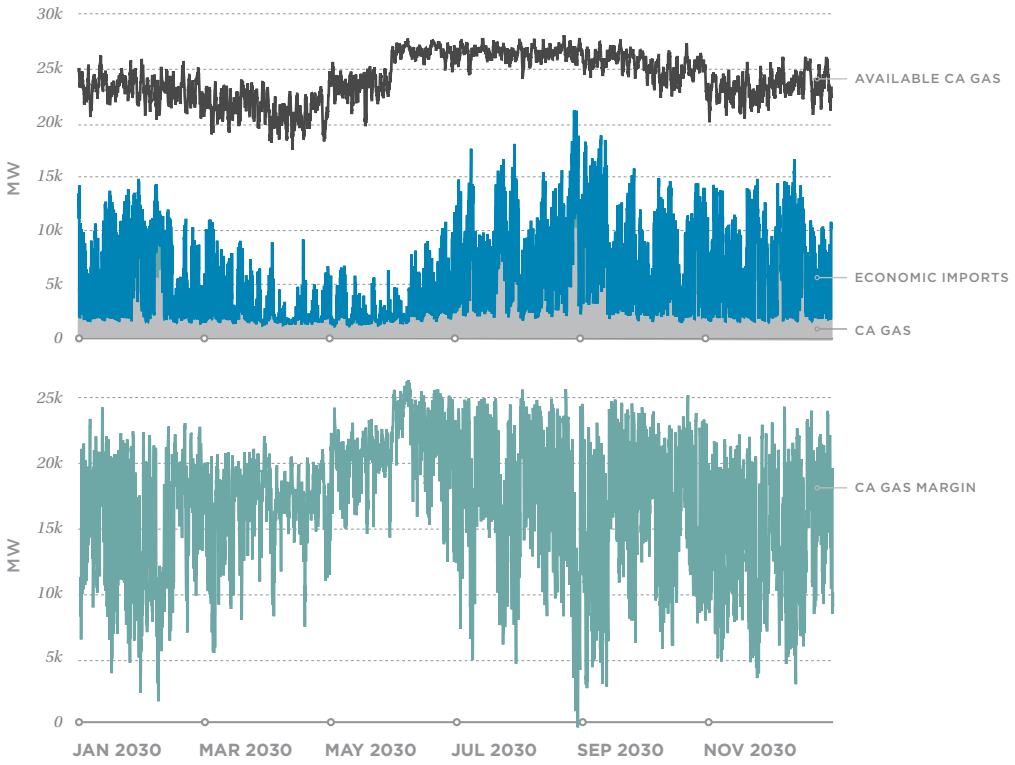


FIGURE 13.

Quantification of Natural Gas Margin Across an Entire Year (Base Case, Weather Year 1)

The top frame of Figure 13 shows the combined economic imports and in-state natural gas dispatch relative to the available in-state natural gas capacity. The natural gas margin, which is the difference between the available capacity and the combined generation from these resources, is shown in the bottom pane. This represents over 70,000 data points (8 weather years x 8760 hours). We show summary statistics of the gas margin by season in Figure 14.

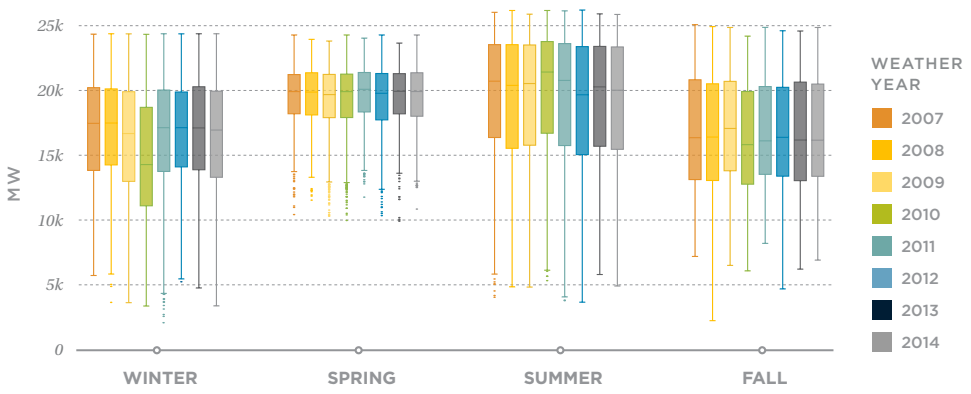


FIGURE 14.

Summary of Natural Gas Margin in Base Case by Weather Year; the box represents the 25th, 50th, and 75th percentile of observations and the whiskers capture observations within 1.8x of the interquartile range. Dots represent individual outliers that do not fall within this range.

We observe that there is no unserved energy for all three portfolios. This result is not surprising given that in-state natural gas resources are retained in most of the portfolios and sensitivities and that imports from neighboring regions are available. The hourly natural gas margin is a proxy for overall tightness of supply during risk periods and is a metric we use in lieu of traditional metrics commonly used in resource adequacy analysis, such as expected unserved energy and loss of load expectation. We recognize that dependence on economic imports (as indicated by a negative gas margin) is not necessarily a problematic condition, if the rest of the WECC has sufficient resources to supply exports to California. As such, the WECC hourly reserve margin (described next) is an important metric that should be viewed in concert with a negative gas margin.

WECC HOURLY RESERVE MARGIN

We developed an additional reliability metric "WECC-wide hourly reserve margin," or "WECC hourly reserve margin" for short to represent how much resource capacity remains across the entire west, **excluding California**. This is calculated for each hour of the year so that the net imports into California can be evaluated against the availability of surplus capacity in other regions in the WECC.

The purpose of this metric is to characterize the use of economic imports relative to reliability.

It is risky for California to use economic imports heavily during times when neighboring regions have little surplus capacity; economic imports could be unavailable when needed and California should have in-state gas resources (or other clean-firm resources) available to replace the imports as required. **If, however, California is using economic imports during times of surplus capacity across the**

WECC, this represents a prudent economic decision and should not be viewed negatively from a reliability perspective. As the WECC hourly reserve margin increases, and if the WECC hourly reserve margin is greater than 0%, the region has some excess capacity, even if the gas margin is negative (meaning that California is reliant on non-dedicated imports during some time periods).

The WECC hourly reserve margin is calculated by quantifying the total available capacity in each region outside of California, where available capacity is based on the installed capacity for thermal resources, wind and solar resource weather dependent profiles, and the dispatched capacity for hydro and energy storage resources. The total available capacity is then divided by the non-California system load to cover the capacity reserves into a percentage of demand and is a measure of surplus capacity, after exports to California are accounted for. To capture the surplus component of the total available capacity, 100% is subtracted from the percentage. The hourly WECC hourly reserve margin is shown for the 2010 weather year in Figure 15.

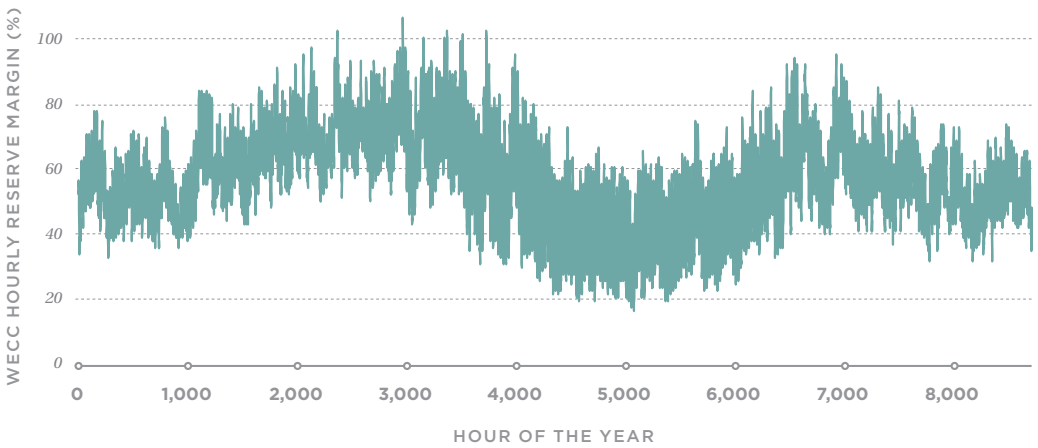


FIGURE 15.

One Year of Chronological Hourly WECC Hourly Reserve Margin, Base Case, Baseline Assumptions

This shows a seasonal pattern where reserves are highest, on average, during the spring months that experience high wind availability and high hydro availability due to spring snowmelt and run-off conditions. The lowest periods occur during the summer peak demand periods across much of the WECC. The figure shows that minimum hourly reserve margins rarely drop below 20% of hourly demand, and are often well above that level. This suggests that on a WECC-wide basis, there is sufficient capacity available to cover higher than expected load conditions and low available renewable resources.

It is useful to compare the WECC hourly reserve margin with economic imports into California, as it measures the amount of surplus capacity that is available in

other regions that are exporting power. If there are periods where California is importing a large amount of power that is not tied to a specific contracted resource located in another region, and the WECC hourly reserve margin is low, this could represent a challenging operating condition where the imports may not be available to California. Note that this risk is also captured in the Gas Margin metric, which calculates the available gas capacity to cover for the loss of economic imports.

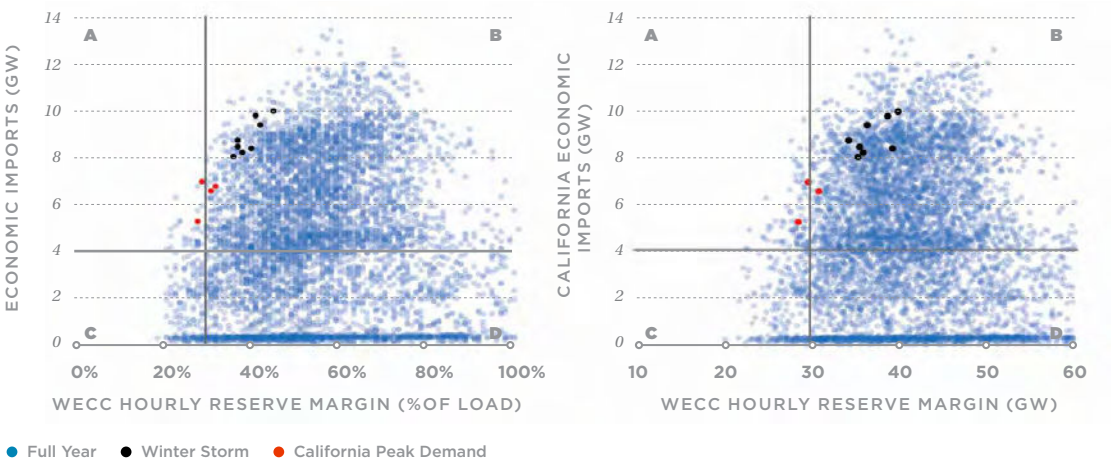


FIGURE 16.

Hourly California Economic Imports versus WECC Hourly Reserve Margin (Base Case Portfolio with Baseline Assumptions)

Figure 16 shows a scatter plot of the hourly California economic imports relative to the WECC hourly reserve margin for one year of operation in the Base Case under Baseline assumptions. The plot is divided into quadrants, where the upper left quadrant ("A") represents relatively high economic imports and low WECC hourly reserve margins, and thus an increased risk of the imports being unavailable. The upper right quadrant ("B") represents high imports during periods of higher reserve margins. The lower quadrants represent periods of lower relative imports. This plot also highlights periods from a winter storm with a multi-day low wind and solar event in California, as well as the California peak load event for reference.

KEY INSIGHTS ACROSS PORTFOLIOS AND SENSITIVITIES

FINDING 1. **Reaching 85% clean electricity is feasible and reliable**

California can reliably meet an 85% clean electricity standard by 2030 through multiple resource pathways, which are based primarily on wind and solar generation, and battery storage.

SUMMARY RESULTS

The analysis in this study illustrates that California can reliably achieve an 85% clean electricity standard and an accelerated 75% renewable portfolio standard (excluding large hydro resources) by 2030 and there are multiple options available to the state. The main contribution of this study is to assess the operational performance of three 85% clean portfolios using production cost modeling. Our production cost modeling shows that a system with this amount of renewables can be both operational and resource adequate across all hours and days of the year, and when considering inter-annual weather variability.

Table 8 summarizes the results across portfolios and sensitivities. Each metric represents what is observed across the different weather years (i.e., the median represents the median across the weather years, the spread reflects the range across the different weather years, and the lowest value represents the lowest across the weather years).[47]

47 The spread is based on the difference between the minimum and maximum observations; the lowest value is defined as the 0.1 percentile.

TABLE 8.

Comparison of key select metrics for all portfolios and sensitivities across multiple weather years

		RPS (% of Sales)		Clean Electricity (% of Sales)		Minimum Gas Margin (GW)		WECC Hourly Reserve Margin during periods of Minimum Gas Margin		Minimum WECC Hourly Reserve Margin (% of Load)		California Gas Margin during periods of Minimum WECC Hourly ReserveMargin (MW)		Number of Low Wind and Solar Events (Consecutive 3-days Below 30% of Load)	
	SENSITIVITY	MEDIAN	SPREAD	MEDIAN	SPREAD	MEDIAN	LOWEST	MEDIAN	LOWEST	MEDIAN	LOWEST	MEDIAN	LOWEST	MEDIAN	LOWEST
BASE RESOURCE PORTFOLIO	**Baseline**	**76**	**2**	**87**	**2**	**7.9**	**7.5**	**53%**	**36%**	**25%**	**23%**	**23**	**21**	**10**	**4**
	WECC Coal Retirement	76	2	86	2	8.1	7.7	38%	29%	17%	16%	21	20	10	4
	Gas Retirement	76	2	87	2	(1.4)	(1.7)	48%	30%	24%	23%	8	12	10	4
	Low Hydro	76	2	84	2	7.1	6.3	62%	58%	24%	23%	21	21	10	4
	Multiple Load Years	76	2	87	2	4.5	1.9	62%	62%	23%	21%	22	15		
	Joint Sensitivity	76	2	86	2	(6.1)	(8.5)	47%	56%	16%	14%	9	3		
DIVERSE CLEAN RESOURCES PORTFOLIO	**Baseline**	**76**	**2**	**87**	**2**	**9.2**	**8.6**	**49%**	**56%**	**25%**	**23%**	**21**	**13**	**13**	**7**
	WECC Coal Retirement	76	3	86	3	9.3	8.8	31%	30%	18%	16%	20	20	0	0
	Gas Retirement	76	2	87	2	(0.5)	(0.8)	41%	36%	25%	23%	12	7	13	7
	Low Hydro	76	2	84	2	8.1	7.8	47%	42%	25%	23%	22	17	13	7
	Multiple Load Years	77	2	87	2	5.1	3.2	52%	44%	23%	22%	22	24		
	Joint Sensitivity	76	2	86	2	(5.3)	(7.5)	42%	53%	16%	14%	9	2		
HIGH ELECTRIFICATION PORTFOLIO	**Baseline**	**75**	**2**	**84**	**2**	**5.0**	**3.8**	**50%**	**37%**	**25%**	**24%**	**20**	**21**	**16**	**5**
	WECC Coal Retirement	75	2	83	2	4.8	4.0	36%	33%	18%	16%	18	22	16	5
	Gas Retirement	75	2	84	2	(3.9)	(4.8)	45%	37%	25%	24%	10	5	16	5
	Low Hydro	75	2	82	2	4.0	2.7	42%	40%	25%	24%	19	18	16	5
	Multiple Load Years	75	2	84	2	3.1	0.9	56%	59%	23%	22%	20	23		
	Joint Sensitivity	75	2	83	2	(6.7)	(9.5)	42%	48%	17%	14%	9	9		

Note: The minimum gas margin and minimum WECC hourly reserve margin is reflective of the 1st percentile value, to remove outliers; the values reported are either the median, or lowest value, of the 1st percentile values across all weather years.

The differences in annual renewable attainment and reliability metrics (minimum natural gas margin, WECC-wide hourly reserve margin, and number of multi-day low renewable energy events) are minimal. The metric with the largest variation is the minimum gas margin, which is the difference between the available gas capacity, and the sum of the gas dispatch and economic imports. Across most of the sensitivities, the minimum gas margin is positive. Even in the event of a negative gas margin, a positive WECC wide reserve margin indicates the rest of the region could potentially provide exports to California.

MONTHLY GENERATION

Figure 17 shows the monthly net generation by resource type for California in the Base Case portfolio. In some spring months, renewable generation represents nearly 100% of total energy and California becomes a net exporter to neighboring regions. There is a continued need for gas generation or economic imports to serve load from the summer through to winter.

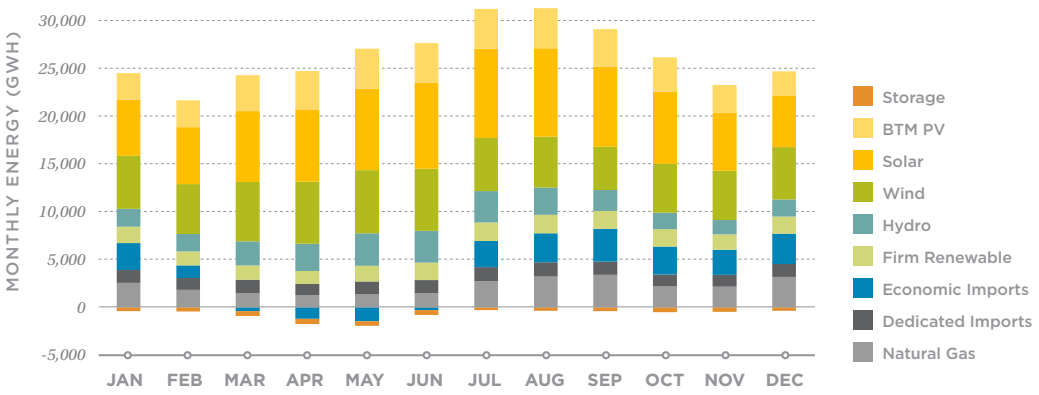


FIGURE 17.

California Monthly Net Generation by Resource Type for the Base Case portfolio (reaching 75% annual RPS and 85% clean electricity)

DISPATCH RESULTS

An important contribution of this study is the assessment of operational performance of the portfolios across multiple weather years. Figure 18 shows the single peak load week for three separate weather years (out of the eight weather years evaluated) and Figure 19 shows a winter demand period for the same three weather years. Comparing these figures, both intra-year and inter-year weather variability affects how the power system is operated—including the dispatch of natural gas generation and use of economic imports, and operation of storage.

Another observation is that the winter periods show potential for multi-day low wind and solar events. Historically, while summer months have been associated with increased resource adequacy risk, in the future, winter months may pose an increased reliability challenge as the power system becomes increasingly reliant on variable renewable energy and energy limited resources.

FIGURE 18.

Chronological Hourly Dispatch Across Six Peak Load Days and Three Weather Years

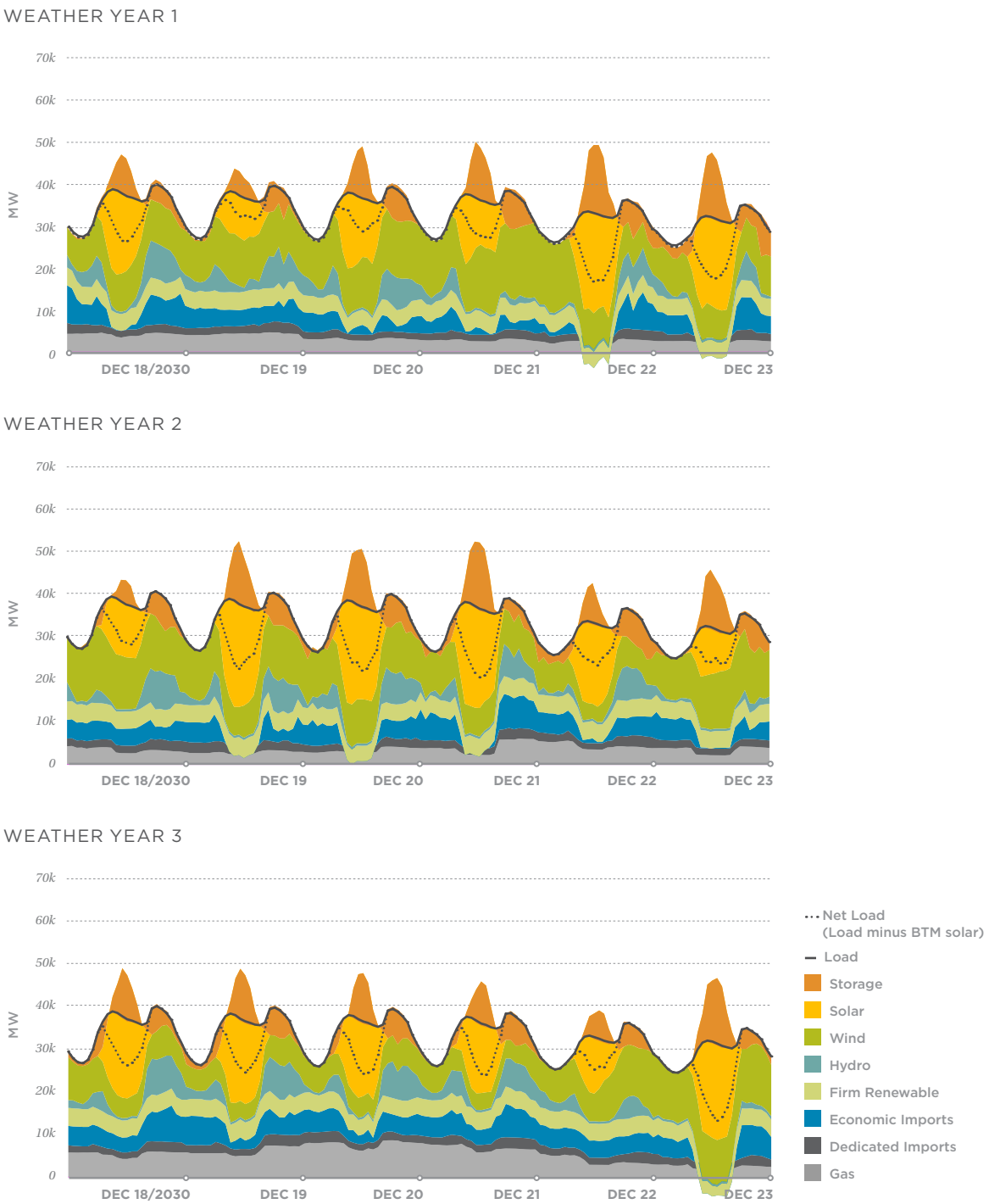


FIGURE 19.

Chronological Hourly Dispatch Across Six Winter Load Days and Three Weather Years

STORAGE AS THE KEY ENABLER

The dispatch figures of our modeled 85% clean power system show that battery energy storage is the key enabler for reliable operation of 85% clean energy portfolios. With between 11-15 GW of additional storage capacity between now and the 2030 portfolios, storage represents the largest change (relative to installed capacity) of any resource on the system. What becomes clear in the dispatch figures is the reduction in evening net peak demand, which is evident, also, during low wind and solar events.

To isolate the impact of the battery energy storage, Figure 20 shows the average summer net load curve (load minus BTM solar, utility-scale solar, and wind) with and without battery energy storage. Storage not only defers or reduces the need for installed gas capacity to reduce net peak demand, but also significantly reduces the additional ramping requirements on the system. For example, the evening net load ramp, which today is served by natural gas units, hydro, and imports, is reduced from an average of 26.8 GW over a three hour period to 15.5 GW. This is a reduction in the "duck curve" ramping requirements of 42% on average. In addition, battery storage becomes the primary balancing resource for wind and solar variability and provider of spinning and regulation reserves.

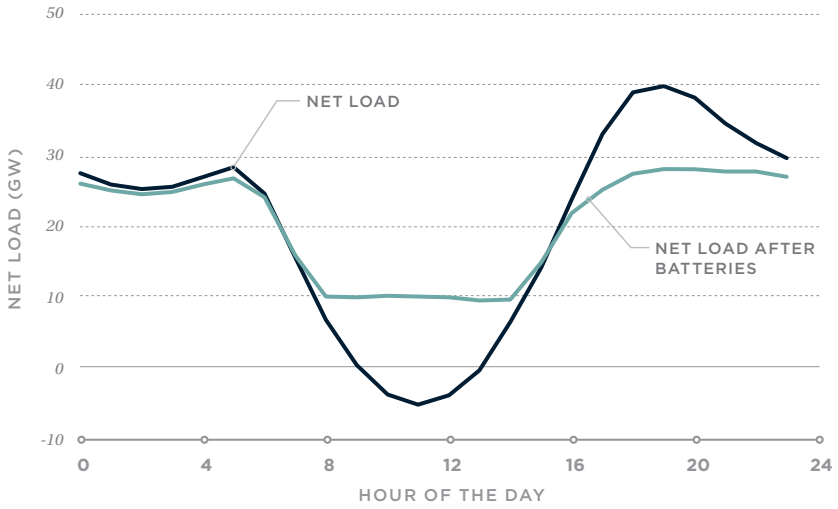


FIGURE 20.

Average Daily Summer Net Load "Duck Curve" with and without Battery Storage, Base Case (net load is gross load minus all renewables)

While the portfolio planning used in this analysis was based on annual energy targets (i.e., 75% RPS or 85% clean) it is important to also consider the needs for enabling technology, including but not limited to battery energy storage. These resources provide not only a way to shift renewable energy from one time period to another, but reduce the need for natural gas to provide firm capacity, reduce ramping requirements on other resources, and become the largest provider of grid reliability services.

FINDING 2. **A diverse clean portfolio has reliability and development benefits**

Diverse clean resources (e.g., offshore wind, geothermal) help reduce the levels of solar and storage needed to achieve clean electricity goals. They will be increasingly helpful with higher levels of demand from electrification. They also reduce dependence on gas generation and lessen the impact of inverter based resources.

Diverse clean resources can improve system reliability and provide an alternative pathway for decarbonizing the state's power system. Our analysis in RESOLVE shows that a portfolio with offshore wind and firm renewables reduces new utility solar requirements, which increases the feasibility of clean electricity targets by reducing potential land-use and transmission concerns. Under base load growth assumptions, diverse clean resources lower the new solar capacity build estimated by RESOLVE from 27 GW to 15 GW. Under high-electrification assumptions, the new utility scale solar build is lowered from approximately 40 GW to 30 GW. The original least cost portfolio identified by RESOLVE (excluding offshore wind and geothermal) estimates more than six times the amount of solar capacity (60 GW, including 20 GW of planned and 40 GW of new solar) than what has been installed over the past ten years in California. Each pathway to a clean future needs to consider potential limitations of building utility scale solar and wind due to land availability, community opposition, local congestion and transmission interconnection limits.

PRODUCTION COST COMPARISON

Figure 21 and Table 9 compare the results between the Base Case and Diverse Clean Resources portfolios (which includes 4 GW of offshore wind and 2 GW of firm renewable capacity). In the Diverse Clean Resources portfolio results, there is a reduction in monthly solar generation that is replaced by offshore wind and firm renewable energy. In-state natural gas generation is reduced during the winter months. Net economic imports are reduced by 22% over the course of the year and the combination of in-state gas and economic imports are reduced by 10% over the year. With diverse resources, load and renewable generation are more equally balanced across the year. Exports are lower during high solar events and imports are lower during low solar periods. Finally, there is a reduction in storage round-trip energy losses of approximately 50% (shown as an increase in net generation) as more renewable energy is exported directly to the grid without being cycled through batteries.

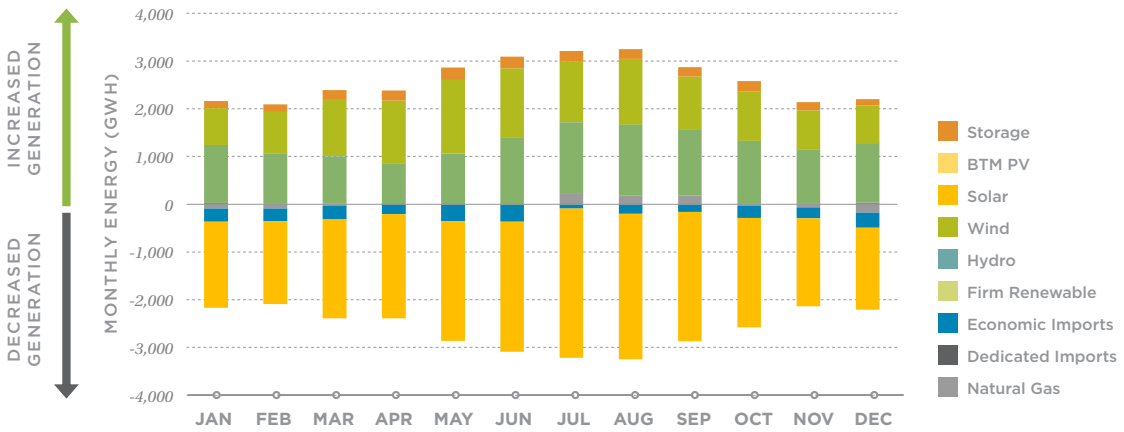


FIGURE 21.

Change in Monthly Generation between the Base Case and Diverse Clean Resources portfolios; storage represents change in round-trip energy losses. Positive values represent fewer losses.

TABLE 9.

Change in Annual Net Generation between the Base Case and Diverse Clean Resources portfolios

RESOURCE TYPE	BASE CASE PORTFOLIO (TWH)	DIVERSE CLEAN RESOURCES PORTFOLIO (TWH)	DELTA (TWH)	DELTA (%)
Gas	26.1	25.9	-0.2	-1%
Dedicated Imports	16.0	16.1	0.1	1%
Economic Imports	18.3	14.2	-4.1	-22%
Firm Renewable	20.5	35.1	14.6	71%
Hydro	29.0	29.0	0.0	0%
Wind	67.3	82.5	15.2	23%
Utility solar	91.8	63.8	-28.0	-31%
BTM solar	43.7	43.7	0	0%
Storage (round trip losses)	(5.0)	(2.6)	2.4	-48%

GAS MARGIN COMPARISON

Figure 22 compares the gas margin between the Diverse Clean Resources and Base Case portfolios. The gas margin, which represents the difference between the available in-state gas capacity relative to the gas dispatch and economic imports, is a measure of both tightness in supply and reliance on economic imports from neighboring regions. Available gas capacity refers to all in-state natural gas generators (commited or offline) that are not out on forced or planned maintenance. The distribution of hourly gas margin, across 8 weather years, is shown in Figure 22. While the high range of gas margin is relatively unchanged, there is an increase, or improvement, in the gas margin. This change is more observable in the fall and winter seasons which have the lowest outliers across the year, and there is a slight improvement during the summer peak demand period. While the majority of hours do not change significantly, the outliers are more meaningful for understanding reliability impacts, and having a 2,000 MW surplus supply cushion—even after accounting for the reduction in storage capacity in the Diverse Clean Resources portfolio—could have significant benefits during potential resource adequacy events.

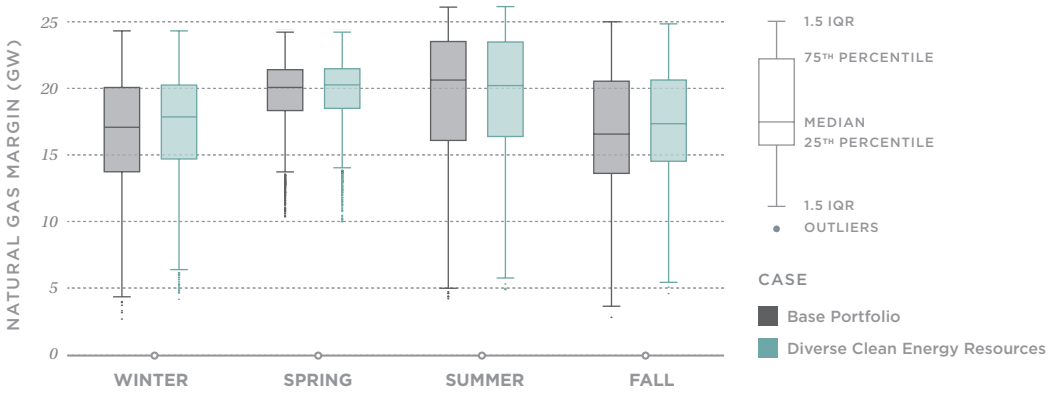


FIGURE 22.

Comparison of Natural Gas Margin by Season Base Case vs. Diverse Clean Resources portfolios

An example of the increased margin can be seen by comparing the performance of the Base Case and Diverse Clean Resource portfolios during the December 2010 weather event (Figure 23). In the Base Case portfolio, the modeled system requires a large amount of in-state gas and economic imports (nearly 15 GW). While the system still has some surplus capacity, the margin is relatively small. Further stressors like additional gas retirements, higher than expected load, and import limitations could lead to shortfalls. In the Diverse Clean Resources portfolio, however, the increased availability of offshore wind and firm renewables helps to reduce the need for in-state gas dispatch and economic imports.

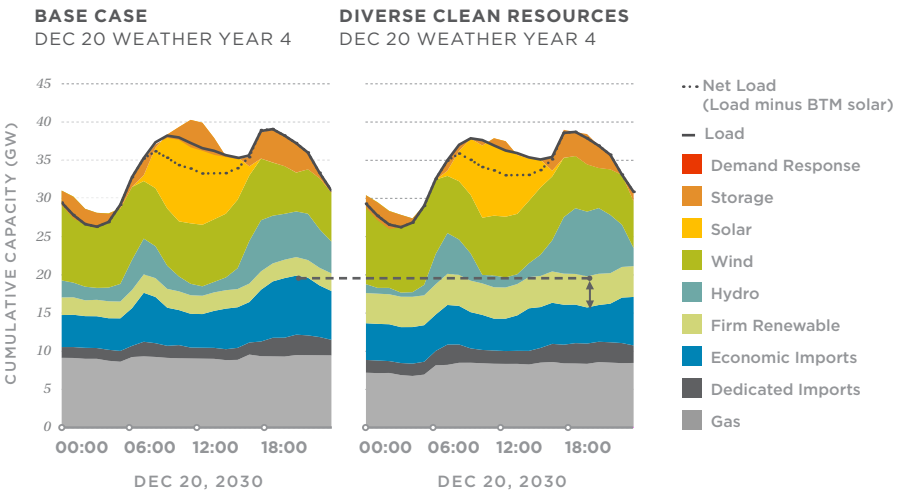


FIGURE 23.

Comparison of a Low Solar Day Dispatch, Base Case vs. Diverse Clean Resources portfolios

INVERTER BASED GENERATION COMPARISON

There is an additional benefit of the Diverse Clean Resources portfolio with respect to instantaneous inverter-based generation. In the Base Case portfolio, all the new resources (wind, solar, and battery energy storage) rely on inverter technology to interface with the grid. Inverter-based resources are asynchronous machines that do not have the same physical properties as thermal based resources. Grid-forming inverters can support grid stability when using inverter-based resources and this technology is advancing.[48] However, in the near-term, a majority of the installed fleet will be using "grid-following" inverter technology and will require a certain amount of synchronous generation in the region to operate reliably.

Although we did not assess grid stability and inverter control limitations, we calculated inverter-based resources as a percentage of total load (shown in Figure 24 as a load duration curve). In this calculation, inverter based resources include the generation from wind, solar, and battery energy storage. The industry does not yet have significant experience operating above 75% instantaneous inverter-based generation and doing so warrants further investigation and stability analysis. Note, that in April of 2021, CAISO hit its all-time instantaneous IBR penetration record of 85%.[49] This type of occurrence will become more common in the future, even as battery energy storage shifts surplus renewables from midday to evening peak periods.

48 See Lin, Yashen, Joseph H. Eto, Brian B. Johnson, Jack D. Flicker, Robert H. Lasseter, Hugo N. Villegas Pico, Gab-Su Seo, Brian J. Pierre, and Abraham Ellis. 2020. Research Roadmap on Grid-Forming Inverters. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5D00-73476. https://www.nrel.gov/docs/fy21osti/73476.pdf.

49 See CAISO, Monthly Renewables Performance Report, http://www.caiso.com/Documents/MonthlyRenewablesPerformanceReport-Oct2021.html

As Figure 24 indicates, the Diverse Clean Resources portfolio has lower instantaneous inverter-based generation relative to the Base Case portfolio because of temporal diversity and synchronous renewable generation; for example, the Base Case portfolio experiences approximately 2200 hours above 75% instantaneous inverter-based generation, while the Diverse Clean Resources case exhibits less than 1300 hours above 75%.

The addition of offshore wind resources to the Diverse Clean Resources portfolio introduces temporal diversity because these facilities generate power at different times of the day than solar resources (increasing the IBR generation in the lower hours, but decreasing it during the higher at risk periods). Firm renewable generation (which could be either geothermal or biomass) is assumed to be synchronous generation because these resources use turbine technology. While we did not specifically quantify grid stability, we estimate a 40% reduction in hours where inverter-based generation exceeds 75%. This may offer benefits towards grid stability and should be studied further.

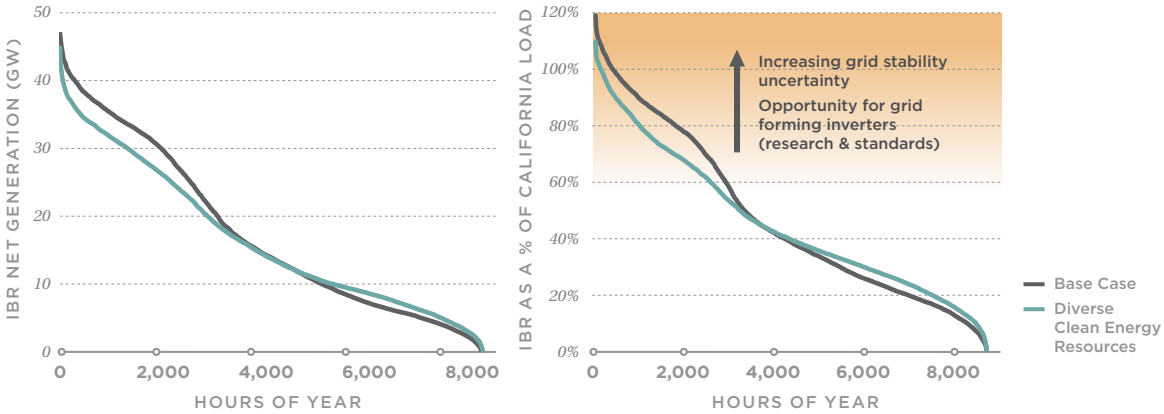


FIGURE 24.

Instantaneous Inverter-Based Generation by portfolio for the 2007 Weather Year

Although grid-forming inverter technology is advancing quickly and will enable the grid to operate reliably with less synchronous generation resources, California will still have a large installed fleet of legacy resources without grid-forming capabilities, making these considerations important for resource planning. The benefits of diverse clean resources—reduced reliance on economic imports and in-state gas resources, and lower instantaneous inverter-based generation—highlight that it is worth incorporating clean resource diversity into policy and planning. Explicitly considering resource diversity as a goal is one approach to compensate for the current limitations of planning tools and processes, particularly their inability to account for uncertainty in future technology costs, renewable resource geographic diversity, and other uncertainties. Resource diversity is unlikely to occur without direct policy or market intervention because most renewable development to date is based on the lowest levelized cost of energy. Inaction could inadvertently erode reliability and increase long-term costs.

FINDING 3. **Gas remains important but some environmental justice units could be retired**

California will need to retain a large amount of the existing gas fleet, although gas generation will be used sparingly; California can target the retirement of environmental-justice sensitive units early on and still serve load.

DISPATCH RESULTS

In-state natural gas use and economic imports are largely interchangeable from an operational perspective, and the decision to use economic imports over in-state natural gas is based on a lower relative cost of the marginal resource in neighboring regions relative to in-state natural gas plants. We introduced the gas margin concept to represent the amount of available in-state gas generation if economic imports are unavailable. A positive gas margin indicates there is additional gas generation available beyond the dispatched gas generation and economic imports, and a negative gas margin indicates the amount of economic imports that are required by California to serve load.

As shown earlier in Figure 22, under the Base Case and Diverse Clean Resources portfolios, the lowest observed margin is around 2 GW indicating that there is always enough gas generation to cover for the potential loss of economic imports and implying that the state could get by without any economic imports (those without a firm contract).

In the Base Case analysis, the fleetwide capacity factor for all types of natural gas fired power plants is approximately 10%, with combined cycle (CC) units at 15%, and steam turbine (ST) and combustion turbine (CT) generators at less than 2% each. The cumulative distribution sorted by capacity factor for each resource type is shown in Figure 25. In the In-state Gas Retirement sensitivity, all ST generation (415 MW) and CC generators with a capacity factor of 10% or less (10,875 MW) were assumed to be retired. We retired generators based on the observed capacity factor solely; location or facility age were not factored. However, given the amount of battery storage deployed in the 2030 portfolios, there is an opportunity for new resources to be sited in close proximity to existing natural gas facilities to help offset transmission and distribution constraints and other local needs, pending a local reliability study.

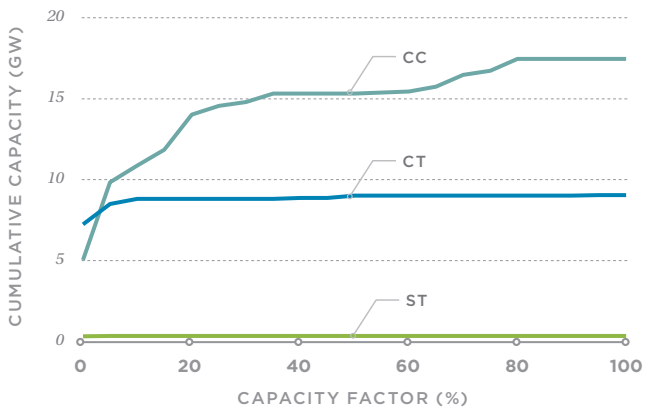


FIGURE 25.

Capacity Factor of Natural Gas Generation by Type

The results of the In-state Gas Retirement sensitivity show that imports from neighboring regions offset a reduction in gas generation. On an annual basis, an almost 1-for-1 exchange is observed between gas generation and economic imports (Figure 26), resulting in a negligible change to the achieved RPS levels. Note that there is a small increase in curtailment due to reduced curtailment with gas retirements, but this change is marginal. This leads to an interesting observation: in both the Base Case and In-state Gas Retirement sensitivity, natural gas and imports are used as the inter-day balancing resources to fill in the gap between renewable generation and energy storage resources, and renewable resources are being fully used to supply load or to charge storage resources. (This result would change if the system is designed specifically with the intention of building resources to displace in-state gas or economic imports, such as renewables and storage being built to exceed 75% and/or if more firm dispatchable resources are available.)

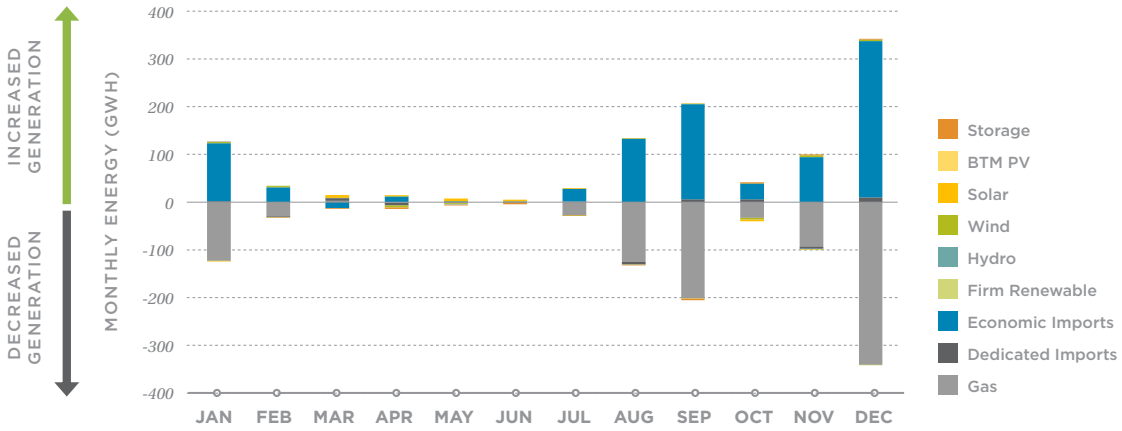


FIGURE 26.

Change in Monthly Generation between the Base Case and Gas Retirement Sensitivity

Although California meets a similar RPS level with the In-state Gas Retirement sensitivity, it does highlight there are hours when the state must import power or may be unable to reliably serve load (i.e., when the gas margin is negative). The Base Case results show over 5000 MW of gas margin are available in the summer. However, after retiring 11 GW of gas generation, there are many hours when the gas margin is negative (Figure 27), indicating that in those hours, California is dependent on imports. While the summer months have the greatest number of hours when imports are required, there are periods in the fall and winter with a negative margin. The negative margin indicates time periods when the system would be reliant on economic imports for reliability (which are largely gas based). However, during negative gas margin periods, the simulations indicate surplus generation across the non-California regions of WECC (i.e., the WECC hourly reserve margin is greater than 0%), and transmission import capability to serve load. This highlights a continued role of the natural gas fleet—or alternative firm resources—to maintain reliability, even if used sparingly.

FIGURE 27.

Natural Gas Margin by Season and Portfolio for the Baseline Assumptions (top) and the In-State Gas Retirement Sensitivity (bottom)

The results of the In-state gas retirement sensitivity show that the riskier periods shift to overnight hours in both the summer and winter, when solar resources are unavailable and energy storage resources are being used heavily (right frame, Figure 28). In the summer months the risk is highest in the early morning before the sun rises and energy storage resources are depleted, while in the late Fall and early

winter the risk is largest in the late evening hours. While system operators will learn to manage, forecast, and adjust operations to cover this shifting risk, it is important that they have a portfolio of resources available that fits the changing need.

BASELINE ASSUMPTIONS

HOUR OF DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
0	7	10	11	15	16	19	11	7	9	11	10	10
1	9	10	11	14	16	19	11	7	8	11	9	10
2	7	10	11	14	16	18	11	7	8	11	9	9
3	9	10	10	15	16	17	11	6	7	11	9	9
4	8	10	10	13	16	16	9	5	7	11	8	10
5	8	10	10	12	16	16	9	5	7	9	9	9
6	9	9	10	12	15	16	9	5	7	10	9	9
7	9	7	9	12	18	23	11	7	13	10	10	9
8	9	11	12	15	18	23	15	12	15	16	13	11
9	14	13	15	16	18	23	17	12	16	16	13	15
10	15	13	15	17	19	23	18	13	17	16	13	13
11	14	13	15	17	18	23	18	14	17	16	13	14
12	14	13	15	17	18	23	17	14	16	16	13	15
13	14	13	16	16	19	23	18	14	17	17	14	15
14	14	13	17	16	19	23	18	13	13	17	13	15
15	13	12	18	16	18	22	14	9	7	14	11	13
16	12	7	15	15	18	19	15	8	9	12	10	8
17	9	6	9	13	17	20	15	8	11	11	9	9
18	10	7	10	11	14	20	14	10	11	11	8	8
19	10	8	11	11	14	19	13	8	10	11	10	9
20	10	8	11	13	15	19	12	8	8	11	9	9
21	9	10	11	12	15	19	11	6	7	10	9	8
22	7	11	11	13	18	18	10	7	10	10	9	8
23	9	10	11	13	17	15	11	7	9	10	8	7

GAS RETIREMENT SENSITIVITY

HOUR OF DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
0	-1	-1	2	7	7	9	1	-3	-1	1	0	0
1	-1	0	3	8	7	8	1	-3	-1	1	0	-1
2	0	0	3	8	8	8	1	-3	-1	1	0	0
3	0	1	4	7	7	7	0	-4	-2	1	-1	1
4	1	1	2	7	7	6	-1	-4	-2	1	-1	0
5	0	0	2	7	7	6	-2	-5	-3	1	-1	0
6	0	-2	2	6	7	6	-2	-5	-2	1	-1	-1
7	1	-1	3	6	8	12	0	-3	4	3	-2	-1
8	0	-1	3	8	10	13	2	-2	5	5	4	2
9	5	4	7	9	10	13	7	1	5	5	4	3
10	7	4	6	9	10	13	6	4	6	5	5	4
11	6	4	7	9	10	13	7	4	7	5	5	5
12	5	5	7	9	10	13	6	5	6	7	5	6
13	6	5	7	9	10	13	6	1	6	6	6	6
14	6	4	7	9	10	13	8	2	3	6	4	6
15	4	3	10	9	11	12	4	-1	-3	4	2	4
16	3	1	7	8	10	8	5	0	0	1	-1	-2
17	0	1	2	4	8	8	6	1	1	2	0	0
18	1	-1	2	4	6	9	4	0	2	2	1	0
19	1	-1	3	5	8	8	2	-1	1	2	0	1
20	1	-1	4	5	6	8	2	-2	-2	2	1	-1
21	1	0	3	5	8	8	0	-2	-2	2	0	-2
22	0	1	3	5	8	8	0	-3	0	1	0	0
23	-1	1	2	5	7	5	0	-2	-1	1	0	-2

FIGURE 28.

Minimum Gas Margin by Month and Hour of Day for the Base Case portfolio, under Baseline assumptions (left) and Gas Retirement Sensitivity (right)

Retiring gas generation under the Diverse Clean Resources portfolio yields similar results, in which the retirement of gas generation is offset by economic imports; however, the Diverse Clean Resources portfolio uses about 20% less economic imports, annually, compared to the Base Case portfolio.

The results of the In-state Gas Retirement sensitivity indicate that the California grid can continue to meet future electricity demand and clean electricity targets with strategic retirement of the in-state natural gas fleet. However, much of the in-state gas fleet will remain an integral part of the grid for reliability, even if they are used sparingly. A future portfolio designed to operate with 80 to 85% clean electricity that incorporates gas retirements (either due to environmental justice objectives or eroding plant economics) will result in a portfolio that is potentially reliant, at times, on non-dedicated, economic imports for reliability. As a result, the timing and scale of retirements should be carefully considered on a plant-by-plant basis until viable clean replacement resources can be integrated. These replacement resources need to provide similar services as the existing gas and economic resources, namely availability when needed and the ability to operate for multiple consecutive days without energy limitations. These replacements may include long-duration storage, biomass/biodiesel, geothermal, hydrogen, carbon capture and sequestration, or other technologies. In the meantime, it may be a prudent policy to retain some existing gas resources during the energy transition as experience in grid operations and reliability is gained.

ENVIRONMENTAL JUSTICE IMPLICATIONS

We conducted an ex-post analysis to account for environmental justice. We compared our In-State Gas Retirement sensitivity with the latest analysis from the California Office of Environmental Health Hazard Assessment ("California EJ assessment"), based on the California Communities Environmental Health Screening Tool (CalEnviroScreen 4.0), which identifies disadvantaged communities and can be used to identify gas generation that should be retired due to environmental justice considerations.[50] We find that the amount of generation capacity retired in our sensitivity (11.5 GW) is similar to the amount of capacity in the California EJ assessment at a 75th percentile CalEnviroScreen score (12.6 GW, Figure 29).

The CalEnviroScreen score is calculated by multiplying the "Pollution burden score" (which represents exposures and environmental effects, such as ozone, lead, traffic) with the "Population characteristic score" (which accounts for sensitive populations and socioeconomic factors, such as asthma, low birth rate, poverty). Higher scores indicate worsening environmental health impacts on local communities.

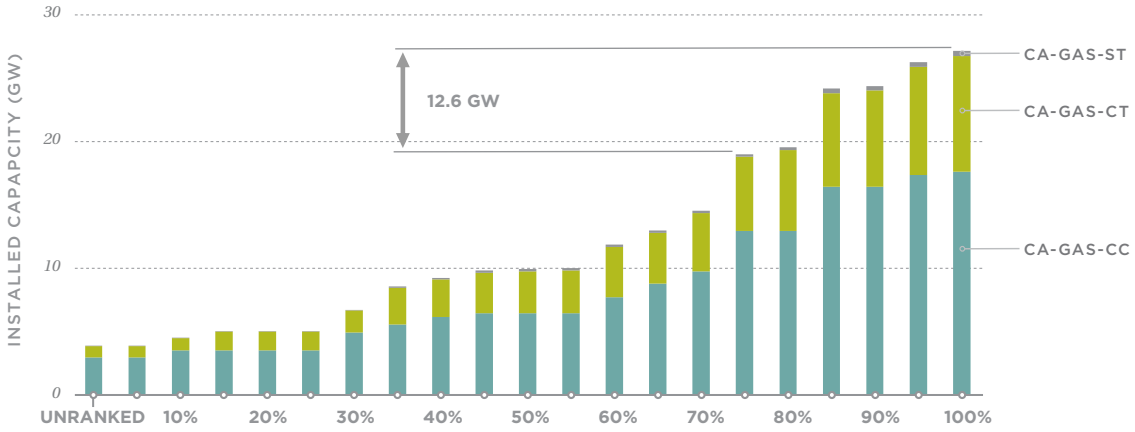


FIGURE 29.

Cumulative Non-CHP Gas Generation Modeled by CalEnviroScreen 4.0 Score

The generation resources retired in this sensitivity are not aligned with the specific generation resources identified by CalEnviroScreen as having the highest impacts on local communities, but the analysis is indicative of how much gas capacity could be retired statewide. Our analysis was performed at the zonal level and does not consider local resource adequacy needs or impacts to the local transmission system; it is possible that system upgrades may be needed to maintain local reliability if certain generators are retired.

50 https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40 / https://oehha.ca.gov/media/downloads/calenviroscreen/report/calenviroscreen40reportf2021.pdf

FINDING 4. **California still has sufficient imports if clean energy replaces coal across the West**

The California system will remain reliable even if all the coal power plants across the west are retired and replaced with a clean energy portfolio, however, economic imports to California will remain an important source of power.

Across our three modeled 85% clean portfolios, 14 GW of coal capacity remain in service in 2030 across the non-California WECC. This quantity aligns with the Western Assessment of Resource Adequacy Report, which projects 16 GW of coal-fired generation remaining in service in 2030 (out of approximately 30 GW in 2020).[51] The report notes that "many coal-fired resources have retired and been replaced by variable generation resources."[52] In our Western Coal Retirement sensitivity, coal across the west is replaced with a mix of wind, solar and battery storage: 14.3 GW of coal is retired across the west, and replaced with 11.1 GW of wind, 7.7 GW of solar, and 3.9 GW of battery energy storage[53]. The result (Table 10) is a non-California, WECC-wide portfolio of 27% renewable (as a percentage of annual load), and 61% renewable or large hydro. With the addition of nuclear, the percentage of zero carbon resources reaches 67%, an increase of 7% relative to the Baseline assumptions.

TABLE 10.

Renewable and Zero Carbon Generation as a Percentage of Load, Non-California WECC Regions, Base Case portfolio, Baseline assumptions vs. WECC Coal Retirement sensitivity

	BASELINE ASSUMPTIONS	WECC COAL RETIREMENTS
Renewable	20%	27%
Renewable and large hydro	54%	61%
Zero Carbon	60%	67%

IMPACT ON CALIFORNIA POWER SUPPLY

Coal-fired power plants have traditionally operated as baseload generation because of their long start-up times and other costs associated with the facilities being idle. However, for all three of our modeled 85% clean portfolios, coal generators are observed to have a capacity factor of roughly 40% on a fleetwide basis. While

51 WECC, The Western Assessment of Resource Adequacy Report, December 18, 2020, https://www.wecc.org/Administrative/Western%20Assessment%20of%20Resource%20Adequacy%20Report%2020201218.pdf

52 Ibid.

53 This was a modeling decision, however, some of the coal capacity could be replaced potentially with other zero-carbon resources, such as nuclear.

some regions show higher capacity factors (60% or greater), others show lower values (20% or lower), presumably because of access to California renewable exports in the non-summer months. The retirement and replacement of these units does not introduce unserved energy in any of the affected regions, indicating that policies that replace coal with clean energy could be effective in reducing emissions and maintain reliable bulk electric service—provided that interregional coordination allows for appropriate transfers of electricity and local transmission constraints are resolved.

Across the portfolios, California often economically imports power from neighboring regions rather than using in-state natural gas resources. However, the Western Coal Retirement sensitivity shows a higher reliance on in-state natural gas especially in the summer, and a decreasing ability to export surplus renewables in the spring. The higher reliance on in-state natural gas is likely due to lower levels of dispatchable generation available for import to California from the rest of the WECC and the increased cost of marginal resources in neighboring regions. Energy from natural gas generation increases in the Western Coal Retirement sensitivities by about 10% on an annual basis across all three portfolios. The decreased ability to export renewable energy creates a small increase in curtailment of renewable resources.

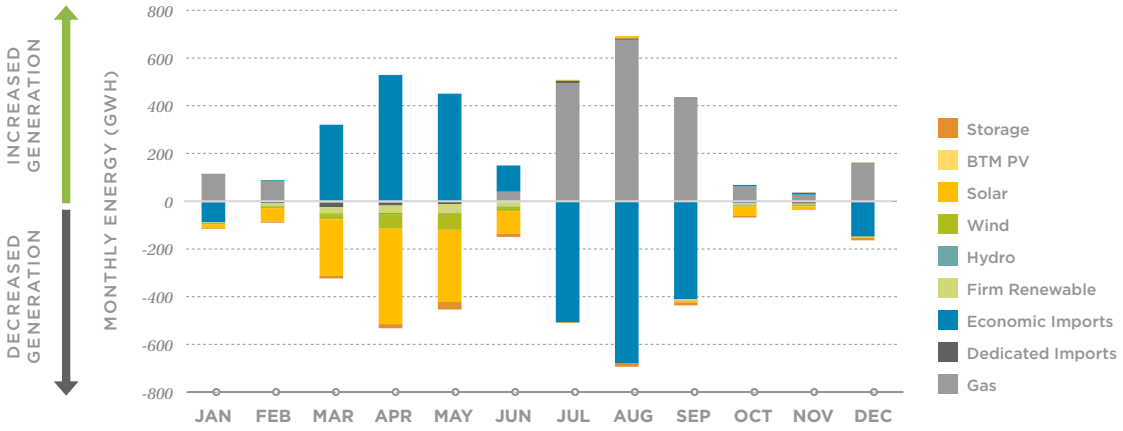


FIGURE 30.

Change in Monthly Generation for the Western Coal Retirement sensitivity compared to Baseline assumptions for the Base Case portfolio. Values are the averages across all eight weather years.

Figure 30 shows the change in monthly generation levels and highlights two periods of interest: In the spring months, California generates an abundance of wind and solar energy and usually does not rely on out-of-state imports; however, with coal retirements, in-state solar and wind resources are curtailed because California is no longer exporting as much energy to its neighboring systems in the middle of the day. A reduction in exports shows up as an increase in net economic imports. In the summer months, generation from in-state gas resources offsets a reduction in imports because there is less surplus capacity available.

IMPACTS OUTSIDE OF CALIFORNIA

Outside of California, Figure 31 shows how resource utilization changes in the southwestern states as a result of retiring over 4 GW of coal generation. In these three summer peak days, we see the importance of flexibility from energy storage and imports from neighboring regions, in which a large amount of imported energy is generated by California solar resources. In the Base Case portfolio under baseline conditions (upper frame) coal generation was greatly relied on during these days with a minimum of 3 GW in service; when coal is unavailable (lower frame), the model replaces it with natural gas and imports during the overnight hours, and with large offsets from solar and storage in the late morning and early evening.

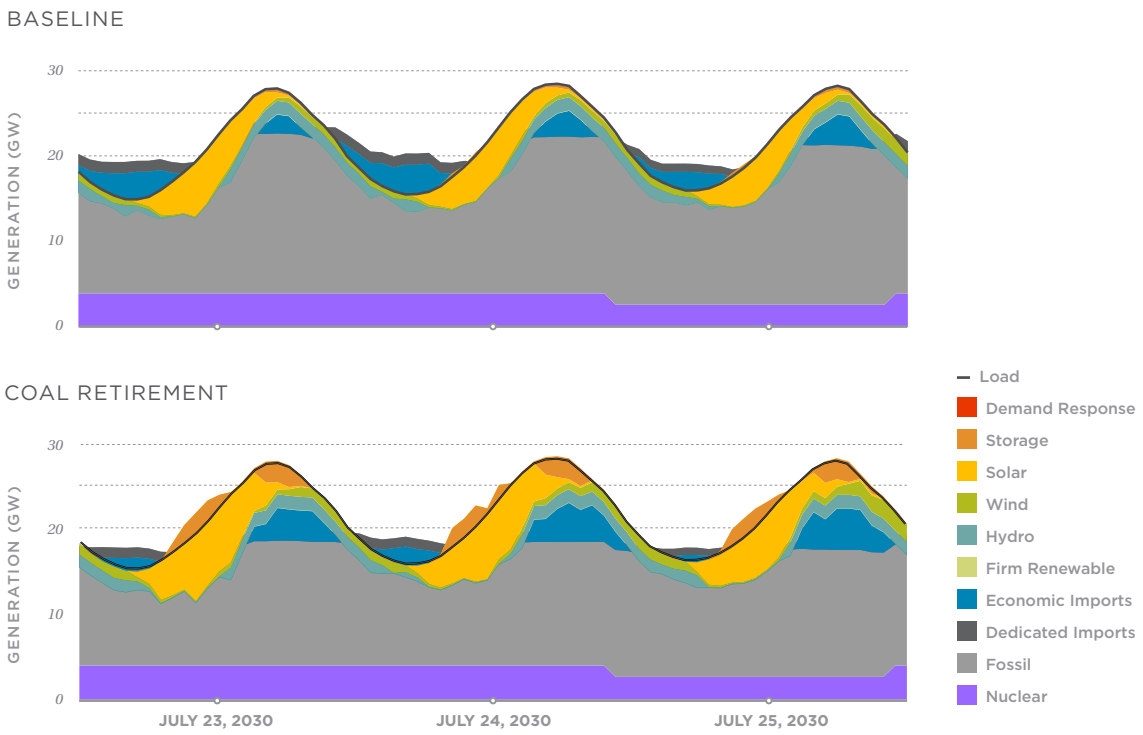


FIGURE 31.

Change in the Southwest Region Resource Utilization between the Baseline (top frame) and Western Coal Retirement Sensitivities (lower frame) for the Base Case portfolio; 2007 weather year

We added a relatively small amount of wind resource to the Southwest region, which provides approximately 200 MW of additional capacity, on average, in these days. The dispatch of nuclear units remains unchanged and hydro generation adjusts to fill the gaps. The Western Coal Retirement sensitivity suggests that substantive changes to the WECC resource portfolio can occur if interregional support is available during times of need.

FINDING 5. **The system is reliable against varied weather conditions**

The California system can meet load when assessed against extreme weather conditions as represented in multiple weather years. This assessment includes multi-day low wind events and extreme heat like those which occurred during the August 2020 rolling outages.

MULTI-DAY LOW WIND AND SOLAR EVENTS

An objective of this study was to determine if a clean power system can be resilient against anomalous weather events, including multi-day low wind and solar periods, extreme heat, and drought. To assess this risk, we identified multi-day periods of low wind and solar defined as three consecutive days below 30% of daily load energy. Figure 32 shows the daily energy from variable renewable energy sources for each day (gray dots) and a rolling three day average (blue dots) across the eight weather years; it highlights multi-day periods where available wind and solar resources in California are well below normal, which could lead to full discharge of battery resources and significantly increased reliance on in-state natural gas resources or economic imports. Daily energy from variable renewables varies greatly by season, peaking to approximately 70% of daily load during the spring months, is in the 40-60% range for most of the summer and fall months, and is lowest during the winter months.

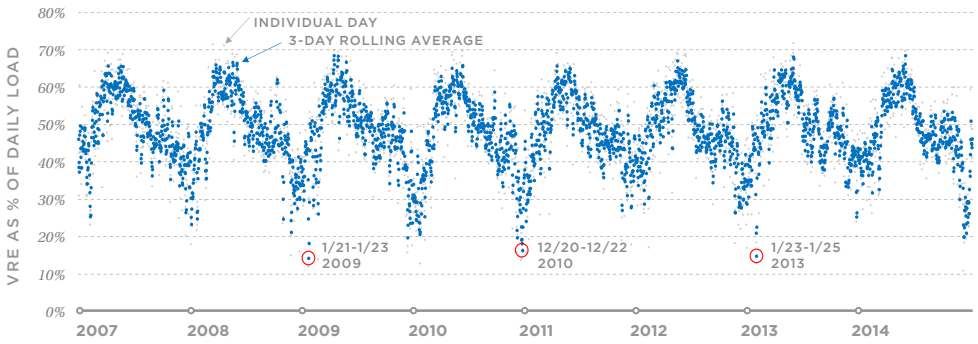


FIGURE 32.

Multi-day Low Wind and Solar Events in California (based on the Base Case portfolio and baseline operating assumptions); similar trends were observed for the Diverse Clean Resources and High Electrification portfolios.

All of the multi-day low wind and solar events for our modeled 85% clean system occur in the weeks surrounding the winter solstice. Three of these time periods are marked on the figure and we confirmed these correspond to actual weather events in California. For example, the period highlighted in 2010 represented a heavy

precipitation event in California and Nevada. Although the data set in this study (from the NSRDB and the WIND Toolkit), is based on weather models, the modeled data capture an extreme weather event in December. As the National Oceanic and Atmospheric Administration (NOAA) noted:

> *"In the span of one week, a series of mid-December storms in rapid succession rather quickly discredited climate predictions of a drier-than-average La Niña winter in southern California, southern Nevada and much of the Southwest, producing in some cases record-setting rain and snowfall. The first rains and snow hit California December 16th and subsequent periods of heavy rains continued almost unabated for a week with heavy snowfall in the Sierra Nevada Mountains."*[54]

Our modeled 85% clean power system is able to adequately serve load during these multi-day low solar and wind conditions. There are two primary reasons for this. The first reason is that there is a surplus of available in-state natural gas generation because demand in the winter is significantly lower than in the summer. In general, California winter load is approximately 25 GW lower (nearly 40%) than in summer peak periods. Even with the additional levels of electrification in the High Electrification portfolio, which results in a larger growth in winter peak load than summer peak load, the overall peak demand for winter in the High Electrification analysis remains lower than summer peak load of the Base Case portfolio (Figure 33).

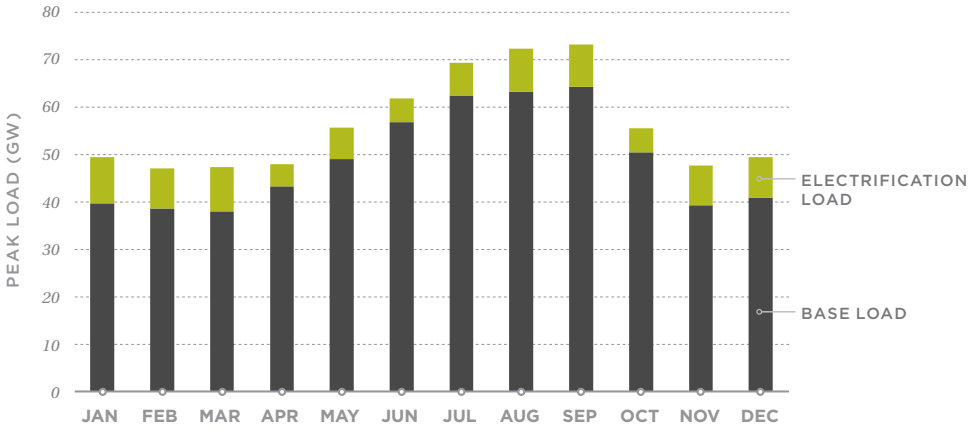


FIGURE 33.

Monthly Peak Load Comparing the High Electrification portfolio demand with the Base Case portfolio demand

The second reason the modeled system can serve load through the low wind and solar events is because California can import energy from neighboring regions.

54 National Oceanic and Atmospheric Administration, Heavy Precipitation Event, California and Nevada December 16 - 23, 2010, https://www.cnrfc.noaa.gov/storm_summaries/dec2010storms.php

Figure 34 shows increased economic imports and in-state gas dispatch during the low wind and solar event as well as the decreased margin in the lower chart (highlighted with the dotted box) and shows that even in the absence of economic imports there are enough in-state gas resources to serve load.

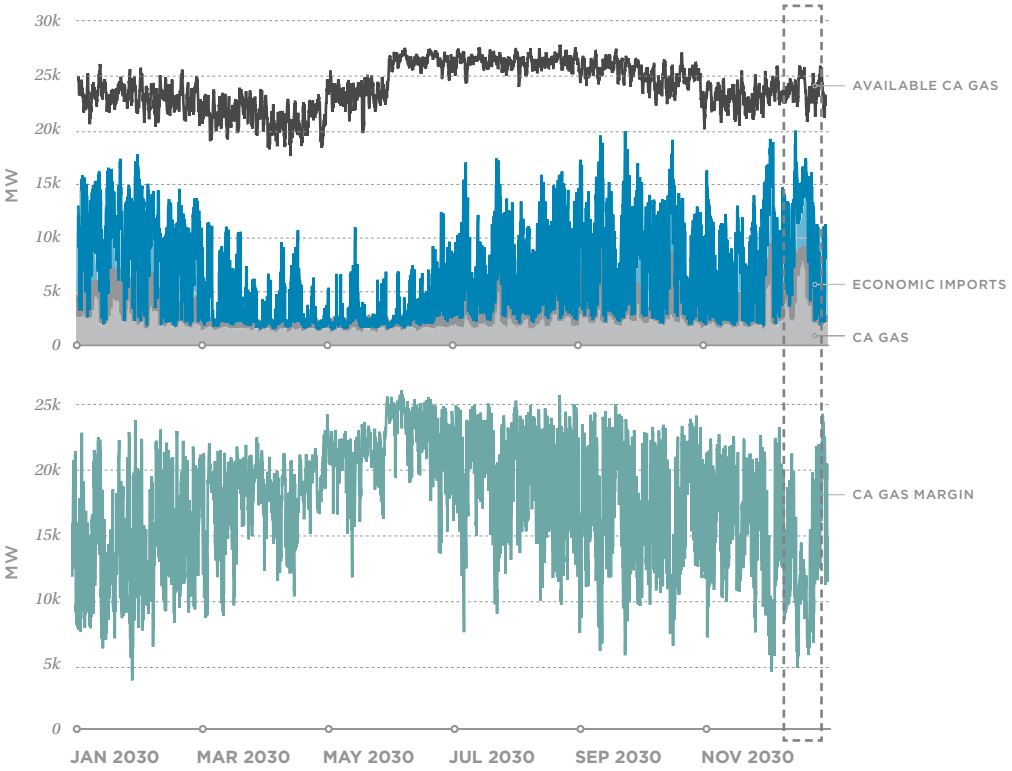


FIGURE 34.

In-state Gas Dispatch and Economic Imports, Weather Year 2010; dotted box represents a low wind and solar event

ATMOSPHERIC DEEP DIVE ON THE MULTI-DAY LOW RENEWABLE EVENTS

We conducted an atmospheric science analysis to more deeply understand the physics of the three multi-day low wind and solar events.[55] The primary driver for this analysis is that we anticipate these types of multi-day low renewable events to be more common in the future. As such, we deemed a deeper analysis leveraging meteorological expertise, which is not typically leveraged in power system analysis, to be important. This deeper analysis reveals three key trends:

First, the three events are not particularly "extreme" with respect to the type of weather that makes the news, although the December 2010 event is unusual in

55 This deeper analysis was conducted by Dr. Justin Sharp, Sharply Focused. Dr. Sharp is a PhD atmospheric scientist with specialized expertise in weather modeling and renewable data. The full analysis conducted is published in a separate report, "Meteorological deep dive of low renewable energy periods in accelerated 2030 california clean electricity portfolios"

the amount of precipitation it produced over a seven-day period in Southern California. However, they illustrate that relatively long periods (on the order 5-10 days) of Dunkelflaute[56] conditions are possible across a broad swath of the WECC. While the details varied among the events, there are some commonalities. In each case a high amplitude upper-level ridge is established with the axis somewhere between the Great Basin and the Rocky Mountains. This ridge blocks the progress of incoming weather systems and weakens them. It also promotes surface offshore flow and inverted conditions (i.e., temperature increases with height and the surface layer is very stable so that higher momentum air is unable to mix downwards) that are not conducive to good wind generation, while at the same time pushing moisture into the region to create cloudy conditions. Fog is a factor where a strong inversion forms, especially in the northern part of WECC. The conditions in January 2009 and January 2013 are quite similar and represent a pattern that is common in the western US. The December 2010 event still exhibits the ridge, but the details are a bit different. Overall, these types of events are not exceptionally rare and could occur at a frequency of 3 to 5 times per decade on average.

While our modeled power system can serve load during multi-day renewable events (primarily due to gas availability), the trends we observed highlight that both California and the rest of the West need a very thoughtful approach towards renewable buildout as they decarbonize the regional power system. "Peaking" wind resources, which refers to wind resources that are low on an annual average, but high when other wind resources are low, could be considered by power system planners.

Second, although the modeled clean power system is able to serve load during these events, the renewable resources we selected for this study exhibit somewhat limited diversity. In these three multi-day low renewable events, the solar fleet across the WECC exhibits low capacity factors because it is cloudy across the region. However, there is some diversity in the wind fleet modeled here with desert southwest and Rocky Mountain wind providing more energy than is typical in winter and making up some of the region-wide shortfall. A deeper investigation using NREL wind resource maps reveals that other portions of the Desert Southwest exhibit strong wind resource during these events but our model did not include them in the renewable buildout. While our modeled power system can serve load during multi-day renewable events (primarily due to gas availability), the trends we observed highlight that both California and the rest of the West need a very thoughtful approach towards renewable buildout as they decarbonize the regional power system. "Peaking" wind resources, which refers to wind resources that are low on an annual average, but high when other wind resources are low, could be considered by power system planners. These may include areas of the desert southwest, Baja, and on the west side of the Cascades and Sierra Nevada. This kind of locational information must be included in planning models or considered exogenous to planning models if they cannot be included. For example,

56 The term Dunkelflaute was coined in the European renewable energy sector to describe periods where little renewable energy is generated. Its literal translation from German is "dark doldrums" or "dark wind lull".

a recent NREL study on extreme weather events[57], which used REEDs for capacity expansion, did identify some peaking wind resources in the modeled build out.

Third, there are known deficiencies in the WIND Toolkit data set—there is a consistent bias in the modeled data that over-predicts the wind resource for the Bonneville Power Administration (BPA) region and may over-predict the resource in other areas too. This bias is much larger in the winter months and occurred during these low wind and solar events. Our future power system included about 9500 MW of wind capacity in the BPA region. Over the days from January 20 to January 26, 2009 this bias amounts to roughly 130 GWh and on an hourly basis, and the bias is as high as 4000 MW (which means that this bias could result in a gas margin that is 4000 MW lower). The reason for the bias is the handling of the stable boundary layer by the Numerical Weather Prediction (NWP) model used to create the wind resource dataset in the WIND Toolkit[58] and is exacerbated by the fact that the pattern present during these events produces a shallow and very stable surface layer in the Pacific Northwest, which the NWP models typically mix out prematurely, translating to higher near surface wind speeds being modeled than observed in reality. In layperson terms, in these low renewable day events, a pool of cool air forms on the east side of the Cascade mountains and other mountain regions is very stable and stagnant, and results in low wind speeds. As the warm air comes in from the west, it glides over the cold layer and is unable to mix vertically due to density differences. This imperfection is well known among the atmospheric science modeling community and improvements have been made to the source NWP model since the WIND Toolkit dataset was produced. Although the current WIND Toolkit dataset contains this problem, data can now be produced using updated codes that improve upon, though don't completely remove, the issue.

This issue should be carefully tracked in future analysis and more accurate datasets should be incorporated, or minimally, the impact of the bias should be factored. In the case of our modeled 85% clean system, even if the entire BPA wind resource drops to zero, as during the January 2009 event, there are sufficient gas resources remaining across the region to make up for this deficit.

MULTI-YEAR LOAD ANALYSIS AND AUGUST 2020 EVENT

California recently experienced extreme regional heatwaves. This occurred during the August 14-15 2020 resource adequacy events, in which Southern California temperatures exceeded 120 degrees.[59] Regional heat waves also occurred during the summer of 2021, in which record-breaking temperatures affected much of the Western United States and Canada. These kinds of heat waves can significantly increase electricity loads across a broad region and stress power system operations.

57 Novacheck, Joshua, Sharp, Justin, Schwarz, Marty, Donohoo-Vallett, Paul, Tzavelis, Zach, Buster, Grant, and Rossol, Michael. The Evolving Role of Extreme Weather Events in the U.S. Power System with High Levels of Variable Renewable Energy. United States: N. p., 2021. Web. doi:10.2172/1837959.

58 The Weather Research and Forecasting (WRF) model is the numerical weather prediction (NWP) model that is used to generate the Wind Toolkit data.

59 California Independent System Operator, Final Root Cause Analysis, Mid-August 2020 Extreme Heat Wave, January 13, 2021. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

To assess the impacts of weather variability on power system operations, we extended our analysis—which otherwise relied on a fixed demand profile (i.e., mid-mid IEPR demand profile)—to incorporate multiple demand profiles that reflected historical weather conditions from 2000 to 2019 over the summer months (May through October).

Overall, we observe that there are no periods of unserved energy across the 20 years evaluated for each portfolio. However, the load is significantly above average during Week 35 using 2017 weather data. This week started on August 28 and ended on Sept 3; during these 7 days the peak load in August was observed to be approximately 7% higher than average. The actual load from the August 2020 event was also 7% higher than the expected load, so the 2017 event serves as a reasonable proxy.[60] On September 3rd, the modeled load is 25% greater than average and is also the highest load period in the twenty-year sample. The August and September peak loads across the 20 weather years are shown in Figure 35.

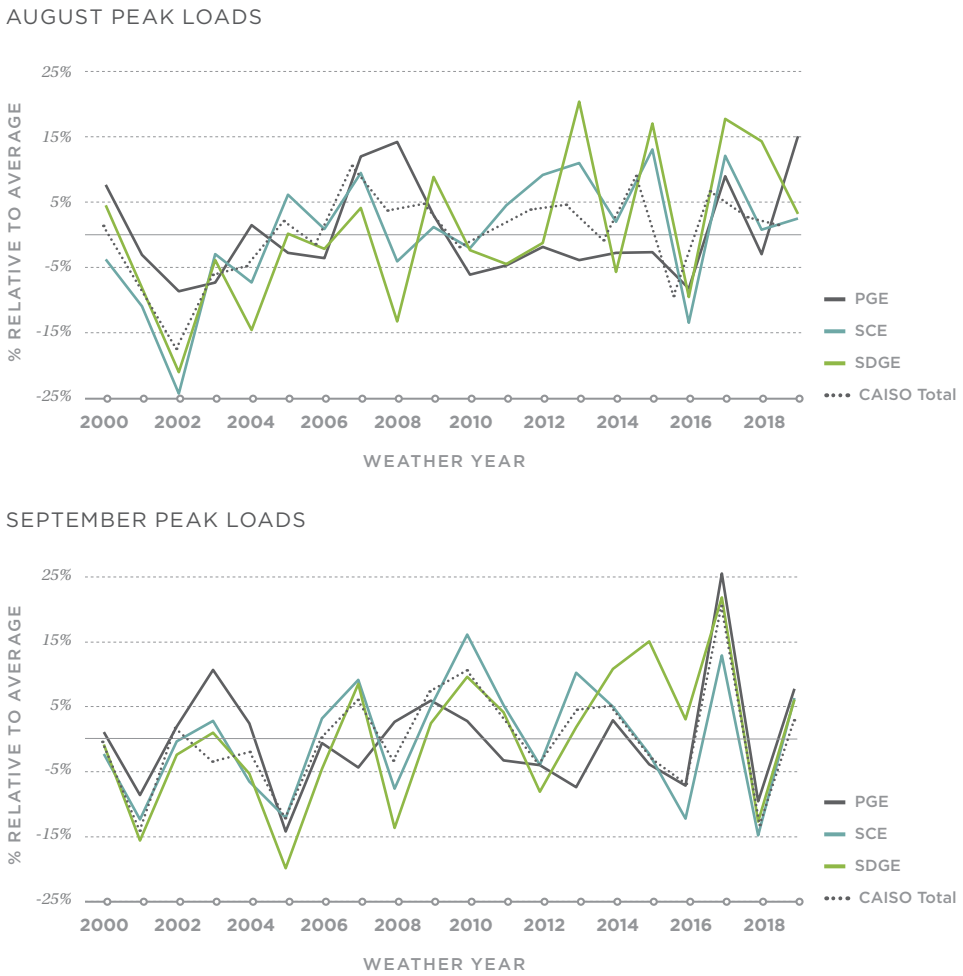


FIGURE 35.

August and September Peak Loads by Weather Year Relative to Average

60 Ibid.

Because our dataset from the CEC did not include future load projections representing 2020 weather data, we could not perform a direct production cost simulation analysis of the 2030 power system against the August 2020 weather data. However, we believe the 2017-weather year load is a reasonable proxy for understanding the impacts of August 2020 conditions on a future clean power system. We compared the 2030 August demand data and modeling results for the CAISO footprint (based on the 2017 weather year) with the actual August 2020 CAISO hourly resource mix and load shed events. We refer to this as the "Proxy August 2020 event in 2030". The Proxy August 2020 event in 2030 exhibits a CAISO peak evening net-demand of 57,163 MW, which is 22% higher than the actual August 2020 event where CAISO load reached 46,712 MW. This represents a more than 10 GW increase in peak demand that was able to be served, despite a reduction in firm capacity of approximately 5,000 MW (due to the retirement of Diablo Canyon Nuclear Plant and once-through cooling natural gas plants).

Figure 36 compares data from the actual August 2020 event with the Proxy August 2020 event in 2030 results. The top left frame shows the electricity supply during August 14, 2020 and the load shedding that occurred during the peak evening hours. During the load shedding period, the imports into CAISO averaged approximately 7,400 MW and CAISO natural gas generation was around 25,000 MW. The central and right frames of Figure 36 show the results of the Proxy August 2020 event in 2030. The central-upper frame shows the generation mix estimated by the model assuming no import limitations. In this case, imports were found to be available and were much higher than the August 2020 event, suppressing the need for in-state gas generation. There is an increased availability of evening renewable energy, compared to the actual August event (upper-left frame), due to the increased wind and energy storage in the 2030 Base Case portfolio.

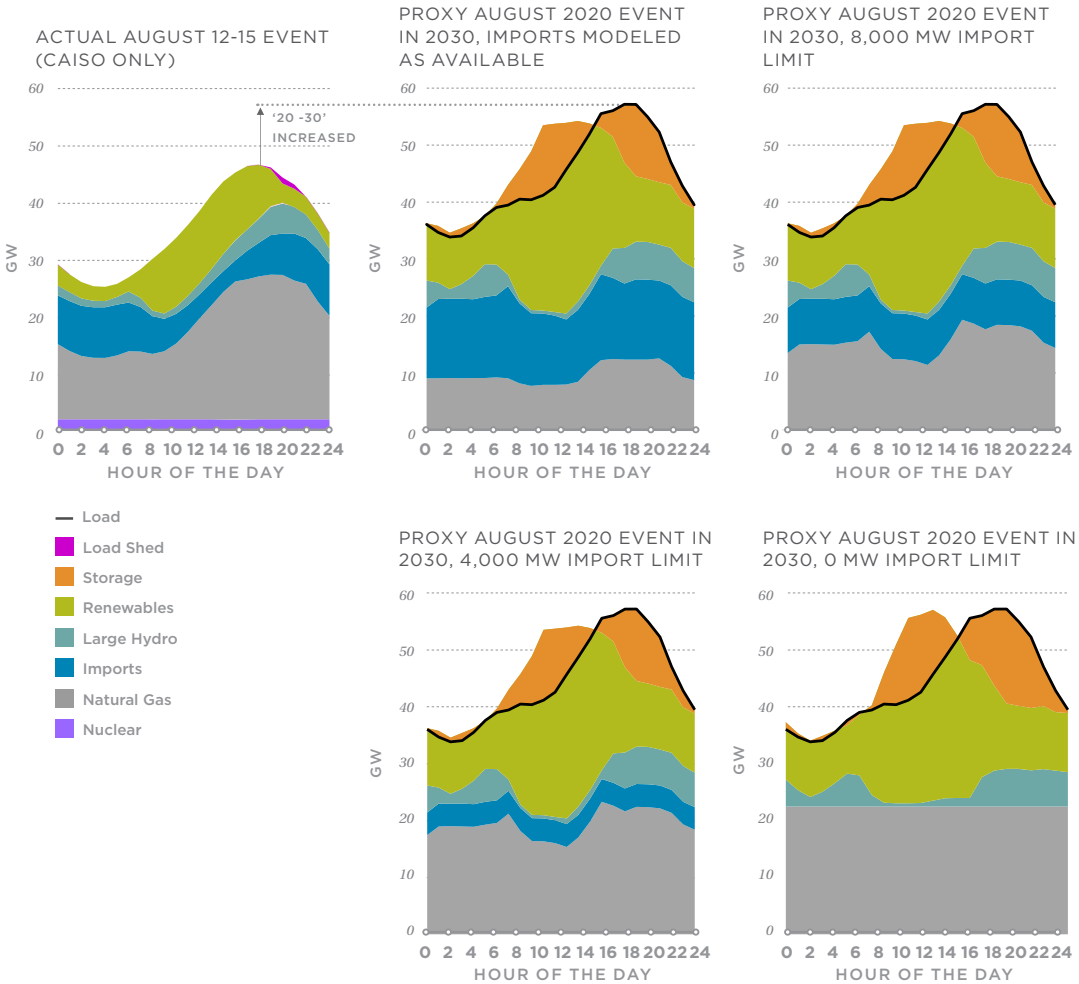


FIGURE 36.

Actual August 2020 Load Event (left frame) versus Proxy August 2020 Event for 2030 (central and right frames)

Given that imports may be limited during a regional heatwave event, we conducted production cost modeling at three different import levels: with a 8,000 MW, 4,000 MW, and 0 MW import limit (applied to economic and non-renewable dedicated imports). At the 0 MW import limit (lower-right frame) we find that in-state natural gas resources are dispatched up to the maximum 22,500 MW available in the CAISO footprint. This value is a conservative estimate of available gas capacity that accounts for potential outages. Even with an increased peak demand of 10 GW and the retirement of some gas and nuclear resources, the system is able to serve load during this period across various levels of import availability.

In this example, battery energy storage takes on an integral role in replacing the economic imports, which requires that the state of charge is managed carefully. We note that in the case with zero imports, the energy storage requires a non-zero state of charge coming into the day to have enough energy to cover the battery dispatch during the day, given the limited ability to charge during the day. Energy storage will need to be managed such that the system is resource adequate in evening periods. Alternatively, if the energy storage is fully depleted and carries no energy from the previous day (due to multi-day peak load or low renewable energy events) then there may be a need for mid-day imports so that the storage can charge from renewable generation.

Our analysis suggests that under multiple conditions, including various import assumptions, a future power system is capable of meeting demand similar to what was observed in the August 2020 event. While the modeled 85% clean system is shown to be robust against heat wave events, it is sensitive to import limitations from neighbors; and without imports, the power system is fully dependent on the fleet of natural gas resources to meet load during extreme events, unless other resources are built to provide the services of the natural gas fleet.

FINDING 6. **The system is reliable against simultaneous stressors**

The system reliably serves load when tested against multiple stressors occurring simultaneously (retired in-state gas, retired west-wide coal, import constraints, low hydro availability, extreme weather).

The Combined Stressor sensitivity evaluates the performance of each portfolio when tested against a combination of different system stressors:

- In-state natural gas retirements
- Limited imports of 13 GW
- Hydro consistent with drought conditions (bottom 10th percentile of monthly available energy)
- Coal retirements across the WECC
- Summer load consistent with the range of 20 different weather years

RELIABILITY METRIC OUTPUTS

The Combined Stressor sensitivity shows that our modeled 85% clean systems are robust across most system conditions. Of the 3,680 days evaluated across the 20-weather year summer period sample, only 5 days experienced a capacity shortfall, spread across 24 hours total (or approximately 4.8 hours per loss of load day). While not enough stochastic samples were evaluated to calculate robust resource adequacy metrics, this represents a loss of load expectation (LOLE) of 0.25 days per year or 1.2 hours per year loss of load hours (LOLH). The five loss of load events that occurred lasted for 1, 3, 5, 6 and 7 hours respectively (average of 4.4 hours per event). Figure 37 shows the loss of load hours by month and hour of day, indicating that September evening hours have the highest likelihood of capacity shortfalls. These shortfall events are relatively short and could be addressed with load flexibility and shed-based demand response if used strategically during extreme events.

These metrics should be interpreted with the caveat that in order to fully quantify the resource adequacy metrics, the 20-weather year sample would need to be run across many hundreds of randomly selected outage draws on the thermal fleet.

	HOUR OF DAY																								
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	TOTAL
MAY																									0
JUNE																									0
JULY																		1	1	1					3
AUGUST																1	1	1	1	1	1				6
SEPTEMBER												1			1	1	2	3	3	2	2				15
OCTOBER																									0
TOTAL												1			1	2	3	5	5	4	3				24

FIGURE 37.

Loss of Load Hours by Month and Hour of Day

The average event constituted a 2.5 GW shortfall and the maximum event had a shortfall of approximately 8 GW. This indicates that the system would have likely been robust for all three portfolios, had the 11.3 GW of natural gas resources not been retired. As shown in Figure 38, the natural gas margin is reduced considerably in the gas retirement sensitivity, and is often negative. This indicates that if our assumed levels of natural gas retirements occur, then the system would become reliant, at times, on neighboring systems for reliability.

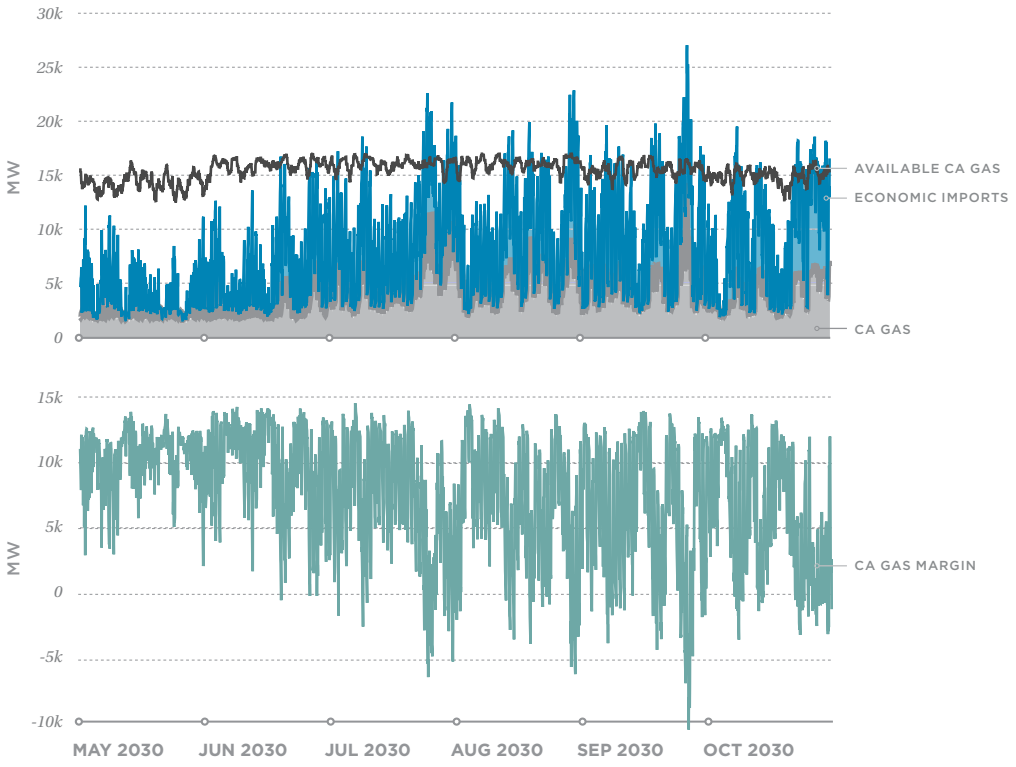


FIGURE 38.

Natural Gas Margin in Combined Stressor Sensitivity

Another way to view the level of system stress during the Combined Stressor sensitivity is the WECC-wide hourly reserve margin plot (Figure 39), which compares the California economic imports versus WECC hourly reserve margins during the same time periods. The upper left quadrant of Figure 39 shows that there are notable imports to California during time periods of relatively tighter supplies across the WECC. The two extreme peak day periods are highlighted in the red and black dots.

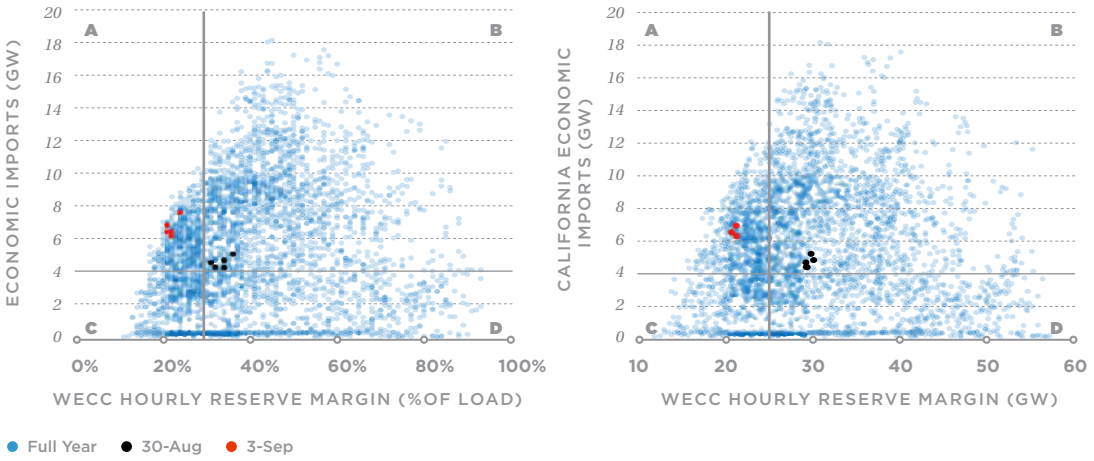


FIGURE 39.

Hourly California Imports versus WECC Hourly Reserve Margin in the Base Case Portfolio, Multiple Stressors Sensitivity

EXTREME PEAK DAY RESULTS

Figure 40 shows the dispatch of our modeled 85% clean power system using weather data for August 30th and September 3rd of 2017. The August 30th event, which was previously discussed, is shown here with the full California footprint (including the publicly owned utilities) and with the multiple stressors occurring simultaneously. Here, demand response and load flexibility is leveraged in the evening hours to serve load; on September 3 load shedding occurs in the late afternoon and early evening hours due to the lower levels of renewable energy and higher load.

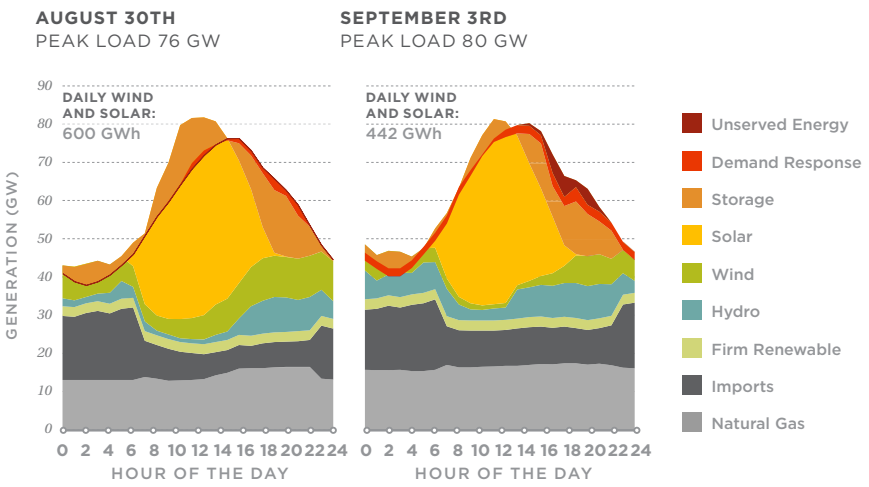


FIGURE 40.

Sampled Extreme Peak Day with Multiple System Stressors and Unserved Energy

This event is notable for a few reasons. First, the September 3 2017 weather event represents the highest peak load in the 20-year dataset, and is 25% higher than average peak loads occurring in September. This is an extreme peak load event, combined with relatively low renewable availability, natural gas retirements, and an import limit. Second, the battery storage systems are energy limited due to relatively low solar production. However, if imports are not artificially capped during mid-day periods, when much of the WECC has surplus solar, then batteries could be charged and would have available energy during the evening net peak period.

Overall, the Combined Stressor sensitivity analysis indicates that our modeled 85% clean system is robust most of the time. Only 5 days out of 3,680 days evaluated show capacity shortfalls and each one of these could have been avoided if the mid-day import limit was not artificially constrained to 13,100 MW (given the surplus amount of solar across the West) or if the total natural gas retirements had been lower. This sensitivity illustrates the importance of the interdependency between in-state natural gas resources and the availability of imports from the rest of the region as a critical factor for California resource adequacy. It also suggests a need for better multi-hour and multi-day coordination of dispatch across the WECC, which would also support addressing multi-day low renewable events. This is true for both planning and operations, both of which will require increased interregional coordination.

FINDING 7. **Demand flexibility is a tool for reliability and can lower storage needs**

Load flexibility/load shifting can offset some battery needs and provide a hedge against uncertainty in predicting resource availability and high demand events. This hedge value will be important in the winter as newly electrified loads are expected to contribute to winter reliability risk.

Our baseline operating assumptions assume that the traditional "shed" form of demand response is available to the system, rather than load or demand flexibility which results in load "shifting". Although storage can deliver load shifting, demand side flexibility can be an important operational tool. The purpose of the Demand Flexibility sensitivity was to explore the operational benefits of this type of demand response.

We assessed demand flexibility using two broad sets of assumptions: for the Base Case and Diverse Clean Resource Portfolios, we leveraged data from the Phase 3 California Demand Response Potential Study by LBNL (LBNL Study).[61] For the High Electrification portfolio, we used the LBNL data but conducted additional simulations where up to 20% of the newly electrified building and EV loads were assumed to be flexible.

SUMMER SHIFTING

Figure 41 shows the amount of embedded HVAC load for a typical hour in August and after being impacted with load shifting. The dashed lines represent the bounds of how much the HVAC load can be shifted—up to 250 MW in the morning hours and over 900 MW in the afternoon. The solid yellow line represents the load pattern after the HVAC load is shifted by precooling the space during the middle part of the day. The modified load shape is increased in the middle of the day, and decreased in the late afternoon and early evening, relative to the original load shape.

61 LBNL, Phase 3 of the California Demand Response Potential Study, https://buildings.lbl.gov/download-phase-3-dr-potential-study

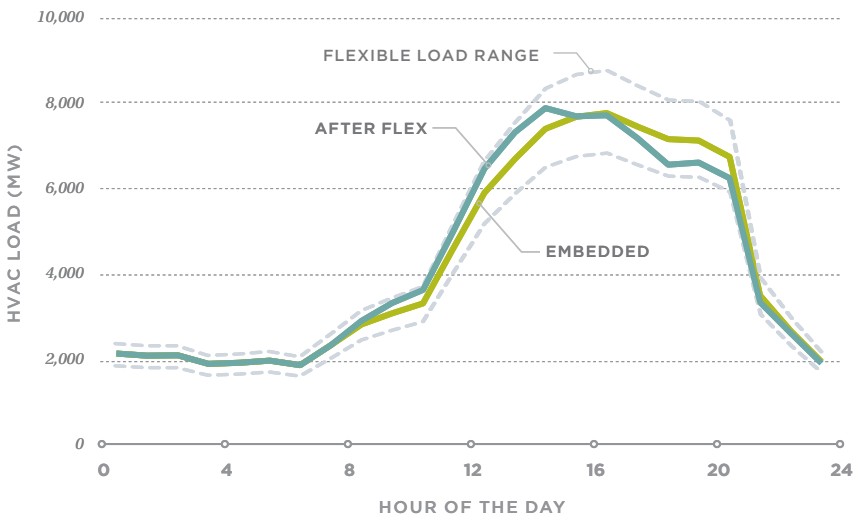


FIGURE 41.

Available Flexible HVAC Load in August

On aggregate, considering all four flexible end uses, according to the LBNL study, the overall California load has the potential to be increased by 1500 MW during the late morning hours and reduced by up to 1500 MW during the early evening hours. Figure 42 shows the resulting system-level shift from load flexibility, considering all four flexible end uses, for the Base Case portfolio in August. In this example, the application of flexible HVAC increases the load from hour 8 to 15, due to pre-cooling during high solar hours, and decreases it from hours 16 to 20 when net load peak is higher. Load flexibility represents the opportunity, on average, to reduce the net load ramp by almost 3000 MW, which may reduce operational challenges.

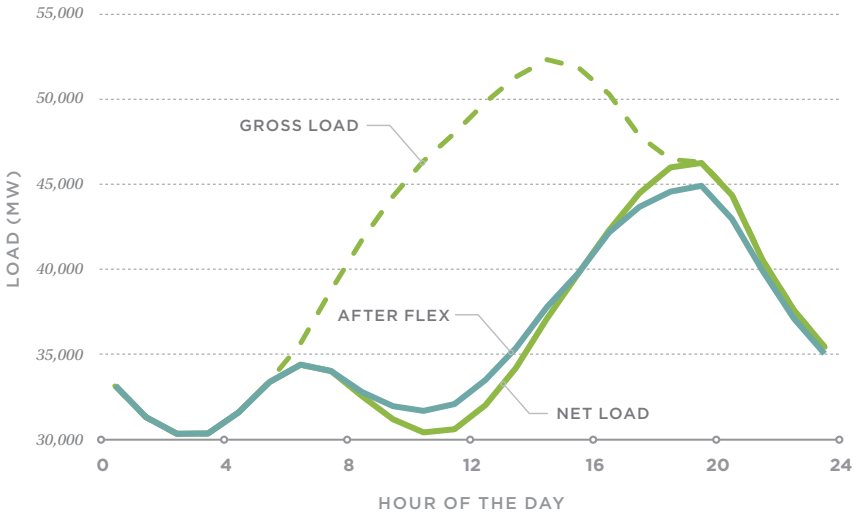


FIGURE 42.

Average Hourly Changes to the System Net Load from Flexible Resources in August

WINTER SHIFTING

Building electrification will include the adoption of heating systems such as heat pumps, which will increase winter load, expanding the periods of concern for grid operators to both summer and winter. Previously, Figure 33 showed how electrification may alter the monthly peak load; namely, while the California system remains as a summer-peaking system, the largest load increase due to electrification is in the winter months. The Demand Flexibility sensitivity results for December (Figure 43) show that load shifting dampens the average hourly load increases, which range from 4 to 9 GW.

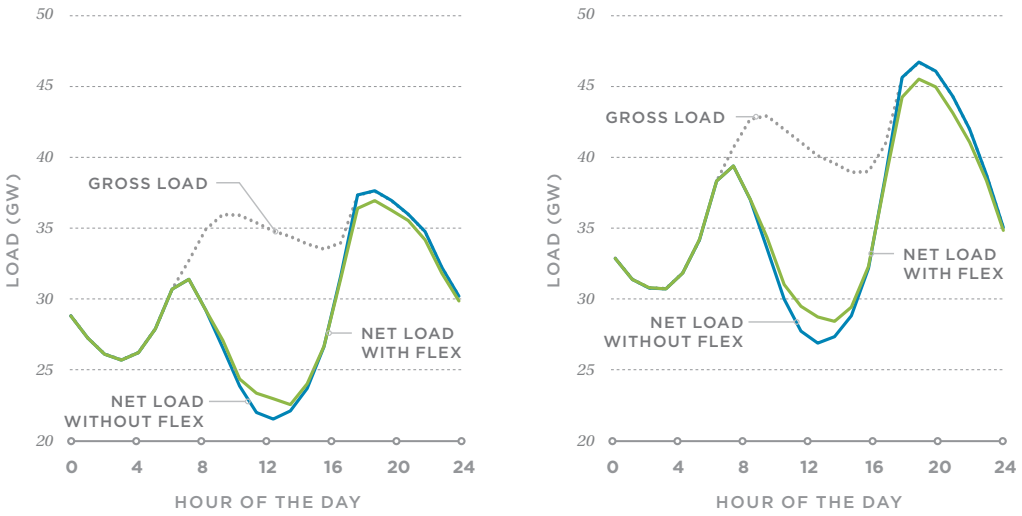


FIGURE 43.

Average Load by Hour in December for Base Case (left frame) and High Electrification Load (right frame) with and without demand flexibility (net load is gross load minus BTM solar)

OVERALL RESULT

Our simulations show that the availability of demand flexibility has a relatively small effect on the overall system dispatch, due in large part to the high levels of storage capacity assumed in the 2030 power system. For perspective, the Base Case portfolio contained utility-scale storage resources with a peak shift capability of over 25,000 MW and a daily energy shift capability of 75,000 MWh, significantly larger than the assumed load flexibility potential of approximately 3,000 MW and 6,000 MWh. This explains why the Demand Flexibility sensitivity results in minimal operational changes when assessed across the three portfolios. However, load flexibility can be viewed as a partial substitute, and a hedge to large-scale battery storage deployment if the technology cannot be deployed as quickly as possible, or to introduce resource diversity. An alternative pathway that we did not study is a portfolio with lower storage and more load flexibility. As a reminder, the scope of our study was restricted to bulk system analysis, and we did not analyze distribution system benefits from load flexibility.

FINDING 8. **Modeling and planning tools need to evolve**

Modeling tools and planning processes need to evolve to better capture the effects of geographically diverse resources, uncertainties about technology costs, and the impact of inter-regional coordination.

BEYOND CAPACITY EXPANSION MODELING

Traditionally, much of California's analysis conducted for the state's Integrated Resource Planning uses capacity expansion modeling (i.e., RESOLVE) to identify least-cost portfolios to meet future demand. However, capacity expansion modeling develops resource mixes based on a small sample of operational days, rather than using chronological analysis across a full year; and they often use a single weather year representation with simplified renewable representation across broad geographies. Due to computational limitations, they are unable to capture the effects of uncertainty of future technology costs, an input that drives the model results.

An iterative approach between capacity expansion and resource adequacy—partially implemented by the California Public Utilities Commission use of RESOLVE and SERVM—should become a new standard for resource planning.

As renewable penetration increases, the combined effects of using sample days, a single weather year, and neglecting the effects of technology cost uncertainty and renewable granularity will make capacity expansion model results less meaningful. We advocate that while capacity expansion modeling is useful, it should be used for screening purposes in combination with other analytical tools and in a more holistic analytical process.

An iterative approach between capacity expansion and resource adequacy—partially implemented by the California Public Utilities Commission use of RESOLVE and SERVM—should become a new standard for resource planning. This iterative process could implement the following sequence:

1. Probabilistic resource adequacy modeling (i.e., using SERVM in the CPUC's IRP process, or equivalent) can be conducted to develop initial estimates for required planning reserve margins and effective load carrying capabilities (ELCC) for resource types. (The ELCC exercise here is for the purpose of developing inputs to capacity expansion modeling, since most models don't endogenously calculate capacity contributions).
2. Information from the first can be used as an input into capacity expansion planning tools (i.e., using RESOLVE in the CPUC's IRP process or equivalent). This step would identify a potential least cost plan to meet the state's RPS targets.
3. After reviewing capacity expansion results of step two, exogenous

decisions can be made to the results to develop alternative portfolios that specifically address policy goals, such as clean energy resource diversity or specific technology policies. The alternative portfolios are included in the modeling framework, in addition to, a base case capacity expansion plan.

4. The resulting portfolios from the third step can be evaluated for system reliability in two ways through "back-checking":
   a. Probabilistic resource adequacy modeling, using a similar methodology from Step 1, but with the specific portfolios identified by the capacity expansion model. This will test whether the planning reserve margin or ELCC capacity contributions estimated in Step 1 are appropriate and result in an adequate portfolio.
   b. Stress testing of specific challenges, possible events, for a suite of portfolios identified in the preceding steps, that could be a challenge for the future California portfolio. The analysis in this study follows this approach.
5. Once the back-end checks are completed, analysis to review the size, frequency, duration, and timing of potential shortfall events or risk periods can be used to implement proper mitigations, change the proposed portfolios, or adjust the inputs developed in Step 1.

ELEMENTS OF AN EVOLVED MODELING FRAMEWORK

We describe the elements of an evolved modeling framework. Some, but not all, of these elements were incorporated into the analysis for this study.

Interregional modeling to capture geographic diversity and electricity flows

A principal finding of this study is the interplay between in-state natural gas resources and economic imports from neighboring regions as a way to balance inter-day renewable energy variability while energy storage balances much of the intra-day fluctuations. We assumed two resources are substitutes for one another; the "gas margin" metric calculated the difference between available gas resources and the combined dispatch of natural gas resources and economic imports. However, with increased natural gas retirements, the availability of imports for reliability could become increasingly important. At the same time, increased renewable integration across the West will change the mix of resources and availability of imports. It is important to fully capture resource availability and transmission flows across the entire region and to conduct resource planning assessments with the larger system in mind.

Power system modeling should include multiple weather years of chronological data

A consistent dataset for chronological wind, solar, and load data across a long historical record (20-30 years) that also reflects drivers to changing load patterns would benefit California and the entire west.

As renewable penetration increases, the power system will become increasingly dependent on the weather that drives renewable resource availability. Capturing a large historical record of weather data to reflect inter-annual weather variability is important. Early renewable integration analysis focused on short-term (sub-hourly) variability, a challenge which battery storage will effectively address. In contrast, future risks will stem from longer periods of sustained low wind and solar production. To characterize this risk, many years of chronological weather data for correlated wind, solar, and load data are needed. This study incorporated 8 years of correlated wind and solar data; data limitations prevented us from incorporating more data and these limitations should be addressed for future studies. While more than 20 years of solar data were available, only 8 years of wind data were available. Currently, there is no long-term production dataset for wind resources in the West spanning more than the 8-year period included in the NREL WIND Toolkit.[62] Another limitation was on the load data side. While the analysis did include 20 years of weather for chronological load data, this data was available for the summer season only. Given the increasing potential for resource shortfalls in the winter months, the load dataset should be expanded. These expanded datasets should reflect different levels of electrification that will change the load shape. Finally, while having overlapping years of wind, solar, and load data is useful, the data should all originate from a single source of weather data—ensuring that wind, solar, and load correlations are maintained.

A consistent dataset for chronological wind, solar, and load data across a long historical record (20-30 years) that also reflects drivers to changing load patterns would benefit California and the entire west.

Modeling tools should capture geographic resource diversity

As noted, weather data will become increasingly important for resource adequacy and production cost simulations. It is important that the representation of renewable resources reflect geographic diversity, particularly, as penetration of renewables increases. For this study, over 250 unique locations were used to develop utility-scale solar PV profiles, and over 140 locations were used for wind profiles. These datasets comprised locations across the Western US to ensure that resource availability was properly correlated to historical weather conditions.

In addition, future analysis should incorporate more diversity in the underlying plant configuration assumptions. For example, solar PV arrays can have different

62 Although new offshore focused datasets have begun to be released by NREL that cover the 21 year period of 2000 to 2020, such as the Offshore CA dataset: https://developer.nrel.gov/docs/wind/wind-toolkit/offshore-ca-download/

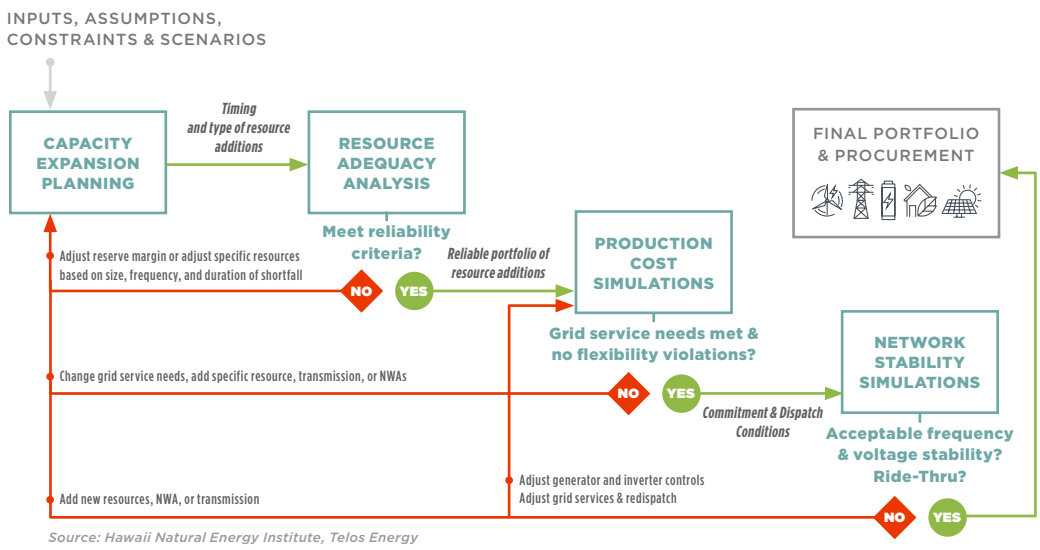
tracking systems and panel orientation that could change the overall plant production profile. Today, renewable plants are designed to maximize total annual energy production due to financial incentives. In a highly renewable system, it may be increasingly important to configure plants to produce energy when it is most needed rather than maximize production,[63] such as solar panels oriented westward to produce more power in the afternoon but less overall energy during the day. Our models and policy should be designed to reflect that. This means capacity expansion modeling should be expanded to include candidate resources that vary not just by region, but also by configuration.

63 The research conducted by the University of California, Merced, on long duration energy storage, supported by the CEC, analyzed the importance of capturing geographic diversity of renewables and technology configurations in power system modeling, and its impact on how much storage and the types of storage that will be needed. This work is in progress but interim results can be found from the November 2021 public workshop: https://www.energy.ca.gov/event/workshop/2021-11/staff-workshop-strategies-model-long-duration-storage

FINDING 9. **Additional analysis is needed**

This analysis does not cover all potential reliability issues associated with hitting an 85% clean electricity target. Assessing clean portfolios with additional sets of weather data, transmission and generator outage conditions, and assessing grid stability are needed as next steps in modeling a reliable power system.

This study is not an end-point in understanding the reliability impacts of an 85% clean electricity target for California. Figure 44 provides an overview of various analytical steps required to ensure system reliability, along with the interdependencies between each step. The figure illustrates that while there are four distinct types of analysis, an iterative process is needed. Depending on the results of a subsequent step, it might be necessary to revisit an earlier step, such as capacity expansion planning.



Source: Hawaii Natural Energy Institute, Telos Energy

FIGURE 44.

Decision Flow Chart and Modeling Steps for Power System Planning and Procurement

We describe the types of analysis that could build on the work conducted in this study, including rate and equity impacts, probabilistic resource adequacy analysis, transmission, and grid stability analysis.

WECC WIDE CLEAN TARGET ASSESSMENT AND RESILIENCE

The study assessed, to some degree, the reliability of WECC-wide decarbonization through the Western Coal Retirement sensitivity. This sensitivity achieves a roughly 67% clean electricity target in 2030. However, we did not analyze the reliability of an 85% clean target WECC-wide. The framework we used in this study could be applied towards that analysis—developing portfolios to achieve a target—and assessing them in a production cost model against multiple system stress factors. These stress factors could include, for example, wildfire risk (and its impact on smoke and renewable generation), and the impact of severe drought on hydro availability.

RATE AND EQUITY IMPACTS

This study evaluated whether or not the California grid could reliably operate under an 85% clean electricity target. While RESOLVE was used to determine least cost portfolios, from a total resource cost perspective, we did not conduct a detailed benefits/costs assessment based on the production cost modeling. Beyond the bulk system, reaching an 85% clean target may require investments on the distribution side, which were not evaluated. How these costs may impact rates, and the equity implications, is an aspect that should be addressed in further analysis.

PROBABILISTIC RESOURCE ADEQUACY ASSESSMENT

While this study included stress tests for specific conditions that could pose a reliability risk to the future California grid, it did not conduct a full probabilistic analysis needed to quantify conventional resource adequacy metrics. To augment the analysis conducted in this study, additional resource adequacy analysis should be conducted that includes drawing hundreds of random generator outage samples. For example, modeling 20 outage samples on each of the 20 weather years would result in 400 total years of simulation and yield more robust results. To further understand the impact of correlated events, generator outages should be tied to underlying physical phenomena, such as cold weather periods, that may drive natural gas limitations and increased equipment failure, along with correlated higher load, and potentially low renewable output. With a complete probabilistic analysis, traditional reliability metrics like loss of load expectation and expected unserved energy could be calculated. Capacity shortfalls can be better characterized, such as on their size, frequency, duration, and timing.

TRANSMISSION NEEDS ASSESSMENT: NODAL MODELING AND DYNAMIC STABILITY ANALYSIS

This study used a “pipe and bubble” zonal model to evaluate the underlying transmission system and considered only zonal and interregional transmission constraints. It did not include a nodal transmission assessment or an N-1 security

constrained economic dispatch. While this information is not necessary for long-term portfolio analysis, it is needed for specific policy decisions, project development, and transmission planning efforts. Given that transmission development typically takes more than 10-years to complete, it is important to start the transmission planning process in lock-step with portfolio design.

A first step in this analysis is to include a full nodal transmission topology in the production cost simulations. A second step is to include a full AC power flow assessment to evaluate steady-state, N-1, and N-1-1 contingency analysis to identify thermal and voltage overloads and local transmission constraints. In California, these efforts are typically conducted by the CAISO and individual balancing authorities. For robust public policy planning, these efforts should also be incorporated into the CPUC and CEC modeling efforts for a more holistic planning process.

An additional needed assessment is related to dynamic transmission stability. As the share of inverter based resources increases on the California grid, additional insight is needed for dynamic stability, including an assessment of grid stability immediately following a disturbance. California transmission could become increasingly constrained by dynamic voltage stability limits, where power flows must be limited such that, during transmission contingency events, system voltage does not collapse. A collapse of system voltage could result in a substantial sudden loss of wind and solar generation, which would severely stress the rest of the California and western grid and likely result in under-frequency load shedding. Potential mitigations for transmission stability could include new inverter controls, additional transmission, and Flexible AC transmission system (FACTS) such as synchronous condensers, STATCOMS, and other advanced technologies.

Finally, this transmission analysis should be conducted in a manner that evaluates a wide spectrum of operating conditions. Typical utility grid planning processes evaluate a limited number of grid conditions for dynamic stability, sometimes as few as two or three “worst-case” snapshots (i.e., summer peak, spring light-load conditions) for a single portfolio. This traditional approach provides limited information for today’s modern grids with high penetrations of variable renewable resources and storage because (1) the “worst-case” periods are shifting and no longer obvious, and (2) this approach provides no indication of how often the grid is exposed to the “worst-case” conditions, which is critical in understand how to best mitigate issues that arise.

Overall, our analysis shows that an 85% clean electricity standard is operable and with the assumptions made here, is resource adequate, even without additional in-state gas being built. However, successful implementation of an 85% clean electricity standard will require understanding local transmission needs, and a thoughtful plan on how to retire gas resources that maintains reliability, while achieving equity and economic objectives.

CONCLUSIONS

OVERALL MESSAGE

The results of this analysis suggest that California can reliably operate a future power system that reaches 85% clean electricity in 2030 that puts the state on a path towards a 100% clean electricity target. There are numerous dimensions of our findings.

- Diverse clean resources have reliability and feasibility benefits but won't happen on its own
- Gas remains important but environmental-justice-sensitive units could potentially be retired
- California still has sufficient imports if clean energy resources replace coal across the West
- The system is reliable against varied weather, although more weather years should be evaluated
- The system is generally reliable against simultaneous system stressors
- Demand flexibility is a tool for reliability and can lower battery needs
- Modeling and planning tools need to evolve to inform smart planning for renewables
- Other types of reliability analysis, such as transmission and grid stability analysis, should be done

An acceleration of the clean electricity transition will not occur on its own and will require coordinated policy, engineering, and market design efforts.

POLICY RECOMMENDATIONS

This report presents results from the technical analysis and does not focus on policy or market design changes that are needed to create an enabling environment. However, a sister report developed by Energy Innovation[64] builds on the analysis in this report, and presents a set of policy recommendations. In summary, these include:

- The state should take an active role to accelerate resource procurement if California is to achieve 85% clean electricity by 2030
- Resource procurement efforts should promote resource diversity, potentially from out of state and offshore wind resources, and firm renewable resources such as geothermal, biomass, or long duration (or increased amounts of short-duration) storage

64 Energy Innovation: Policy and Technology LLC, https://energyinnovation.org/

- Continued efforts related to the state's resource adequacy framework should focus on portfolio attributes and energy adequacy
- State planning should be conducted in a regional context, with interregional coordination and broad west-wide planning initiatives to ensure imports and exports can be used for both economic efficiency and reliability
- The future of in-state natural gas resources should balance opportunities to reduce fixed operations and maintenance costs, environmental justice concerns, and both system and local reliability needs
- The state should continue to facilitate a clean energy portfolio, with portfolio building continuing at the LSE and regulatory levels rather than legislative actions

ANALYSIS AND RESEARCH NEEDS

While this study includes a robust analysis of multi-year weather variability and an assessment of various system stressors on reliability, it is not an end-point in understanding the reliability impacts of an 85% clean electricity target for California. Additional analysis is needed on the following topics:

- Expansion of weather data is needed. While this study used 8 years of correlated wind and solar data, and a larger 22-year dataset of solar and 20-year summer load data, additional data is needed. A long-historical record

of correlated load, wind, solar, and temperature data is required to assess the resource adequacy of the grid under both historical and future weather conditions. This would include, ideally, climate trends and extreme weather events, including specific assessment of wildfire risk and multi-day periods of low wind and solar output

- An assessment of the reliability impacts of WECC-wide decarbonization that builds on the analysis conducted in this study through the coal retirement sensitivity
- A comprehensive cost assessment on the costs and benefits of an accelerated clean electricity target, including rate and equity impacts
- Additional probabilistic resource adequacy analysis that includes hundreds of random draws of generator outages. This would facilitate the calculation of traditional resource adequacy metrics and characteristics of shortfall events, which can inform resource adequacy mitigations steps
- A transmission needs assessment that includes nodal transmission modeling, N-1 security constrained economic dispatch, and dynamic stability assessments
- Further evaluation of battery energy storage and hybrid resource operations is critical. The modeling conducted for this study assumed full system control and a perfect foresight. Actual operations will be based, in large part, on generator offers and uncertainty. Given the increased role of battery storage for reliability, this is an important area for more research as more battery systems come online and provide operating experience.

Taken collectively, these policy recommendations and suggestions for further analysis and research will help ensure that California can continue to meet its ambitious clean energy goals while maintaining reliability and affordability for ratepayers.