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**Climate-Informed Electric Grid
Modeling for California and the West**

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency; renewable energy and advanced clean generation; energy-related environmental protection; transportation; and energy transmission and distribution.

In 2011, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation, and bring ideas from the lab to the marketplace. The EPIC Program is funded by California utility customers under the auspices of the California Public Utilities Commission. The CEC and the state's three largest investor-owned electric utilities — Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company — were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs to promote greater reliability, affordability, and safety for California electric ratepayers. EPIC investments advance these values by:

- Providing societal benefits.
- Reducing greenhouse gas emissions in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs, first with energy efficiency and demand response, next with renewable energy (distributed generation and utility-scale projects), and finally with a clean electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Climate-Informed Electric Grid Modeling for California and the West is the final report for EPC-21-041 conducted by Energy and Environmental Economics, Inc. The information from this project contributes to the CEC Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the [CEC's research website](http://www.energy.ca.gov/research/) (www.energy.ca.gov/research/) or [contact](#) the Energy Research and Development Division at ERDD@energy.ca.gov.

ABSTRACT

This study developed climate-informed data and analytical tools to support long-term electricity system planning in California and the broader Western Electricity Coordinating Council. It produced climate-informed electricity demand and peak load forecasts through mid-century and optimized resource portfolios that meet California’s electric sector decarbonization goals under two different electrification scenarios with different policy assumptions. Results indicated that rising temperatures associated with climate change will increase air conditioning demand and decrease electric space heating demand, generally leading to higher electricity demand in the summer and lower electricity demand in the winter across the WECC, relative to a future without climate change impacts. This study found that the impact of climate change on resource capacity needs could be relatively modest, suggesting that diverse resource portfolios that are optimized to meet clean energy policies, greenhouse gas reduction goals, and reliability requirements contribute to resilience to future climate change. The study suggests that, in a future with high levels of building electrification, warmer winters, and lower winter-time peak demand, there is a lower total capacity build in California, relative to portfolios optimized for historical climate conditions. Lessons learned from the study highlight both the value and the challenges of integrating advanced climate data into grid planning, emphasizing the need for standardized methods, careful interpretation of uncertainty, and close collaboration between planners and climate scientists to support climate-resilient investment decisions.

Keywords: Climate-informed planning, climate change, grid resilience, electricity system modeling, load forecasting

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EXECUTIVE SUMMARY

Project Purpose and Approach

Although electricity system planners in California have begun incorporating climate impacts into various planning efforts, this remains an emerging area of practice for which comprehensive methodologies and best practices are still in the early stages of development. This research study aimed to develop climate-informed energy system planning data and analysis tools for California. Specifically, this study: (1) created a climate-informed annual electric energy and hourly peak demand forecast from now to mid-century for California, designed to meet the state's decarbonization goals, as well as forecasts for the other regions in the Western Electricity Coordinating Council (WECC); and (2) developed optimized electricity system portfolios that reflect future climate impacts and meet California's climate goals, evaluating resource adequacy and resilience to climate impacts and incorporating climate uncertainty. This study offers insights for consideration in regionalized grid planning in the Western United States in a future impacted by climate change, with a focus on the following research questions:

- How might climate change impact reliability risks in the electricity system?
- What are the impacts of incorporating climate-informed load forecasts and renewable generation profiles on long-term electricity generation investment decisions?
- What are the insights and lessons learned from incorporating advanced climate data and modeling techniques into grid planning?

Climate-informed load forecasts and optimized electricity system portfolios were developed for two scenarios that achieve substantially different levels of electrification by the year 2045: a business-as-usual electrification scenario (Reference Electrification), consistent with current economy-wide policies as of 2024, and a high electrification scenario (High Electrification), reflecting policy measures from the California Air Resources Board 2022 Scoping Plan Update as well as net zero policies in other WECC states that would drive higher electrification levels. Historical climate conditions (Baseline Climate) and projected future climate conditions (Future Climate) were analyzed under each electrification scenario, reflecting climate change impacts on future electricity demand and renewable resource availability across the region. Results for Baseline Climate and Future Climate reflected historical simulations and future projections from four different global climate models that were downscaled for the requisite hourly variables of interest for a highly decarbonized electricity system, treating each projection as an equally plausible future. Future projections were based on the medium-high emissions trajectory of Shared Socioeconomic Pathway (SSP) 3-7.0.

Key Results

Electricity Demand:

- **Summer:** In the summer season, electricity demands generally increased as rising temperatures under future climate conditions drove greater adoption of, and demand for, air conditioning.
- **Winter:** The climate-informed load forecasts suggested that winter warming may lead to reduced electricity demand on peak winter days due to decreased space heating load. While a shift in winter months from space heating to space cooling in Southern California and warmer climates was observed, the magnitude of this impact on peak winter loads relative to the impact of reduced space heating demands depended on the amount of future electric space heating. In the High Electrification scenario, the reduction in space heating demand had a larger impact relative to the increase in space cooling load.
- The load forecasts under Future Climate conditions suggested that climate impacts on winter peak loads may be amplified by electrification of space heating and, therefore, climate and electrification impacts should be considered jointly to understand drivers of future electricity demand.

Renewable Resource Availability:

- On average across the WECC, future climate projections indicated a decrease in hydroelectric generation, minimal change to annual average solar capacity factors, and uncertain change to annual average wind capacity factors, with a high degree of variability across downscaled climate projections. However, some differences between regions within the WECC were observed. Analysis performed by collaborating climate scientists suggests that the frequency of coincident solar-and-wind resource drought days may increase under future climate conditions.

Impact on Resource Portfolios:

- **Reference Electrification:** Under business-as-usual electrification, higher summer peak demands and longer loss of load events (10–24 hours) in California increased the value and need for longer-duration storage in the portfolio optimized for Future Climate conditions.
- **High Electrification:** Higher electrification, particularly of space heating through heat pump adoption, increased the total amount of generation capacity need relative to the portfolios optimized for business-as-usual electrification levels. When considering the impact of climate change, some regions, including California, experienced warmer winters that: 1) reduced electric space heating loads, which offset some of the impact of electrification on peak winter electricity demand, and 2) shifted 2045 reliability risk from winter-only to both winter and summer. As a result, California had less total resource needs overall under Future Climate conditions compared to Baseline Climate conditions. These results demonstrated the interdependence between the level of electric space heating and downstream impacts on the grid.

- Although the Future Climate conditions led to differences in resource portfolios relative to Baseline Climate conditions, under the range of conditions tested, these differences were relatively modest, and variations in electrification assumptions had a stronger influence. This demonstrates the need to contextualize climate impacts within the realm of other modeling uncertainties over the study time horizon (e.g., load growth, energy efficiency, and load flexibility, as well as future resource costs).

Lessons Learned

Using forward-looking climate projections in electricity system planning unlocks the potential to plan for risks induced by climate change. However, the underlying data describing hourly projected climate conditions consists of model outputs rather than empirical measurements, raising new questions about validation, consistency, and standard practices for use. Answering these questions requires significant interpretation, and collaborative development of a shared methodological framework leveraging expertise of both electricity system planners and climate scientists. While this project represents an important step in translating climate science into grid-planning-relevant analysis, moving toward a production-grade planning environment fit for making long-term investment decisions will require additional work to standardize methods, clarify appropriate applications, and establish governance around how and which climate data is used.

Throughout the course of this study, the project team identified several lessons learned regarding incorporating climate data into electricity system modeling, which may be considered by future teams as standard practices continue to evolve.

- Incorporating climate data into an electricity system resource planning framework introduces another layer of uncertainty for planners to navigate. Even using only four downscaled climate projections considered in this study, centered around a single future climate scenario (SSP3 – 7.0), inter-model variability was substantial, at times exceeding the underlying climate signal for certain variables. In this study, the project team chose to consider four Weather Research and Forecasting downscaled hourly global climate model results as equally plausible futures. However, the project team did not compare this “equal weighting” approach to the optimized resource portfolios that would have resulted from modeling each downscaled global climate model separately. Future studies utilizing alternative approaches to climate data selection (for example, using Localized Constructed Analogs data) could either validate or modify this study’s findings and may provide additional insights.
- Ingesting climate projections into standard electricity system planning models requires careful translation to transform the direct outputs of high-resolution climate projections into usable model inputs. The project team found that there are many trade-offs to be made in determining which methodology to use in this translation process. For example, the project team faced a practical trade-off between incorporating the full spatiotemporal granularity of the climate data and the computational time required to produce hourly load forecasts and to optimize electricity resource portfolios. For this study, the project team developed various approaches to sampling the climate data to

limit the computational time while still seeking to leverage the richness of the downscaled climate datasets (for example, regional population weighting of the temperature data used in load forecasting and sample day and weather year selection that retained representation across climate datasets in the capacity expansion modeling). The various translation steps required to incorporate the climate data are described throughout this report, including the rationale for the final approaches used.

- Despite the uncertainties that inherently arise when incorporating modeled climate projections and the translation that is needed to ingest the data into the electricity system planning models, the results here provide useful directional insight for planning and suggest a path forward to reflecting future climate impacts in long-term resource planning.

The scope of this study included the entire western interconnection to capture regional grid-weather dynamics that would be possible under future climate conditions (for example, low-hydropower available correlated with hot temperatures). Furthermore, this study ensured that the portfolios in each zone achieve a one-day-in-ten-year loss of load expectation (0.1 LOLE) reliability standard. Electric sector modeling in this study employed a feedback loop between long-term capacity expansion modeling and resource adequacy. The project team observed that this iterative feedback loop played a critical role in defining the ultimate portfolio results, with portfolios and reliability event patterns shifting as iterative adjustments were made. This workflow underscored the importance of considering reliability requirements as a primary driver of climate-informed modeling results.

When zones achieved the same 0.1 LOLE reliability standard, the modeling results identified only limited climate-change-induced interdependencies between zones in the WECC-wide scenarios evaluated here. For example, California portfolios did not change substantially when portfolio compositions changed in surrounding zones.

Summary of Technical Advisory Committee Comments

A Technical Advisory Committee (TAC) was assembled to provide feedback on the project throughout its execution by outside industry experts, including academics and relevant industry members from California utilities, grid operators, and state agencies involved in electricity system planning. Over the course of the project, the TAC met on seven occasions between February 2023 and March 2026. At each TAC meeting, the project team and collaborating climate scientists at Eagle Rock Analytics (who developed climate-informed renewable generation profiles through California Energy Commission research grant EPC-21-037) presented methodology and results to share learnings with TAC members and gather feedback to incorporate as the study progressed. Results were presented to the TAC in October 2025 to review Lawrence Berkeley National Laboratory's electric grid decision flow diagram and stakeholder interview findings related to climate data integration into electric sector planning streams; and in March 2026 to present the final results of the project. Selected TAC feedback included the following points.

- There is a need for planning-relevant analysis that is directly usable for planning and aligned with real processes. The project approach described here reflects decisions that were made to make the study directly applicable for planning processes.
- The TAC noted that climate impacts on the grid expand beyond just those considered in this study, which focused primarily on impacts to electricity demand and renewable resource profiles. While outside of the scope of this study, additional climate impacts include flooding impacts to energy infrastructure, wildfires and smoke-related impacts to solar PV production, and reduced battery performance and thermal efficiency losses under high temperatures. Including these additional factors could be a useful step for future research.
- Climate impacts should be considered in the context of other factors impacting load, such as building electrification, transportation electrification, and large load (for example, data center) growth, all of which play important roles in defining high-risk periods for the grid. This study explicitly evaluates scenarios with varying levels of electrification to better understand these interdependencies.
- The TAC also acknowledged the practical challenges that arise along the path to incorporating climate impacts into electric sector planning processes and expressed a desire to improve consistency on the treatment of climate data across various processes and organizations.

Knowledge Transfer and Next Steps

The project team is committed to sharing the learnings from this work, along with the data and tools developed as part of the study, which will be available from the California Energy Commission upon request. The project team has already taken steps to share key learnings, including through participation in the 2025 EPIC symposium and forthcoming publications.¹ The project team's Interim Report (see Appendix B) focused on electricity demand forecasting using climate-informed data that was developed for, and underwent peer review by, California's Fifth Climate Change Assessment. The project team will continue to seek opportunities to present these findings at future conferences.

¹ Wang, Liyang, Duncan Callaway, Sarah Fletcher, Mark Risser, and Andrew Jones. "Planning for a changing climate: examining future extreme heat event risk for California grid planners." Under review.

CHAPTER 1:

Introduction

Background

Climate change is introducing new and complex challenges for electricity system planners. Rising temperatures and shifting weather patterns are altering both the demand for electricity and the availability of supply resources. On the demand side, higher baseline temperatures and more frequent extreme heat events are expected to increase reliance on air conditioning, accelerating adoption of cooling technologies and raising peak electricity loads.^{2, 3} There is less consensus on how climate change will impact winter temperatures and resulting electricity loads. However, relative to a future that does not account for climate change impacts, the projected trends suggest warmer winters, leading to other impacts on electricity demand, including 1) increased cooling demand even in winter months, in warmer parts of the West, and 2) reduced winter peak heating demands in cooler climates.^{4, 5, 6} On the supply side, climate change can disrupt traditional resource patterns — for example, studies have shown that climate change is likely to impact the total and seasonal availability of hydropower across the Western U.S. and could reduce average wind resource availability.^{7, 8} Together, these shifts create a more uncertain and dynamic planning environment.

California has already experienced firsthand how climate-driven extreme events can strain the electric grid. During the August 2020 heat wave, record-breaking temperatures across the

2 Amonkar, Yash, James Doss-Gollin, David J. Farnham, Vijay Modi, and Upmanu Lall. 2023. "[Differential effects of climate change on average and peak demand for heating and cooling across the contiguous USA](https://doi.org/10.1038/s43247-023-01048-1)." *Communications Earth & Environment*, 4: 402. <https://doi.org/10.1038/s43247-023-01048-1>.

3 Zhang, Hongliang, and Shang Xu. 2025. "[Climate Change, Air Conditioning Adoption, and Household Electricity Use: Evidence from the Northwestern United States](https://www.researchgate.net/publication/393760139_Climate_Change_Air_Conditioning_Adoption_and_Household_Electricity_Use_Evidence_from_the_Northwestern_United_States)." *Environmental and Resource Economics*, 88 (9): 2469-2501. July. https://www.researchgate.net/publication/393760139_Climate_Change_Air_Conditioning_Adoption_and_Household_Electricity_Use_Evidence_from_the_Northwestern_United_States.

4 Filahi, Hajar, Philippe Drobinski, Boutheina Oueslati, Sandra Claudel, and Marie-Hélène Laurent. 2025. "[Rising power system strains despite decreasing heating demand in a warming climate](https://hal.science/hal-05345160v1/document)." *Scientific Reports*, 15 (1): 12470. <https://hal.science/hal-05345160v1/document>.

5 Amonkar, Yash, James Doss-Gollin, David J. Farnham, Vijay Modi, and Upmanu Lall. 2023. "[Differential effects of climate change on average and peak demand for heating and cooling across the contiguous USA](https://doi.org/10.1038/s43247-023-01048-1)." *Communications Earth & Environment*, 4: 402. <https://doi.org/10.1038/s43247-023-01048-1>.

6 Deroubaix, Adrien, Inga Labuhn, Marie Camredon, Benjamin Gaubert, Paul-Arthur Monerie, Max Popp, Johanna Ramarohetra, Yohan Ruprich-Robert, Levi G. Silvers, and Guillaume Siour. 2021. "[Large uncertainties in trends of energy demand for heating and cooling under climate change](https://doi.org/10.1038/s41467-021-25504-8)." *Nature Communications*, 12: 5197. August. <https://doi.org/10.1038/s41467-021-25504-8>.

7 Szinai, Julia K., David Yates, Pedro A. Sánchez-Pérez, Martin Staadecker, Daniel M. Kammen, Andrew Jones, and Patricia Hidalgo-Gonzalez. 2024. "[Climate change and its influence on water systems increases the cost of electricity system decarbonization](https://www.nature.com/articles/s41467-024-54162-9)." *Nature Communications*, 15 (1): 10050. <https://www.nature.com/articles/s41467-024-54162-9>.

8 Chen, Liang. 2020. "Impacts of climate change on wind resources over North America based on NA-CORDEX." *Renewable Energy*, 153: 1428-1438. June.

Western U.S. drove unprecedented electricity demand.⁹ Simultaneously, regional supplies were constrained, causing rolling outages impacting hundreds of thousands of customers across California. Between 2020 and 2025, California ordered the procurement of an additional 16,500 megawatts (MW) of new net qualifying capacity to meet reliability needs by 2028, with battery storage or hybrid solar storage making up the majority of compliance resources thus far.¹⁰ As extreme weather events become more frequent and intense, understanding the implications of climate change is increasingly critical for electricity system planners.

Consideration of climate impacts has become more commonplace across California's various electricity system planning processes, including Integrated Resource Plans (IRP), utility Climate Adaptation Vulnerability Assessment (CAVA), and others, but the methods for incorporating climate data vary across organizations and processes as new best practices are beginning to emerge and evolve.

In the last decade, the electricity system has changed significantly, independent of climate change considerations. Policies and cost declines have led to an increase in wind, solar, and storage deployment, while nuclear and hydropower resource availability has declined. As this trend continues, the grid will become increasingly dependent on new forms of variable, weather-dependent (wind, solar) and energy-limited (storage) resources to serve load, as opposed to gas-powered generation that can largely generate on-demand, but that is also susceptible to water availability for cooling and reduced thermal efficiency under high ambient outdoor temperatures. Additionally, new load growth, driven by data center demand, resurgence of manufacturing, and the electrification of transportation and building end uses, is already underway and is expected to increase future electricity demand at a pace not seen in the past 15 years.¹¹ In addition to increasing overall electricity demand, electrification changes the seasonal and hourly patterns of electricity consumption. For example, replacing gas heating appliances with electric appliances results in a significant increase in winter load, impacting winter electric reliability risk.

Energy systems tools, planning methods, and datasets have all evolved over the past decade to capture the complex, weather-dependent dynamics across loads, resources, and other grid assets. However, few tools have evolved to the point of enabling exploration of long-term climate trends on these weather-dependent dynamics, and existing planning methods are still largely based on extrapolations of historical weather data and are not conducive to evaluating whether the electricity system is robust to multiple potential climate futures. A wide body of planning studies and research has found that the Western U.S. grid will need to expand and

9 California Independent System Operator. 2021. [Root Cause Analysis: Mid-August 2020 Extreme Heat Wave](https://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf). January 13. <https://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf>.

10 California Public Utilities Commission. 2025. ["California Public Utilities Commission \(CPUC\) Staff Review of Load-Serving Entities' \(LSEs'\) Compliance with the Mid-Term Reliability \(MTR, D.21-06-035\) and Supplemental MTR \(SMTR, D.23-02-040\) Decisions."](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/compliance-status-reportmid-term-reliability-mtr-and-supplemental-mtr.pdf) July. <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/compliance-status-reportmid-term-reliability-mtr-and-supplemental-mtr.pdf>.

11 U.S. Energy Information Administration. 2025. ["After more than a decade of little change, U.S. electricity consumption is rising again."](https://www.eia.gov/todayinenergy/detail.php?id=65264) May 13. <https://www.eia.gov/todayinenergy/detail.php?id=65264>.

invest in more generation, transmission, distribution, and demand-side assets in nearly all future scenarios, even without accounting for potential impacts of climate change.^{12, 13}

Prior studies on the effect of climate change on California's electricity system have varied with regards to their conclusions. While a 2013 study by Sathaye et al. suggested that climate change may lead to substantial additional resource capacity needs driven by increased demand,¹⁴ that study did not apply modern grid planning tools, nor did it reflect the more recent prevalence or cost reductions associated with wind, solar and storage across the Western U.S. today. A subsequent study using updated methods and data derived from the Localized Construction Analogs (LOCA) downscaled Coupled Model Intercomparison Project Phase 5 (CMIP5) projections for California, Tarroja et al. 2018, suggested a more modest increase in climate-change-driven resource capacity needs.¹⁵

Project Overview

This project develops climate-informed energy system planning data and analysis tools for California. The project team was led by Energy and Environmental Economics, Inc. (E3) with support from Eagle Rock Analytics, Lawrence Berkeley National Laboratory (LBNL) and Kit Batten Consulting. Eagle Rock Analytics served as subject-matter experts in the use and application of climate data. LBNL conducted interviews with stakeholders about the use of climate-informed data in California resource planning and advised on the modeling framework and model development. The project team created climate-informed electric energy and peak demand forecasts from 2025 to mid-century for California and other regions in the Western Electricity Coordinating Council (WECC) and leveraged climate-informed solar, wind, and hydroelectric generation data developed through another California Energy Commission (CEC)-funded project (EPC-21-037). The team developed optimized electricity system portfolios that reflected future climate impacts and uncertainty while also meeting regional climate goals and reliability standards and then evaluated how climate change could impact the reliability of those portfolios. Lastly, the project team synthesized the lessons learned from incorporating advanced climate data and modeling techniques into electricity system planning.

This study builds on and deepens prior research, by applying new West-wide climate data from the sixth iteration of the Coupled Model Intercomparison Project Phase 6 (CMIP6), downscaled by the University of California, Los Angeles using a dynamical method using the

12 Western Electricity Coordinating Council. 2025. "[2025 Western Assessment of Resource Adequacy](https://feature.wecc.org/2025wara/index.html)." <https://feature.wecc.org/2025wara/index.html>.

13 Western Transmission Expansion Coalition. 2026. "[West-Wide Transmission Study: 10-Year Horizon Report](https://www.westernpowerpool.org/private-media/documents/WestTEC_10-year_Full_Report.pdf)." February. https://www.westernpowerpool.org/private-media/documents/WestTEC_10-year_Full_Report.pdf.

14 Sathaye, Jayant A., Larry L. Dale, Peter H. Larsen, Gary A. Fitts, Kevin Koy, Sarah M. Lewis, and André Frossard Pereira de Lucena. 2013. "[Estimating impacts of warming temperatures on California's electricity system](https://www.sciencedirect.com/science/article/abs/pii/S0959378012001458)." *Global Environmental Change*, 23 (2): 499-511. <https://www.sciencedirect.com/science/article/abs/pii/S0959378012001458>.

15 Tarroja, Brian, Felicia Chiang, Amir AghaKouchak, Scott Samuelsen, Shuba V. Raghavan, Max Wei, Kaiyu Sun, and Tianzhen Hong. 2018. "[Translating climate change and heating system electrification impacts on building energy use to future greenhouse gas emissions and electric grid capacity requirements in California](https://www.sciencedirect.com/science/article/abs/pii/S0306261918306962)." *Applied Energy*, 225: 522-534. <https://www.sciencedirect.com/science/article/abs/pii/S0306261918306962>.

Weather Research and Forecasting (WRF) model.¹⁶ These data are combined with WECC-wide energy systems modeling to examine the impacts of climate change across a range of scenarios. This approach captures the impact of climate change on variable resources (wind, solar, and hydro) and electric loads over a wide range of weather conditions, representing over 30 weather years each across four downscaled global climate models (GCM). For generation and loads, this study considered changes in both the overall (annual) generation and loads, as well as seasonal and hourly patterns. The electric sector modeling methodology employed both long-term capacity expansion (LTCE) modeling and loss of load probability modeling (LOLP) iteratively to capture the impact of a shifting reliability risk period on the final optimized resource portfolios that are designed to meet a one-day-in-ten-year loss of load expectation (0.1 LOLE).

Climate-Informed Electricity System Planning in California

In California, stakeholders have long recognized the need to consider climate change in electric system planning. The California Public Utilities Commission (CPUC) brought climate adaptation matters to the forefront in 2018 with R.18-04-019, "Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Adaptation." In 2019, CPUC Decision 19-10-054 adopted an official definition of climate change adaptation pertaining to energy utilities, and provided initial guidance for the use of tools, models, and data for incorporating climate change into utility planning.¹⁷ This set in motion ongoing efforts to embed climate change considerations into California's electricity system planning, which are divided across many stakeholders, each with distinct roles to play (Table 1).

16 See the [Cal-Adpat Analytics Engine](https://analytics.cal-adapt.org/data/about/) for more information: <https://analytics.cal-adapt.org/data/about/>.

17 California Public Utilities Commission. 2019. [Decision 19-10-054, "Decision on Phase 1 Topics 1 and 2."](https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K075/319075453.PDF) October 24. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K075/319075453.PDF>.

Table 1: Summary of California Long-Term Electricity System Planning Workstreams Across Organizations

Organization	Activity/Product	Frequency	Key Outputs	Look-Ahead
California Energy Commission (CEC)	Integrated Energy Policy Report, Forecasts and System Planning	Biennial for full report, with annual updates	Hourly demand scenarios and peak forecasts	20 years
California Public Utilities Commission (CPUC)	Integrated Resource Plan (IRP) and Long-Term Procurement	Biennial	System plans that meet greenhouse gas, reliability, and cost objectives	10 years for reliability, approximately 20 years for planning portfolios
California Independent System Operator (CAISO) and CPUC	Transmission Planning Process	Annual	Identify transmission needs	10 and 15 years
Load Serving Entities (LSEs)	Integrated Resource Plan (IRP), Risk Assessment Mitigation Phase (RAMP), and Climate Adaptation and Vulnerability Assessments (CAVA)	IRP: biennial; RAMP and CAVA: every 4 years	Procurement needs, risk and climate impacts on infrastructure	IRP: 20 years RAMP: tied to General Rate Case test year period CAVA: uses a Global Warming Level approach for look-ahead (2°C and 2.5°C)

Source: Adapted from research performed under this grant by Liyang Wang, LBNL.

Each piece of the electricity system planning puzzle may present different opportunities for incorporating climate impacts. Following are examples.

- The CEC develops the Integrated Energy Policy Report (IEPR) California Energy Demand forecast where downscaled climate data is incorporated.¹⁸ The IEPR demand forecast is used by state agencies and utilities in integrated resource planning, as well as in the transmission planning process and the 20-year transmission outlook.

¹⁸ Bailey, Stephanie, Mathew Cooper, Quentin Gee, Heidi Javanbakht, Jake McDermott, and Danielle Mullany. 2025. [Final 2024 Integrated Energy Policy Report Update](https://efiling.energy.ca.gov/GetDocument.aspx?tn=266416). California Energy Commission. Publication Number: CEC-100-2024-001-CMF. <https://efiling.energy.ca.gov/GetDocument.aspx?tn=266416>.

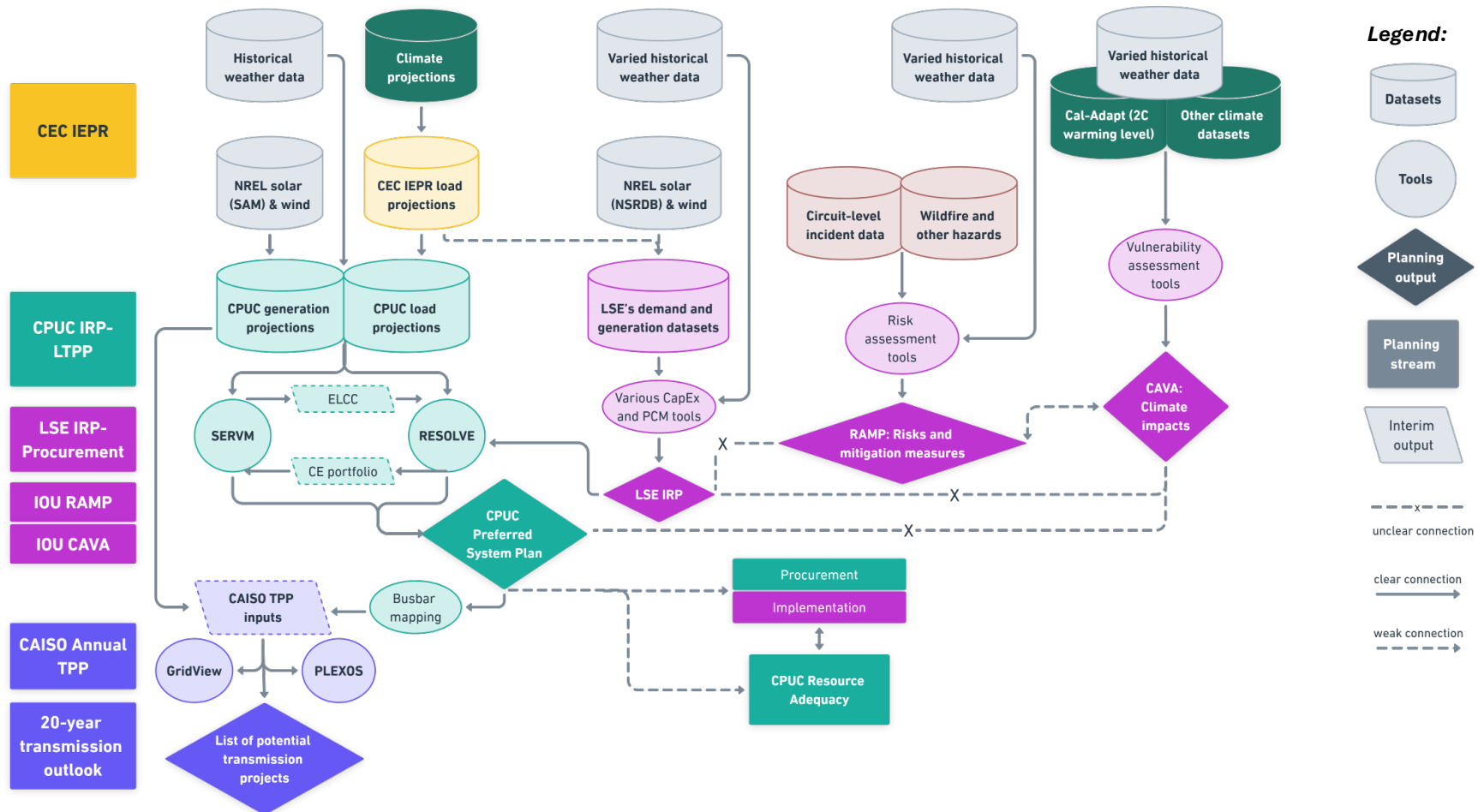
- In the CPUC IRP process, the CPUC ingests climate impacts on loads from the CEC IEPR.
- California energy utilities are required to file a CAVA every four years focused on climate risks to utility operations, which are subject to the CPUC's guidance on incorporating climate data. The impacts considered in utility CAVAs extend beyond temperature changes to supply and demand (for example, extreme storms and flooding, sea-level rise, and wildfire), and the assessment covers a wide range of utility infrastructure.

The CPUC has continued to iterate on guidance provided around the recommended approaches for incorporating climate impacts. For example, in Decision 24-08-005, the CPUC adopted refinements to its original guidance, adopting a specific greenhouse gas scenario—Shared Socioeconomic Pathway (SSP) 3-7.0 to be used as the reference scenario for utilities in their CAVAs and also recommended this scenario for use in other proceedings (for example, for long-term infrastructure planning).¹⁹ The decision also adopted a Global Warming Level (GWL) approach as the basis for CAVA planning and recommended that utilities consider a GWL approach in other proceedings.

The present study is focused specifically on incorporating climate impacts into load forecasts and generation resource planning. However, as shown in Figure 1, this is just one component of the broad set of efforts that flow into electricity system planning in California.

¹⁹ California Public Utilities Commission. 2024. Decision 24-08-005, "[Phase 2 Decision Updating Climate Change Adaptation Modeling Requirements and Refining the Climate Adaptation and Vulnerability Assessments](https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M537/K988/537988980.PDF)." August 1. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M537/K988/537988980.PDF>.

Figure 1. Flow Diagram Illustrating How Climate Data Flows Through Electricity System Planning Processes in California



Source: Adapted from research performed under this grant by Liyang Wang, LBNL.

CHAPTER 2:

Project Approach

Climate Data and Scenarios

Climate Dataset Selection

This study uses climate data from the Cal-Adapt: Analytics Engine (Analytics Engine), an open-source platform supporting analysis for California’s electricity sector. The Analytics Engine offers a wide array of datasets for use in analysis, including downscaled datasets from 15 distinct GCMs that are part of CMIP6.²⁰ The Analytics Engine offers downscaled climate datasets produced using two different downscaling approaches: dynamical downscaling using the WRF applied to 8 GCMs, and hybrid-statistical downscaling using the Localized Constructed Analogs version 2 (LOCA2-Hybrid) applied to 15 GCMs, resulting in a total of 23 downscaled datasets available on the Analytics Engine.²¹

There are tradeoffs between the different climate datasets, which impacted data selection for this study.²² While the LOCA2-Hybrid datasets are available for a wider range of GCMs, data is limited to **daily** temporal resolution and to the California domain. By contrast, the WRF datasets comprise fewer GCMs but provide **hourly** temporal resolution and extend across the western region (enabling WECC-wide analysis). The WRF datasets also provide dynamically consistent variables, meaning that, for a given point in time and space, the different variables within each dataset are internally consistent and obey the laws of physics. Dynamic consistency is important for analyzing compound and cascading climate impacts that depend on interaction of multiple variables across space and time (for example, realistic interactions between temperature-driven electricity demand and renewable resource availability occurring at the same time). In contrast to the LOCA2-Hybrid datasets, the WRF datasets’ hourly resolution, broad geographic coverage, and dynamic consistency made them better-suited for use in this study.

Among the available WRF datasets, further differences in the bias correction influenced their suitability for this study. Following the Analytics Engine guidance, the *a priori* bias-corrected models are more appropriate for use in energy sector analysis.²³ Of the eight WRF-downscaled GCMs, only five had *a priori* bias correction. Four out of these five WRF datasets were chosen for use in this study:²⁴

20 CMIP6 is an international effort across research institutions to produce climate model outputs with consistent standards, as described in the [Analytics Engine Guidance Glossary](https://analytics.cal-adapt.org/guidance/glossary/#cmip6). <https://analytics.cal-adapt.org/guidance/glossary/#cmip6>.

21 [Analytics Engine Data Catalog](https://analytics.cal-adapt.org/data/catalog/) <https://analytics.cal-adapt.org/data/catalog/>.

22 Jagannathan, K., N. Freitas, O. Doherty, A. Jones, and N. Goldenson. 2024. [Guidelines on appropriate use of climate projections in the Analytics Engine \(v1.0\)](https://analytics.cal-adapt.org/guidance/using_in_decision_making). Cal-Adapt: Analytics Engine. https://analytics.cal-adapt.org/guidance/using_in_decision_making.

23 Ibid.

24 EC-Earth3-Veg was not selected for use in this study because it did not contain all of the necessary data inputs (e.g., the requisite hourly wind data).

- EC-Earth3
- MIROC6
- TAI-ESM1
- MPI-ESM1-2-HR

Different GCMs take different approaches to modeling the physics that influence climate. All GCMs available on the Analytics Engine have been pre-selected based on their ability to capture dynamics specific to extreme weather in California, but they vary with respect to how well they represent high-priority variables of interest (for example, extreme precipitation, Santa Ana winds, El Niño Southern Oscillation, and so on), as well as in their sensitivity to atmospheric greenhouse gas (GHG) concentrations (specifically, the amount of warming that results from a given amount of GHG).²⁵ Each of the four chosen downscaled GCMs was treated as an equally-plausible future in this study.

Climate Scenario Selection

There is a substantial uncertainty in how the climate will change in the future, which will be highly dependent on cumulative concentrations of GHG emissions and other global factors. Given this uncertainty, different climate scenarios are defined by the Intergovernmental Panel on Climate Change to represent various plausible futures based on global trends called Shared Socioeconomic Pathways (SSPs). The Cal-Adapt: Analytics Engine offers datasets for three distinct SSPs: SSP2-4.5, SSP3-7.0, and SSP5-8.5, as described in Table 2.

²⁵ Krantz, Will, David Pierce, Naomi Goldenson, and Daniel Cayan. 2021. "[Memorandum on Evaluating Global Climate Models for Studying Regional Climate Change in California](https://www.energy.ca.gov/sites/default/files/2022-09/20220907_CDAWG_MemoEvaluating_GCMs_EPC-20-006_Nov2021-ADA.pdf)," November 29. https://www.energy.ca.gov/sites/default/files/2022-09/20220907_CDAWG_MemoEvaluating_GCMs_EPC-20-006_Nov2021-ADA.pdf.

Table 2. Three of the Common GHG Trajectory Scenarios Hosted on the Analytics Engine

Emissions Trajectory	Definition	Description	Outcome
SSP2-4.5	4.5 watts per meter squared of radiative forcing by the year 2100	Emissions continue at present levels to mid-century and then decline	2.7°C warmer at the end of the century
SSP3-7.0	7.0 watts per meter squared of radiative forcing by the year 2100	Emissions roughly double from current levels by 2100	3.6°C warmer at the end of the century
SSP5-8.5	8.5 watts per meter squared of radiative forcing by the year 2100	Emissions roughly double from current levels by 2050	4.4°C warmer at the end of the century

Source: Cal-Adapt Analytics Engine Guidance²⁶

To ensure that results are directly relevant to electricity planners in California, this study focuses on SSP3-7.0, which the CPUC has recommended as a reference scenario for electricity and gas investor-owned utilities for relevant use-cases.²⁷ While this scenario provides targeted insights for planners, it represents only one of many plausible futures and is more moderate than others, such as SSP5-8.5, limiting the range of outcomes considered.

In recent years, climate assessments increasingly use a GWL approach, evaluating impacts at a specified level of warming rather than a fixed time. While the CPUC recommends phasing in GWLs, this study is framed by a fixed time window (using 2030–2060 climate data to represent a range of weather conditions for a 2045 forecast year) to align with electrification timing across policy scenarios. Key advantages of the GWL approach, such as accommodating a broader number of climate datasets (including “hot models” that appear to warm too quickly but may be used for capturing extremes), are less relevant for this study because model selection was already constrained by bias correction, resolution, and variable consistency, which led to the selection of the above-mentioned four downscaled climate datasets. This limited the practical benefit of a GWL-based approach for this study.

Overview of Modeling Scenarios and Inputs

The project team created climate-informed load forecasts and leveraged climate-informed renewable generation profiles provided by Eagle Rock Analytics and LBNL to study the impacts of incorporating future climate projections into electricity system modeling. Load forecasts and

²⁶ Table reproduced from Analytics Engine, [About Climate Projections & Models](https://analytics.cal-adapt.org/guidance/about_climate_projections_and_models/). https://analytics.cal-adapt.org/guidance/about_climate_projections_and_models/.

²⁷ California Public Utilities Commission. 2024. [Decision 24-08-005, “Phase 2 Decision Updating Climate Change Adaptation Modeling Requirements and Refining the Climate Adaptation and Vulnerability Assessments.”](https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M537/K988/537988980.PDF) August 1. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M537/K988/537988980.PDF>.

resource generation profiles were created using simulations of historical years (Baseline Climate) and future projections (Future Climate) from four dynamically downscaled GCMs, as described previously in the “Climate Data and Scenarios” section. Table 3 shows which weather years were used in LTCE and LOLP modeling under each climate scenario. More details on the methodology used to sample the representative days and select weather years used for reliability constraints in LTCE can be found in the “Long-Term Capacity Expansion Modeling” section.

Table 3. Use of Weather Years in LTCE and LOLP Modeling

Climate Conditions	Weather Years in Each Climate Dataset	GCM	Weather Year(s) Used in LTCE	Weather Year(s) Used in LOLP
Baseline	1981–2013	EC-Earth3	40 days sampled across all historical weather years; subset of weather years used for reliability constraints	All weather years were used
		MIROC6		
		TAI-ESM1		
		MPI-ESM1-2-HR		
Future	2030–2060	EC-Earth3	40 days sampled across all future weather years; subset of weather years used for reliability constraints	All weather years were used
		MIROC6		
		TAI-ESM1		
		MPI-ESM1-2-HR		

Source: Created by Energy and Environmental Economics, Inc.

In addition, the team modeled the impacts of two different electrification scenarios driven by substantially different policies: a business-as-usual electrification scenario (Reference Electrification) consistent with current economy-wide policies as of 2024 and a high electrification scenario (High Electrification) reflecting policy measures from the California Air Resources Board 2022 Scoping Plan for Achieving Carbon Neutrality that would drive widespread electrification across sectors. For regions outside of California in the rest of the WECC, the High Electrification scenario assumes that the states that have committed to achieving net-zero GHG emissions by 2050 are on a high-electrification trajectory, while all other states maintain reference electrification policies, as shown in Table 4. Detailed policy assumptions for each electrification scenario are described in Appendix A: PATHWAYS, Inputs & Assumptions.

Table 4. Policy Assumptions for Reference and High Electrification Scenarios

State	Reference Electrification Scenario	High Electrification Scenario
Arizona	Reference Electrification Policies	High Electrification Policies
Colorado	Reference Electrification Policies	High Electrification Policies
California	Reference Electrification Policies*	High Electrification Policies*
Idaho	Reference Electrification Policies	Reference Electrification Policies
Montana	Reference Electrification Policies	Reference Electrification Policies
Nevada	Reference Electrification Policies	Reference Electrification Policies
New Mexico	Reference Electrification Policies	High Electrification Policies
Oregon	Reference Electrification Policies	High Electrification Policies
Utah	Reference Electrification Policies	Reference Electrification Policies
Washington	Reference Electrification Policies	High Electrification Policies
Wyoming	Reference Electrification Policies	Reference Electrification Policies

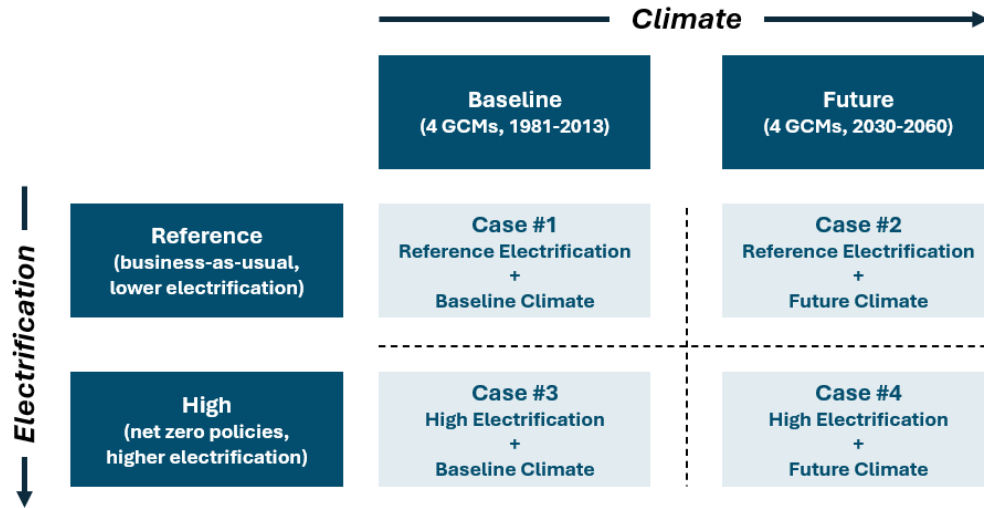
* Under both electrification scenarios, California's policies include a cap on electric sector emissions of 8 MMT (million metric tons) in 2045.

Source: Created by Energy and Environmental Economics, Inc.

Combining the climate and electrification scenarios yielded four core cases for the modeling, which are shown in Figure 2. Each case aimed to model the impacts of different climate change scenarios and electrification policies on electric resource portfolios and the reliability of the electricity system in the year 2045, subject to clean energy goals, GHG reduction targets, and reliability standards while incorporating a range of weather conditions within each climate scenario. The four core cases were:

1. Reference Electrification with Baseline Climate.
2. Reference Electrification with Future Climate.
3. High Electrification with Baseline Climate.
4. High Electrification with Future Climate.

Figure 2. Four Core Cases for Electric Sector Modeling



Source: Created by Energy and Environmental Economics, Inc.

Climate-informed load forecasts accounted for impacts of climate-induced temperature change, including increased adoption of air conditioning, as well as temperature-dependent service demand and technology efficiencies for space heating and space cooling. Four sets of load forecasts were created to represent expected loads in the four core cases. The methodologies used to create the load forecasts are described further in the “Load Forecasting Methodology” section.

Climate-informed generation data accounted for the impacts of climate on solar and wind generation profiles and weekly hydroelectric energy budgets. Capacity factor profiles for utility solar, distributed solar, onshore wind, and offshore wind were developed by Eagle Rock Analytics in another CEC grant, EPC-21-037, for the four downscaled GCMs used in this study. Candidate solar and wind resources in E3’s RESOLVE model were mapped to specific locations based on the publicly available CPUC IRP model, and historical simulated and future projected capacity factor profiles for each candidate solar and wind resource were queried from Eagle Rock Analytics’ database based on the geospatial coordinates.

Weekly hydroelectric energy budgets under historical climate conditions and future climate conditions provided by LBNL were converted to average, maximum, and minimum power (P_{avg} , P_{max} , and P_{min}) profiles. Similar to the solar and wind profiles, the P_{avg} , P_{max} , and P_{min} hydroelectric profiles under both Baseline Climate conditions and Future Climate conditions were filtered for the weather years selected for electric sector modeling (Table 3) and were used as the generation profiles for hydroelectric resources in RESOLVE. The average power was equal to the weekly hydro budget provided by LBNL and was converted to a capacity factor by dividing by nameplate capacity and the number of hours in one week. Reasonable weekly values for P_{max} (above P_{avg}) and P_{min} (below P_{avg}) were calculated based on CPUC IRP data for P_{max} , P_{avg} , and P_{min} across WECC regions.

This study did not account for the impacts of climate change on thermal generation, such as increased forced outages due to higher or lower ambient temperatures in summer and winter

months. Thermal generation plays a key role in ensuring reliability across the western grid. However, empirical data shows little indication that thermal resource outages in WECC are correlated with extreme temperatures in today's system.²⁸ As such, this study chose to model random forced outages but not temperature-correlated forced outages for thermal resources. It is unclear whether this trend will continue under future climate conditions, which could be a valuable area for future research.

Load Forecasting Methodology

Overview of Load Forecasting Methodology

Annual electricity demands were estimated for 2022–2050 for each electrification scenario using E3's PATHWAYS model, which is a bottom-up stock rollover model that accounts for changes in end-use equipment adoption and saturation rates over time and that calculates the resulting energy demands across all sectors of the economy.²⁹ Base-year 2022 electricity and natural gas demands were benchmarked to CEC IEPR data, with other fuels and non-California demands benchmarked to data from the U.S. Energy Information Administration's State Energy Data System (EIA SEDS).³⁰

Hourly load forecasts were developed using a suite of load shaping tools that E3 had previously designed to capture hourly loads for specific end-uses, starting with the annual electricity demands as an input. Separate hourly load shaping tools were used for incremental transportation electrification loads and for incremental building electrification loads — specifically, space heating, space cooling, and water heating, as well as all other loads ("baseload").³¹

Load shapes for baseloads (for example, existing loads, not including electric vehicles [EVs] or new heat pumps) were calculated for Baseline Climate and Future Climate conditions using a neural network model designed to simulate weather-driven load shapes over a long period. Incremental transportation electrification load shapes were developed using E3's bottom-up simulation model that combines driver survey data and utility-specific data with the latest technology and behavioral insights to develop hourly load shapes associated with various charging management strategies. Incremental building electrification loads for space heating, space cooling, and water heating under Baseline Climate and Future Climate scenarios were calculated using estimates of heating and cooling demands as functions of outdoor air temperatures based on the type of heating or cooling device and the device's coefficient of performance (COP).

28 Based on empirical data presented by the National Lab of the Rockies (NLR) Presentation at the North American Electric Reliability Corporation's (NERC) Probabilistic Analysis Forum: Murphy, Sinnott. 2026. "[Extending temperature-dependent generator outage modeling to CONUS](#)." NERC Probabilistic Analysis Forum 2026. March 12. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/pawg/20260312_paf_forum_day_3_presentations.pdf.

29 [E3 Tools: PATHWAYS](#) <https://www.ethree.com/tools/pathways-model/>.

30 U.S. Energy Information Administration. [State Energy Data System](#). <https://www.eia.gov/state/seds/>.

31 Incremental loads were measured relative to 2022 annual electricity demands for each end-use.

Methodology for Modeling Climate Impacts on Loads

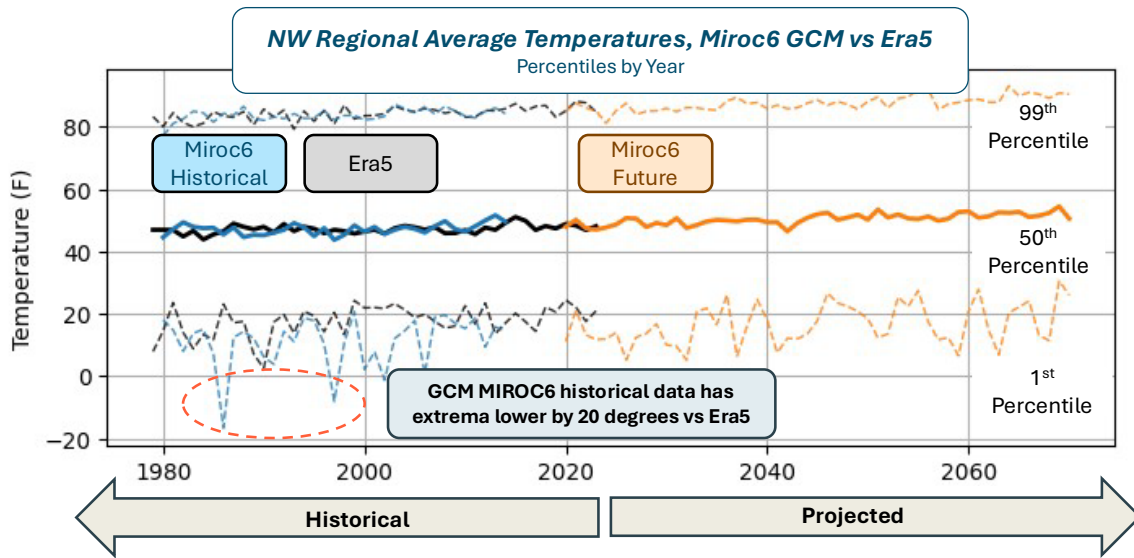
The climate-informed load forecasts leveraged hourly temperature data from the four selected downscaled GCMs at a 3-kilometer (km) spatial resolution within California and a 9-km spatial resolution across the rest of the WECC. The following three primary effects of changing temperature due to climate change were identified and modeled as part of the climate-informed load forecasts.

1. **Increased adoption of air conditioning due to rising temperatures.** Future AC adoption was estimated using a logistic regression model trained on historical data from the Residential Appliance Saturation Study and five-year averages of cooling degree days from the downscaled climate projections. The resulting forecasts reflect an increased number of AC units operating in future years based on temperature projections from the four downscaled GCMs. AC adoption was estimated at the county level across California and at the state level for the rest of the WECC.
2. **Changes to service demand for heating and cooling due to changing temperatures.** Service demand impacts were modeled for hourly heating and cooling loads, taking climate-informed outdoor air temperature data as an input.
3. **Changes to device efficiency for heaters and air conditioners due to changes in temperature.** Device efficiency impacts were modeled for hourly heating and cooling loads, capturing changes to device COP as a function of climate-informed outdoor temperature.

Temperature data from the downscaled climate datasets was preprocessed for use in the load forecasting models. To ensure that climate data inputs for temperature reflected locations where electricity was used, a population-weighted average was applied to the temperature data using the population and temperature data for the five most populous locations within a county. This mitigated the potential for overweighting data from the climate projections that pertained to regions of little-to-no electricity demand. Preprocessing was also needed to ensure that input data used to reflect historical climate conditions was aligned with observed statistics to produce realistic load forecasts. Collaborating climate scientists recommended using simulated data for historical years from each of the downscaled GCMs rather than ERA5 (European Centre for Medium-Range Weather Forecasts Reanalysis v5) data for better consistency between historical and future climate signals.³² However, some downscaled historical data deviated too dramatically from observed weather to appear plausible, particularly winter cold snaps in the northwestern WECC, where downscaled GCMs showed temperatures up to 20°F below historical minima (Figure 3). To maintain realistic ranges while preserving climate trends, E3 clipped these temperatures to the observed county-level historical minima from ERA5 data.

³² Climate scientists were engaged through CEC grant number EPC-21-037, Climate-Informed Generation Capacity Modeling to Support a Climate Resilient Transition to a Clean Electricity System, Eagle Rock Analytics, Inc.

Figure 3. Regional Average Temperature Comparison Between Downscaled MIROC6 and ERA5 Data for Northwest Region



Source: Created by authors using data from Cal-Adapt

Additional details on the load forecasting methodology employed for this study can be found in the Interim Report for this study, *Climate-Informed Load Forecasting for California*.

Electric Sector Modeling Methodology

This project utilized E3's RESOLVE LTCE and Renewable Energy Capacity Planning Model (RECAP) LOLP models to develop optimal portfolios for the different climate and electrification scenarios and to assess the impact of climate change on the nature and drivers of electricity system reliability risks. RESOLVE and RECAP are well-established LTCE and LOLP tools that are commonly used in electricity system planning today. This project expanded beyond conventional system planning practices by using climate-informed datasets and modeling interregional effects. While California was the focus of the analysis, this study modeled all regions in the WECC to capture extreme weather events that affect multiple regions simultaneously. Historical incidents such as the August 2020 heat wave that pushed electricity demand across the Western U.S. to unprecedented levels motivated the decision to pursue WECC-wide modeling, although specific historical events were not recreated in this study due to the reliance on simulations of historical climate conditions using GCM data rather than historical climate records.

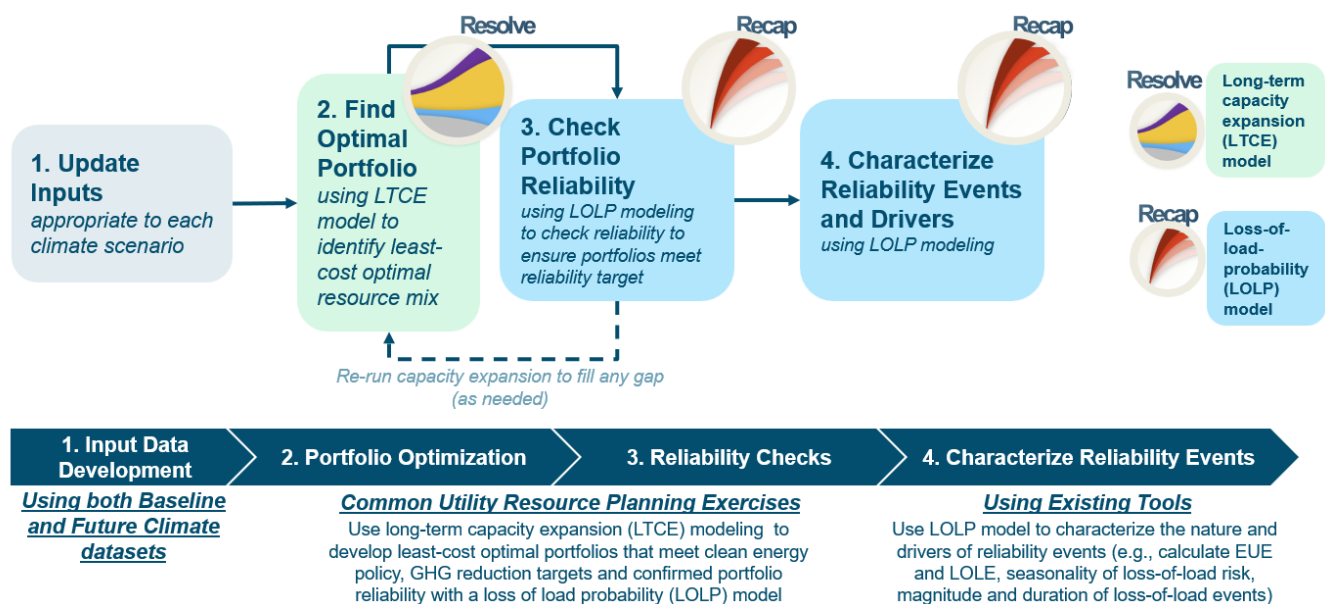
The modeling approach used in this study was a four-step process that included iterative refining of key inputs in between the second and third steps.

1. The team constructed key input datasets, including climate-informed load forecasts, characterizations of existing and potential generation and transmission assets, and climate-informed generation data under the four core cases: Reference Electrification with Baseline Climate, Reference Electrification with Future Climate, High Electrification with Baseline Climate, and High Electrification with Future Climate.

2. The team employed RESOLVE to develop optimal resource portfolios that met clean energy policies, GHG reduction targets, and reliability requirements.
3. The team performed a check on whether the reliability requirement inputs to RESOLVE were sufficient to meet the 1-day-in-10-year or 0.1 days per year LOLE target using RECAP, populated with climate-informed weather and load data.
 - a. The second and third steps were iterated, increasing or decreasing the reliability requirement inputs as needed, until all zones met the LOLE target.
4. The team characterized the nature and drivers of reliability events across the four cases in RECAP to assess the impacts of climate change under both Reference Electrification and High Electrification.

The four-step modeling framework is illustrated in Figure 4. This framework largely follows practices that many utilities' resource planning teams used today and follows the "Adaptive Stress Period Planning" framework described by authors Kuna et al. in their 2024 report *Beyond Capacity Credits: Adaptive Stress Period Planning for Evolving Power Systems*.³³

Figure 4. Electric Sector Modeling Framework



Source: Created by Energy and Environmental Economics, Inc.

Long-Term Capacity Expansion Modeling

The project team used RESOLVE, E3's long-term capacity expansion model, to develop optimal resource portfolios for model year 2045 that met clean energy policies, GHG reduction targets, and reliability requirements. RESOLVE is formulated as a linear optimization problem. It co-optimizes investment and dispatch decisions for a selected set of representative days to

³³ Kuna, Jess, Gord Stephen, and Trieu Mai. 2024. *Beyond Capacity Credits: Adaptive Stress Period Planning for Evolving Power Systems*. No. NREL/TP-6A40-89386. National Renewable Energy Laboratory (NREL), Golden, Colorado. May. <https://docs.nrel.gov/docs/fy24osti/89386.pdf>.

identify least-cost portfolios that satisfy system constraints (for example, reliability requirements, policy goals) across a range of potential weather conditions. The candidate resources that RESOLVE could choose to build included solar (utility-scale and distributed), wind (onshore or offshore), shorter-duration storage (4-hour battery storage), longer-duration storage (8-hour battery storage, 12-hour generic storage, 24-hour generic storage, 100-hour generic storage, or location-constrained storage which includes both pumped hydro storage and adiabatic compressed air storage), biomass, geothermal (conventional or enhanced), and natural gas (combined cycle, combustion turbine, or reciprocating engine), subject to resource potential constraints. Resource potential assumptions as well as resource costs were drawn from the CPUC IRP.³⁴

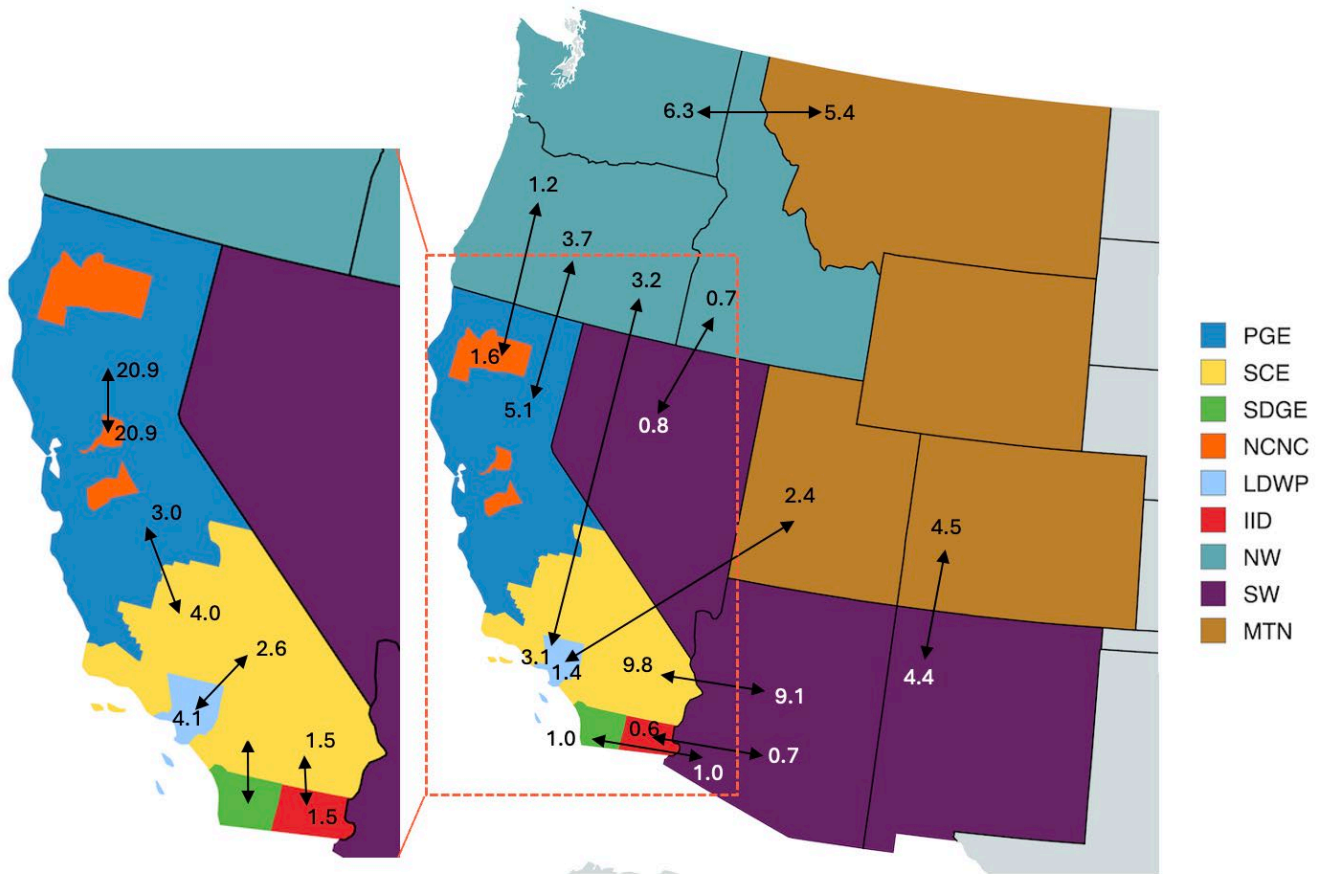
Figure 5 shows the existing path limits on major transmission paths modeled in RESOLVE and illustrates the model's topology. Transmission expansion potential and cost assumptions were drawn from the CPUC IRP.³⁵ RESOLVE was allowed to expand the Pacific Gas and Electric-to-Southern California Edison transmission path to increase its capacity by up to 5.5 gigawatts (GW). The transmission zones modeled in RESOLVE were Pacific Gas and Electric, Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Northern California Non-CAISO, Los Angeles Department of Water and Power, Imperial Irrigation District, Northwest, Southwest, and Mountain. Transmission paths with less than 0.5 GW capacity are not shown on Figure 5 for simplicity, and path locations are illustrative only. This study did not consider intra-zonal path ratings due to limited additional benefits towards understanding the climate impacts on the selected resource portfolio.

34 California Public Utilities Commission. 2026. [2024-2026 Integrated Resource Planning \(IRP\): Inputs & Assumptions](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf). February. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf.

35 Ibid.

Figure 5. Map of Major Transmission Paths in RESOLVE (Existing Path Limits in GW)

36



Source: Created by Energy and Environmental Economics, Inc.

The policy and reliability constraints applied in RESOLVE included clean energy goals, GHG emissions targets, and reliability requirements. The project team modeled California with a clean energy standard (CES) constraint of 100 percent retail sales in 2045 to align with existing state policies. California was the only region to which the project team applied an explicit GHG emissions target, capping electric sector emissions at 8 MMT in 2045 based on the California Air Resource Board's Scoping Plan. For the rest of the WECC, each RESOLVE zone was modeled with a CES constraint expressed as a minimum percentage of sales that must be supplied by zero-carbon electricity generation (net of imports and exports), which represented a weighted average policy target (weighted based on state load share) across the states within a particular zone. The project team converted any state-level GHG target outside of California to an equivalent CES target. For states without GHG targets, CES, or a Renewable Portfolio Standard, the team calculated the CES constraint based on the achieved percent of clean energy in the most recent IRPs completed by the state's major utilities. This resulted in CES constraints of approximately 98 percent for Northwest, 82 percent for Southwest, and 87 percent for Mountain. The CES constraints varied slightly between climate and electrification

36 No limits are shown on the SCE-to-SDGE transmission path. The SCE-to-SDGE transmission path was modeled as effectively unconstrained due to CAISO transmission upgrades planned for completion in the 2030s.

scenarios due to differences in load growth assumptions. For the reliability requirement, the project team used an Energy Reserve Margin (ERM) constraint to achieve a reliability standard of 0.1 LOLE. This approach enforced a reserve margin above hourly load in which RESOLVE must build sufficient resources to meet hourly load and its reserve margin. The setup of the ERM constraint is described in more detail in a subsequent section (see the “Selection and usage of extreme weather years in LTCE modeling” section).

To capture the range of weather conditions across the GCMs, RESOLVE used the hourly climate data in two different ways: (1) to represent 2045 average weather conditions through 40 representative days, and (2) to represent 2045 extreme weather conditions through four specific weather years. The average conditions served to optimize grid operations (hourly supply-demand balance) while satisfying emissions targets and clean energy policy constraints. The extreme weather conditions represented the hourly energy balancing needs to achieve a one-in-ten-day LOLE. Ideally, RESOLVE would use all weather years across each downscaled GCM, but computational limits prevented the project team from using all weather years. The following sections describe the methodology to derive the average and extreme weather conditions represented in RESOLVE.

Selection and Usage of 40 Representative Days for Average Conditions in LTCE Modeling

To derive average conditions for grid operations, all weather years across each GCM were fed into a clustering algorithm. The clustering algorithm’s objective was to minimize the distance between the full dataset with all weather years and the 40 representative days, which best-approximated the average weather conditions. Two sets of 40 representative days were produced, one for the Baseline Climate dataset and one for the Future Climate dataset. The 40 days were then mapped to a full calendar year for RESOLVE to optimize electric sector operations. To achieve an even representation of equally plausible climate futures, the team forced the clustering algorithm to select 10 representative days from each of the four downscaled GCMs for both Baseline Climate and Future Climate.

The team performed various checks to ensure that the 40 days selected by the clustering algorithm for each climate scenario were an adequate representative sample of weather conditions for a median weather year. First, the team checked that the same day was not selected twice from the different GCMs. The team validated that the 40 representative days had an even distribution across seasons and that the ratio of weekday to weekend days was close to 5:2. In addition, the team compared the distribution of maximum and minimum daily temperatures between the 40 representative days and the full weather-year dataset and ensured that both the median temperature and overall shape of the temperature distributions were similar.

These 40 representative days were used to model grid operations, or the dispatch of supply-side resources to meet hourly demand, as well as compliance with clean energy policies and GHG emissions targets. Dispatch in each sample day is typically modeled in RESOLVE as independent from other days by default, but inter-day energy sharing was enabled in this study for longer-duration storage resources so that their dispatch could be optimized across multiple days. Inter-day energy sharing allowed storage to charge over longer periods when

excess renewables were available and to shift discharge to another day or even to discharge stored energy across multiple days. This inter-day energy sharing feature also took chronological order of days into account.

Selection and Usage of Extreme Weather Years in LTCE Modeling

Separate from the 40 representative days, RESOLVE considered additional constraints to capture a broader range of extreme weather. The constraints ensure that portfolios meet reliability across a wide range of weather conditions, allowing up to 1 day of loss load for every 10 years (or 0.1 day per year) LOLE reliability standard. This study considered two frameworks to capture reliability constraints: a seasonal Planning Reserve Margin (PRM) with Effective Load Carrying Capability (ELCC) framework and an hourly ERM with Hourly Expected Capacity (HEC) framework.³⁷ While both frameworks are capable of capturing different weather under different climate scenarios, the study team chose to use the ERM and HEC approach for two main reasons: (1) hourly reliability constraints allow for direct representation of extreme weather conditions within LTCE modeling, and (2) they reduce computational complexity, which was beneficial in this study due to the additional computational needs to process the large climate dataset.

This study used an additional four full weather years (4 years x 8760 hours per year) of dynamically consistent hourly resource availability and load. For the hourly resource availability, the weather-correlated generation profiles represented the HEC, capturing both the energy and capacity contributions for wind, solar, and hydro. For the hourly load, the ERM was expressed as a percentage of hourly load for a particular zone. There were five ERM zones in the RESOLVE model: Northern California, Southern California, Northwest (Washington, Oregon, and Idaho), Southwest (Nevada, Arizona, and New Mexico), and Mountain (Montana, Wyoming, Utah and Colorado). The ERM approach is further described in the paper by Kuna et al., Hawaiian Electric's Technical Advisory Panel Resource Adequacy Subgroup Presentation,³⁸ and in author Gordon Stephen's dissertation.³⁹

Similar to the average conditions, two sets of four weather years were chosen: one weather year per downscaled GCM for the Baseline Climate cases and one weather year per GCM for the Future Climate cases. Each set reflected the impacts of weather variability on load, solar, wind, and hydro generation. To determine which weather years were used for the ERM constraint in the Baseline Climate cases, the team calculated the WECC-wide peak demand based on forecasted 2045 loads for each weather year and GCM, and it then selected the weather year across the full weather-year dataset (1981–2013) with the 1-in-10 (90th percentile) peak in each GCM. The same four weather years were used for the Baseline

37 Discussion between the two frameworks (PRM and ELCC versus ERM and HEC) can be found in Hawaiian Electric's Integrated Grid Planning stakeholder documents ([Hawaiian Electric Resource Adequacy \[July 2023\]](https://www.hawaiianelectric.com/a/12523) <https://www.hawaiianelectric.com/a/12523> and [Hawaiian Electric Resource Adequacy \[November 2023\]](https://www.hawaiianelectric.com/a/13185) <https://www.hawaiianelectric.com/a/13185>).

38 Hawaiian Electric. 2021. "[IGP TAP – Resource Adequacy Subgroup: Energy Reserve Margin Criteria Analyses](https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/technical_advisory_panel/20211101_tap_meeting_presentation_materials.pdf)." November 1. https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/technical_advisory_panel/20211101_tap_meeting_presentation_materials.pdf.

39 Stephen, Gordon. 2025. [Enhanced Representations of Probabilistic Resource Adequacy Risk in Power System Capacity Expansion Modeling](https://digital.lib.washington.edu/server/api/core/bitstreams/9d0660e0-572f-458a-b27e-46a51064f908/content). Ph.D. diss., University of Washington. <https://digital.lib.washington.edu/server/api/core/bitstreams/9d0660e0-572f-458a-b27e-46a51064f908/content>.

Climate cases under both electrification scenarios. A similar process was used to select the weather years for the ERM constraint in the Future Climate cases, except from the full weather-year dataset based on future climate projections (2030–2060).

Ideally, all weather years would have been represented in the ERM to balance broader representation of possible weather conditions. However, computation limits in RESOLVE prevented including additional weather years beyond the four selected for each scenario. It is important to note that the achieved portfolio reliability was further explored in the LOLP modeling performed in RECAP. RECAP modeling tests portfolios across the full set of weather years (1981–2013 x 4 GCMs for the Baseline Climate cases and 2030–2060 x 4 GCMs for the Future Climate cases).

Loss of Load Probability Modeling

The project team performed reliability checks and characterized the nature and drivers of reliability events using RECAP. RECAP is E3's LOLP model and is designed to evaluate the resource adequacy of electric power systems, including systems with high penetrations of renewable energy and other dispatch-limited resources such as hydropower, energy storage, and demand response. RECAP simulated electricity system resource availability with a specific set of generating resources and loads under a wide variety of weather years and random forced outages of thermal power plants. After performing time-sequential simulations of hundreds of years of plausible system conditions, RECAP calculated a statistically significant measure of several important system reliability metrics, such as the amount of expected unserved energy (EUE, in megawatt-hours) and LOLE.⁴⁰ A zonal configuration across the WECC enabled optimized import and export capability between zones, subject to transmission constraints and aimed at minimizing loss of load. Inter-zonal transfers were represented to allow visibility into the reliability implications of any extreme weather events that affected multiple zones simultaneously. However, intra-zonal transmission constraints were not represented because of limited additional benefits in terms of understanding the dynamics of coincident weather-related WECC-wide reliability events.

RECAP was used to check the reliability of the optimal portfolios produced by RESOLVE and to calibrate the ERM inputs. For this study, the team defined a **reliable** electricity system as one that meets the 1-day-in-10-year LOLE standard. The team used the full range of weather years in RECAP modeling: 1981–2013 x 4 GCMs for the Baseline Climate cases and 2030–2060 x 4 GCMs for the Future Climate cases. The team optimized zonal dispatch between five distinct zones — Northern California, Southern California, Northwest, Southwest, and Mountain — such that EUE and LOLE were minimized subject to transfer limits and energy limitations across the full time horizon. If a particular zone was found to be over- or under-reliable, the ERM target was decreased or increased, respectively, and then the team repeated portfolio

⁴⁰ LOLE, loss of load expectation, is the average number of days per year in which unserved energy occurs due to system demand plus reserves exceeding available generating capacity.

optimization in RESOLVE. This iterative process continued until all zones met the 1-day-in-10-year standard.⁴¹

In addition, the team used RECAP to characterize the nature and drivers of reliability events by leveraging RECAP's advanced reporting capabilities, including dispatch charts for days with loss of load, the loss of load probability for each hour of the year, and the magnitude and duration of loss of load events. These analyses also provided insight into why different resources were selected by RESOLVE under Baseline Climate and Future Climate conditions.

Feedback Loop Between Electric Sector Models

The iterative process of developing the reliability requirement inputs added significant complexity to the project team's electric sector modeling efforts and ultimately defined the final portfolio and reliability results for the four cases considered in this study. The purpose of introducing LOLP modeling was to ensure that portfolios could be compared relative to the same level of achieved reliability. This study used a 0.1 LOLE standard for each zone and each scenario. Nearly 200 different portfolios were created over the course of the study as the project team refined its inputs and assumptions and tested different sensitivities. The majority of LTCE modeling runs in RESOLVE were conducted to test how varying the ERM values changed the portfolio size and compositions for different regions within the WECC, and, likewise, most LOLP modeling runs in RECAP were performed to determine whether the portfolios produced by RESOLVE met the 0.1 LOLE reliability standard. The team started the ERM calibration process assuming a 14-percent ERM for each ERM zone in RESOLVE, and the reliability of the resulting portfolios was checked in RECAP. If the portfolio was over-reliable relative to the 0.1 LOLE standard, then the team decreased the ERM constraint in the next RESOLVE run, and, conversely, if the portfolio was under-reliable, then the team increased the ERM constraint. However, since inter-zonal transfers were allowed in RECAP, changing the ERM constraint for one zone could affect the resulting LOLE for other zones and the magnitude of impact on other zones was difficult to predict. As a result, finding the combination of ERM constraints for different zones under which all zones would be reliable was a non-linear and time-intensive process. In addition, major updates to other inputs and assumptions usually required a recalibration of the ERM constraints.

Once all portfolios and scenarios achieved the same 0.1 LOLE reliability standard, the team observed significant differences to the size and composition of portfolios as well as the nature of reliability events, compared to the initial starting portfolios. For example, an over-reliable portfolio created for California in the High Electrification with Future Climate case had only winter risk, but, as the ERM target was lowered, several changes occurred: (1) total capacity built by RESOLVE decreased significantly, (2) RESOLVE selected different types of resources (for example, selected capacity from 100-hour storage decreased from 2.3 GW to 0.1 GW), and (3) loss of load risk shifted to be dual-season in both summer and winter. This is just one example of why developing accurate resource adequacy inputs for LTCE is essential for electric

⁴¹ In practice, the team encountered challenges with calibrating all five zones to exactly meet the 1-day-in-10-year (i.e., 0.1 days/year) reliability standard for each climate scenario. For this project, a zone was considered sufficiently reliable if the LOLE was between 0.04 and 0.11 days/year.

sector modeling and demonstrates how the ERM constraints drove many of the results in this study.

Climate-Impacted Supply and Demand Inputs for Electric Sector Modeling

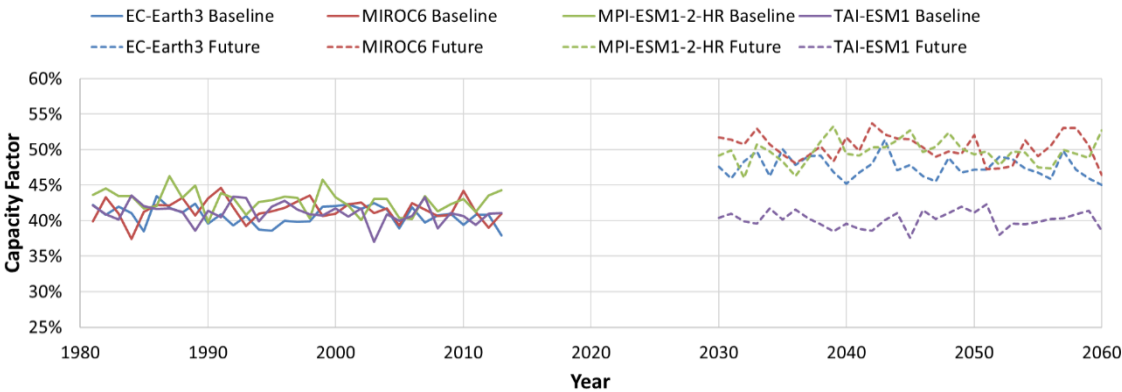
Climate Impacts on Electricity Supply

The project team observed that the impacts of the future climate on renewable resource profiles created using historical simulations and future projections from the selected GCMs varied significantly by resource type. Hydroelectric energy production decreased due to climate impacts in the climate datasets used in this study, but climate impacts on wind generation were unclear and varied significantly between climate datasets. Climate impacts on solar generation were minimal across datasets.

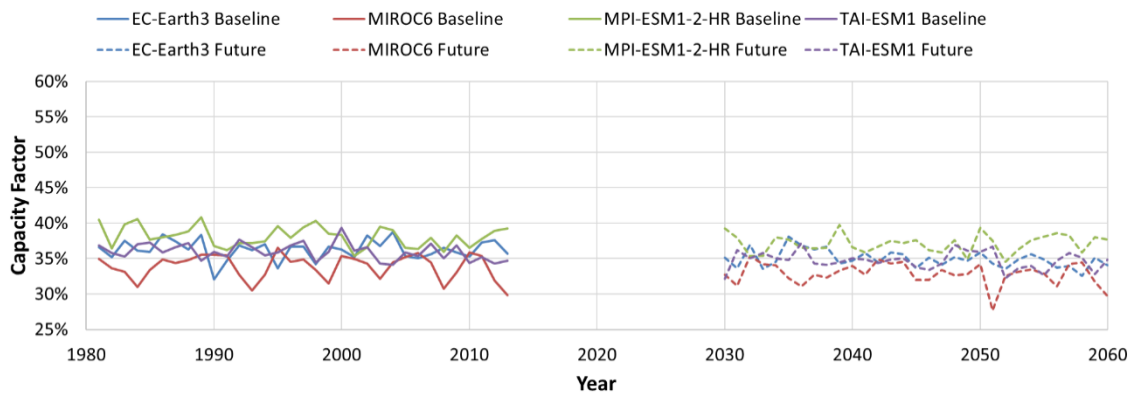
Hydroelectric resource capacity factors were projected to decrease under Future Climate conditions. While average capacity factors increased slightly for February, March, and April, the average capacity factors for all other months decreased, resulting in an overall decline in annual average capacity factor.

The impact of future climate conditions on wind was unclear based on the wind generation projections used in this study. Figure 6(a) shows the annual capacity factors averaged across California onshore wind resources and Figure 6(b) shows the annual capacity factors averaged across onshore wind resources in the WECC outside of California. While annual average capacity factors for onshore wind resources in the WECC outside of California were relatively unchanged between Baseline Climate and Future Climate conditions, the annual average capacity factor increased under the Future Climate conditions for most onshore wind resources in California in all GCMs except TAI-ESM1. Across all GCMs, the annual average factor had a high degree of variability between years.

Figure 6. Annual Average Onshore Wind Capacity Factors Across Weather Years



(a) California



(b) WECC Outside of California

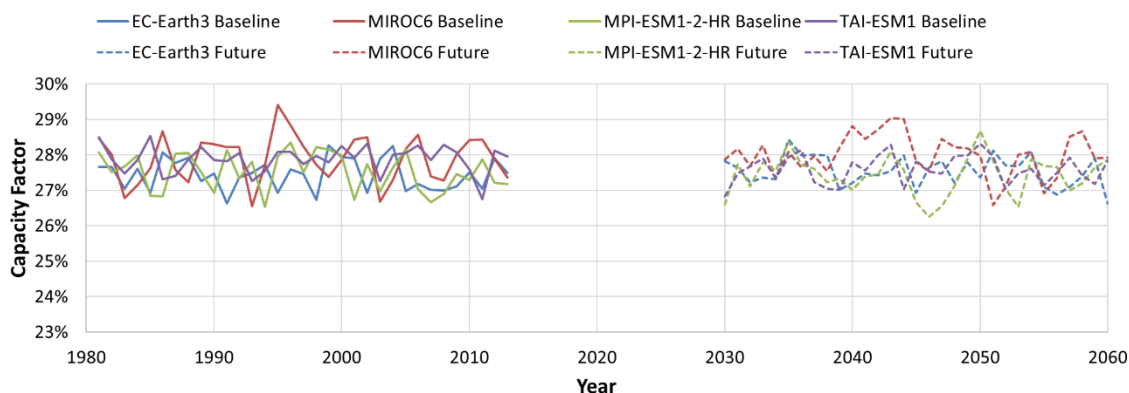
Source: Created by Energy and Environmental Economics, Inc.

The team benchmarked the wind profiles against those used for the CPUC IRP and found that the annual average capacity factors of wind profiles used in this study were generally 30–50 percent higher than wind capacity factors in the CPUC IRP for the same geographic location.⁴² CPUC wind profiles are the outputs of a wind simulation model that takes historic windspeed data and estimates the hourly wind generation per unit of installed capacity. In addition, in both California and the Northwest, the wind profiles had higher summer than winter generation in both the Baseline Climate and the Future Climate cases, whereas the CPUC wind profiles had higher winter than summer generation. The project team explored applying a scaling factor to the wind profiles in both the Baseline Climate and Future Climate cases, such that the average capacity factor of the wind profiles used in the Baseline Climate cases would be more similar to the average capacity factor of the CPUC wind profiles, but the RESOLVE model responded by increasing the installed capacity of wind to make up for the decrease in the capacity factor. As a result, the project team decided to use the wind profiles without any adjustments but it acknowledges that potential overestimation of wind capacity factors may affect the portfolio composition. However, since the wind capacity factors were high under both Baseline Climate and Future Climate conditions, the project team hypothesized that the relative differences between the portfolios optimized for Baseline Climate and Future Climate conditions would hold true even if a more conservative wind simulation model has been used.

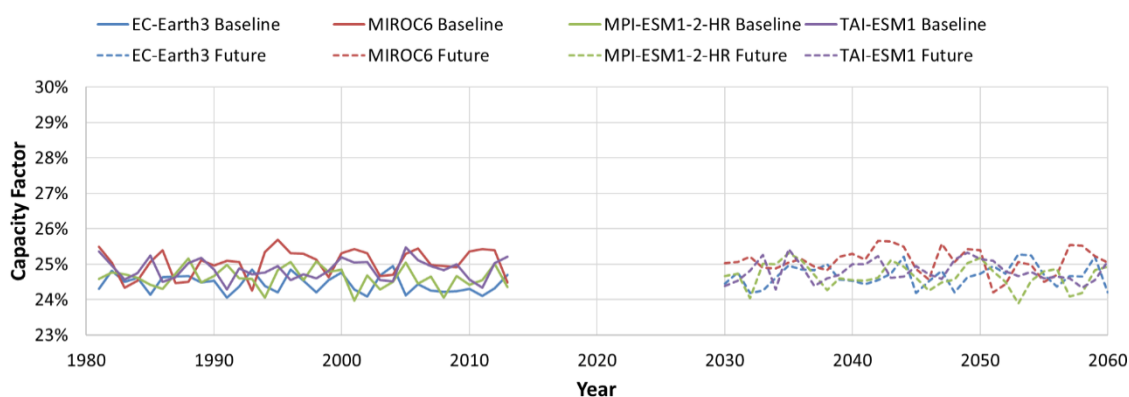
In contrast, solar generation was relatively unaffected by climate impacts. Figure 7 (a) shows the annual capacity factors averaged across California utility-scale photovoltaic solar resources and Figure 7 (b) shows the annual capacity factors averaged across utility-scale photovoltaic solar resources in the WECC outside of California. Across all of the WECC, there was almost no change in annual average solar capacity factors between the Baseline Climate and Future Climate conditions. In addition, there was much less inter-year variability in capacity factors for solar compared to wind, which is evident in the smaller range of capacity factors on the vertical axes.

⁴² California Public Utilities Commission. 2026. [2024-2026 Integrated Resource Planning \(IRP\): Inputs & Assumptions](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf). February. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf.

Figure 7. Annual Average Utility-Scale Solar Capacity Factors Across Weather Years



(a) California



(b) WECC Outside of California

Source: Created by Energy and Environmental Economics, Inc.

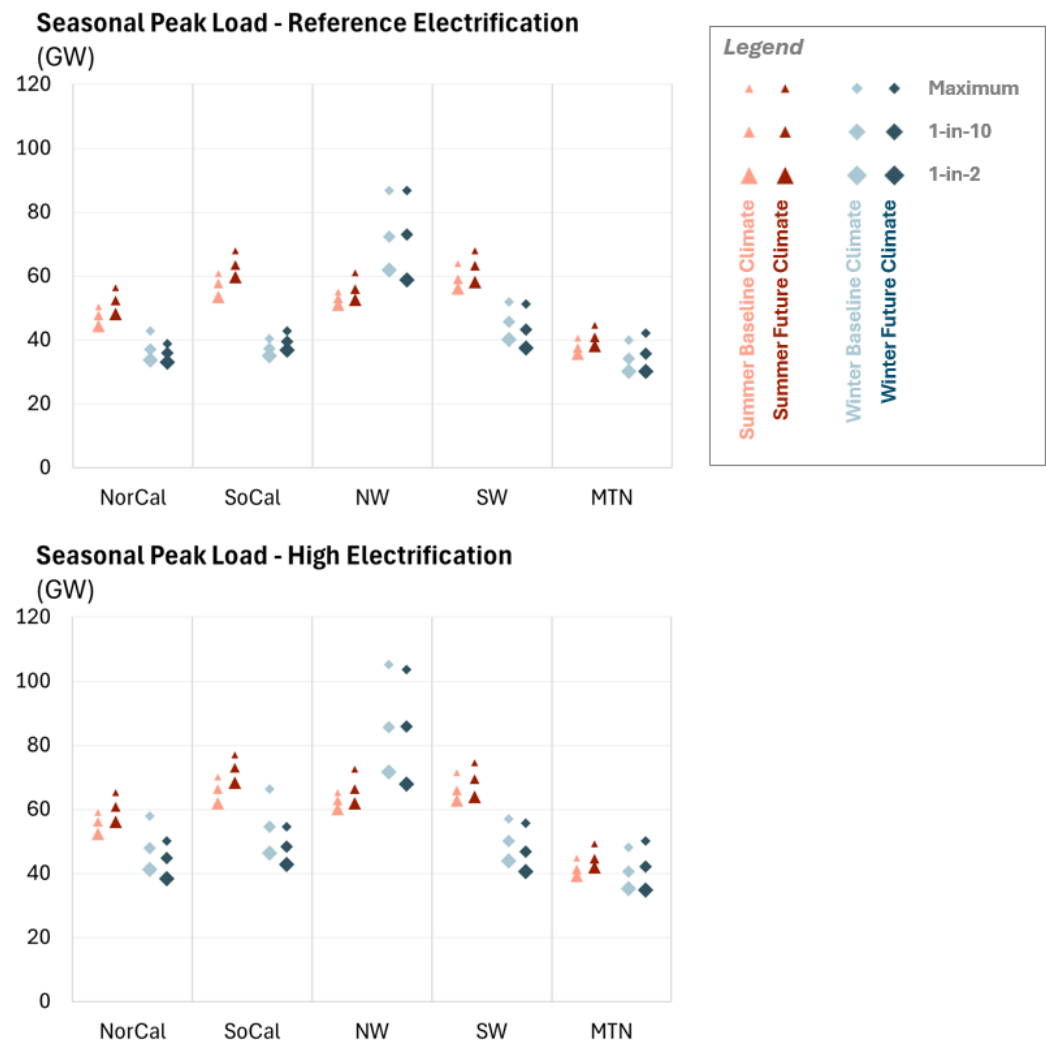
Climate change could potentially have impacts not only on average capacity factors, but also on resource performance under extreme conditions, such as coincident resource droughts when neither solar nor wind resources are available. Analysis performed by collaborating climate scientists under CEC grant EPC-21-037 suggested that the frequency of coincident solar and wind drought may increase under future climate conditions. Their analysis suggested that, although the average change in coincident drought days was relatively small when averaged across broad geographic regions, the analysis revealed a consistent increase in coincident drought days, with a high level of agreement between climate models on more granular regional patterns for coincident drought. Although the magnitude of the effect of coincident renewable resource droughts on the optimal resource portfolio was not specifically quantified in this study, this work drew renewable resource input data from the same datasets, and the effects of any coincident resource drought are implicitly captured in the resulting optimized resource portfolios.

Climate Impacts on Electricity Demand

Figure 8 shows the seasonal 1-in-2, 1-in-10, and maximum peak electricity demands in the year 2045 for summer and winter in each region under Baseline Climate and Future Climate

conditions for both the Reference Electrification and the High Electrification scenarios. The data underlying the figure considers all weather years across all four downscaled GCMs.

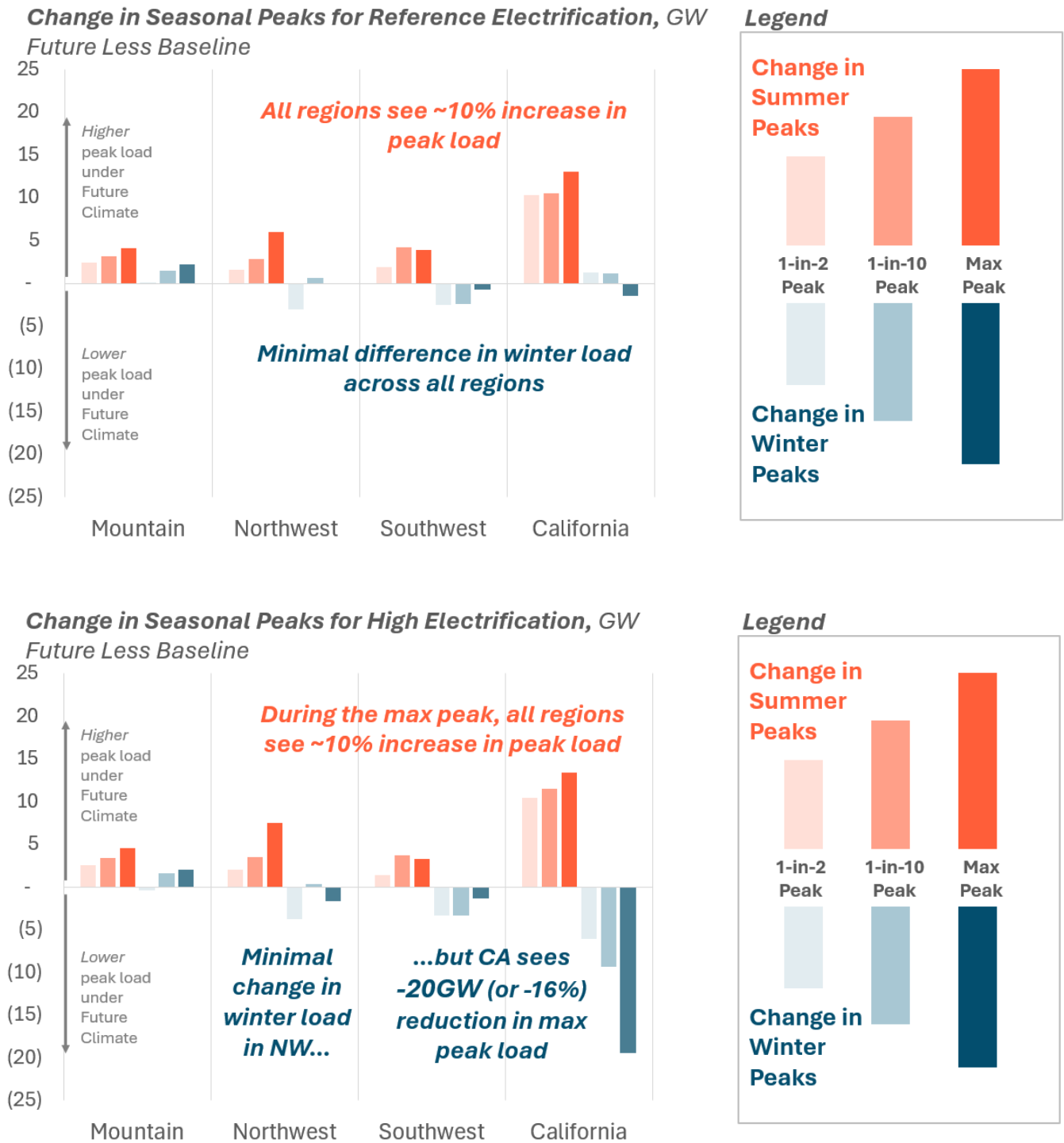
Figure 8. Seasonal Peak Loads by Region in Model Year 2045 for Baseline Climate and Future Climate



Source: Created by Energy and Environmental Economics, Inc.

Figure 9 shows the difference in 1-in-2, 1-in-10, and maximum peak loads in the year 2045 for the summer and winter seasons for Future Climate conditions relative to Baseline Climate conditions in both electrification scenarios. Future climate conditions led to increased summer peak loads across all regions. The winter peak load impacts varied depending on the region. The direction and magnitude of climate impacts on the winter peak loads were heavily dependent on the penetration of electric space heating. In the load forecasts projected for future climate conditions, warmer winters led to a reduction in winter space heating demands but also an increase in winter space cooling demands. The relative magnitude of these two competing effects and the extent to which they offset each other depended on the saturation of electric space heating. Additional details on the climate-informed electricity demand forecasts can be found in the Interim Report for this study.

Figure 9. Change in Seasonal Peak Loads by Region in Model Year 2045 for Baseline Climate and Future Climate



Source: Created by Energy and Environmental Economics, Inc.

CHAPTER 3:

Results and Discussion

This section analyzes the impact of climate change on reliability risks based on LOLP modeling and describes the optimal portfolios developed using LTCE for all regions in the WECC under the different climate and electrification scenarios.

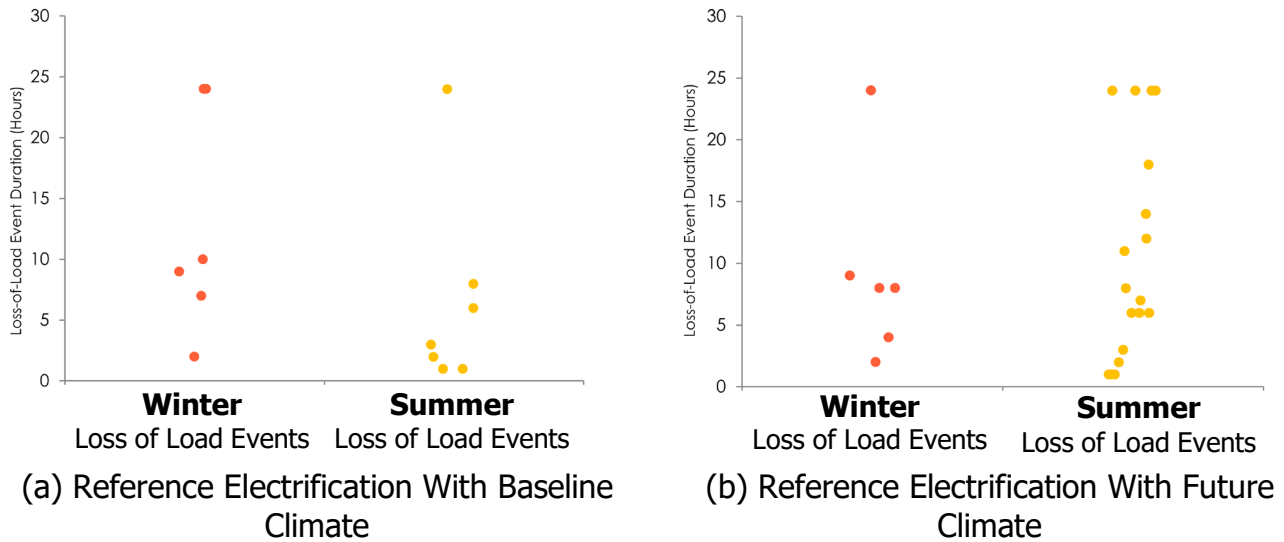
Reliability Challenges Under Future Climate Impacts

The team found that portfolio differences between scenarios were driven by changes in reliability needs with future climate impacts. As described in the “Electric Sector Modeling Methodology” section, the portfolios were calibrated such that each ERM zone would meet the 0.1 LOLE reliability standard using an iterative process. This section focuses on the reliability modeling results for California due to the rich nature of the data, although the portfolio results for other zones were similarly shaped by reliability needs. While all portfolios were designed to meet the 0.1 LOLE standard, the LOLE metric is agnostic to the magnitude, duration, or seasonality of loss of load events. Further analysis into these characteristics provided important information about the evolving nature and possible drivers of loss of load events under Future Climate and also sheds light on why different resources were selected in the portfolios optimized for Baseline Climate and Future Climate conditions under each electrification scenario.

Reference Electrification

For the Reference Electrification cases, the team observed that climate impacts increased the duration of loss of load events, which drove the selection of longer-duration storage resources in the Reference Electrification with Future Climate portfolio in 2045 (Figure 10). In addition, while Southern California’s reliability risks were in summer under both Baseline Climate and Future Climate conditions in the Reference Electrification scenario, Northern California’s reliability risks shifted from winter to summer under Future Climate, which manifests in the decreased frequency of winter loss of load events and the increased frequency of summer loss of load events in Figure 10 (b). These observations are consistent with the team’s findings that Future Climate increases summer peak demand relative to Baseline Climate.

Figure 10. Comparison of Loss of Load Event Durations in California in Model Year 2045 Under Reference Electrification for: (a) Baseline Climate Conditions and (b) Future Climate Conditions

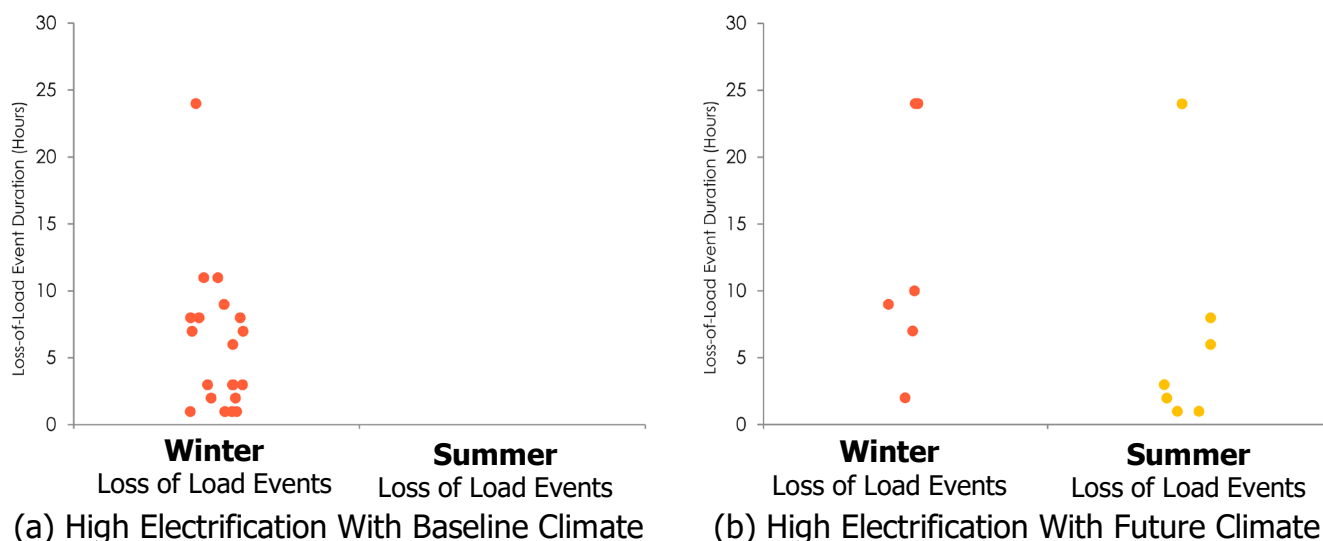


Source: Created by Energy and Environmental Economics, Inc.

High Electrification

In the High Electrification cases, California's 2045 electricity system experienced winter risk only under Baseline Climate conditions; thus, any marginal need for capacity stemmed from the need to reduce winter risk. Under Future Climate, the winter peaks reduced and the summer peaks increased, resulting in the two outcomes seen in Figure 11: (1) a shift from winter-only reliability risk to dual-season reliability risk in California, and (2) a decrease in overall capacity needs due to lower winter peaks (discussed further in the "High Electrification" section). Although summer peaks increased under Future Climate, solar had higher capacity factors in the summer and there was also more surplus energy that could be used to charge storage. Thus, the amount of solar and storage capacity needed to meet the summer peaks under Future Climate was less than the amount needed to meet the winter peaks under Baseline Climate.

Figure 11. Comparison of Loss of Load Event Durations (Hours) in California in Model Year 2045 Under High Electrification for: (a) Baseline Climate Conditions and (b) Future Climate Conditions



Source: Created by Energy and Environmental Economics, Inc.

Change in Resource Portfolios Under Future Climate Impacts

In this section, the team analyzed the optimal portfolios selected by RESOLVE that met the 0.1 LOLE reliability standard as well as clean energy and GHG policy targets. The team compared the portfolios optimized for Baseline Climate and Future Climate conditions for each electrification scenario to assess how incorporating climate-informed load forecasts and renewable generation profiles could influence electricity system planning and investment decisions.

Reference Electrification

In the Reference Electrification cases, optimizing the portfolios under the Future Climate scenario led to a small reduction in the total installed generation and storage capacity by 2045 but to an increased need for firm capacity and longer-duration storage resources relative to Baseline Climate. In California, higher summer peak demands and longer loss of load events increased the need for firm capacity and longer-duration storage by 15 GW in 2045, relative to the optimal portfolio for Reference Electrification with Baseline Climate. Figure 12 shows that optimizing the portfolio for Future Climate conditions decreased the selected capacity of short-duration storage (4-hour) in California by 22 GW, substituting instead with 12 GW longer-duration storage (8+ hours). In addition, optimizing for Future Climate conditions decreased the amount of gas retirements by about 3 GW. RESOLVE did not select any new gas in California for the Reference Electrification cases; unlike other zones, the project team modeled California with a GHG emissions constraint to reflect the state's GHG targets, so RESOLVE tended to select new capacity from non-emitting resources in California in most cases. In Northwest, Southwest, and Mountain, optimizing for Future Climate conditions led to higher

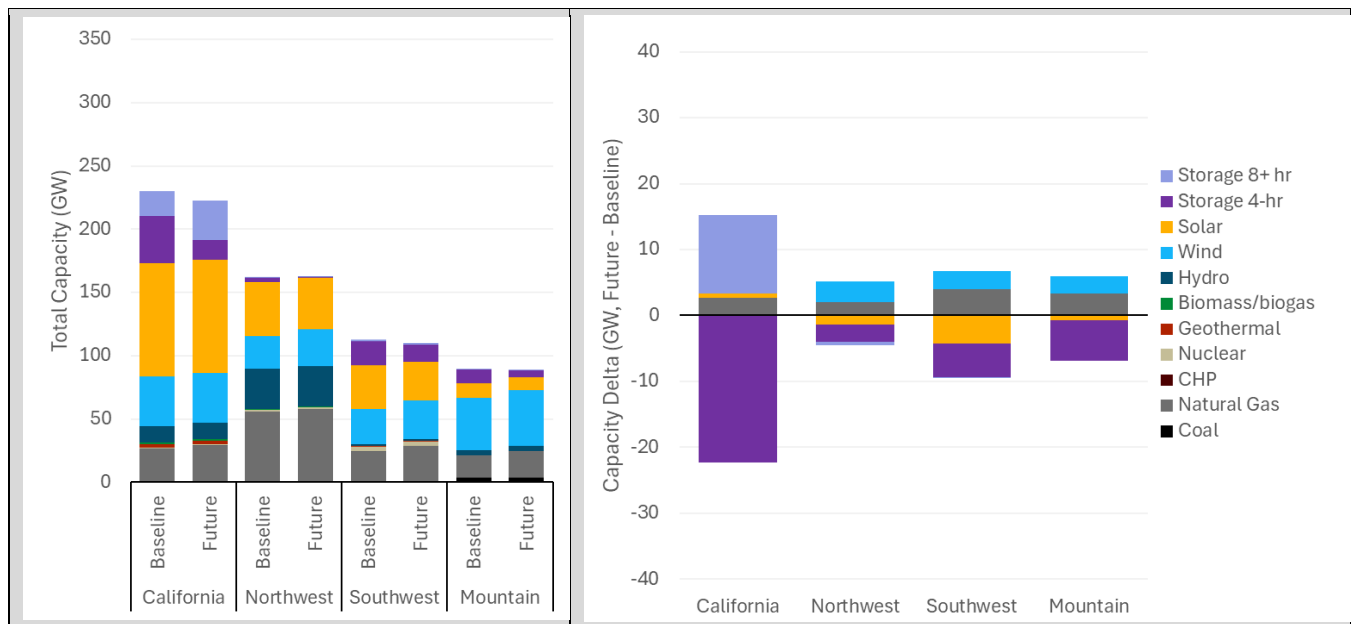
capacity from firm capacity resources and wind and lower capacity from solar and short-duration storage (4-hour). In the Reference Electrification cases, the firm capacity selected for Northwest, Southwest, and Mountain came from gas; while the model had the option to build new geothermal resources, RESOLVE could build gas resources at a lower cost and still meet the clean energy constraints.

While incorporating future climate impacts resulted in some changes in portfolio composition and decreased overall capacity needs in some regions, these portfolio differences were generally small. On the other hand, the degree of uncertainty in other inputs such as load forecasts, cost assumptions, and resource profile shapes was relatively high. For example, in the Reference Electrification cases, optimizing California's portfolio for the Future Climate scenario decreased total capacity needs by about 7 GW (-3.1 percent) relative to the Baseline Climate scenario. By contrast, the next section shows that resource portfolios needed much more capacity to meet the expected load growth under aggressive electrification policies; in California, the High Electrification with Baseline Climate portfolio needed about 70 GW (+30 percent) more capacity relative to the Reference Electrification with Baseline Climate portfolio. This example illustrates that optimizing investment decisions for future climate impacts may not lead to drastically different portfolios and that other inputs and assumptions can have a greater influence on the results. It is worth noting that this result differs from previous studies' findings, which predicted that climate change would increase electricity demand and require a significant buildout of resource capacity.⁴³ The team's findings suggest that diverse resource portfolios optimized to meet clean energy policies, GHG reduction targets, and reliability requirements would likely be resilient to the future impacts of climate change on the Western U.S. In addition, this study's results indicated that firm resources would likely be more valuable to meet reliability needs under future climate conditions and business-as-usual electrification levels.

43 Sathaye, Jayant A., Larry L. Dale, Peter H. Larsen, Gary A. Fitts, Kevin Koy, Sarah M. Lewis, and André Frossard Pereira de Lucena. 2013. "[Estimating impacts of warming temperatures on California's electricity system](https://www.sciencedirect.com/science/article/abs/pii/S0959378012001458)." *Global Environmental Change*, 23 (2): 499-511. <https://www.sciencedirect.com/science/article/abs/pii/S0959378012001458>.

Tarroja, Brian, Felicia Chiang, Amir AghaKouchak, Scott Samuelsen, Shuba V. Raghavan, Max Wei, Kaiyu Sun, and Tianzhen Hong. 2018. "[Translating climate change and heating system electrification impacts on building energy use to future greenhouse gas emissions and electric grid capacity requirements in California](https://www.sciencedirect.com/science/article/abs/pii/S0306261918306962)." *Applied Energy*, 225: 522-534. <https://www.sciencedirect.com/science/article/abs/pii/S0306261918306962>.

Figure 12. Impact of Climate Scenarios on Nameplate Capacity by Region in Model Year 2045 Under Reference Electrification

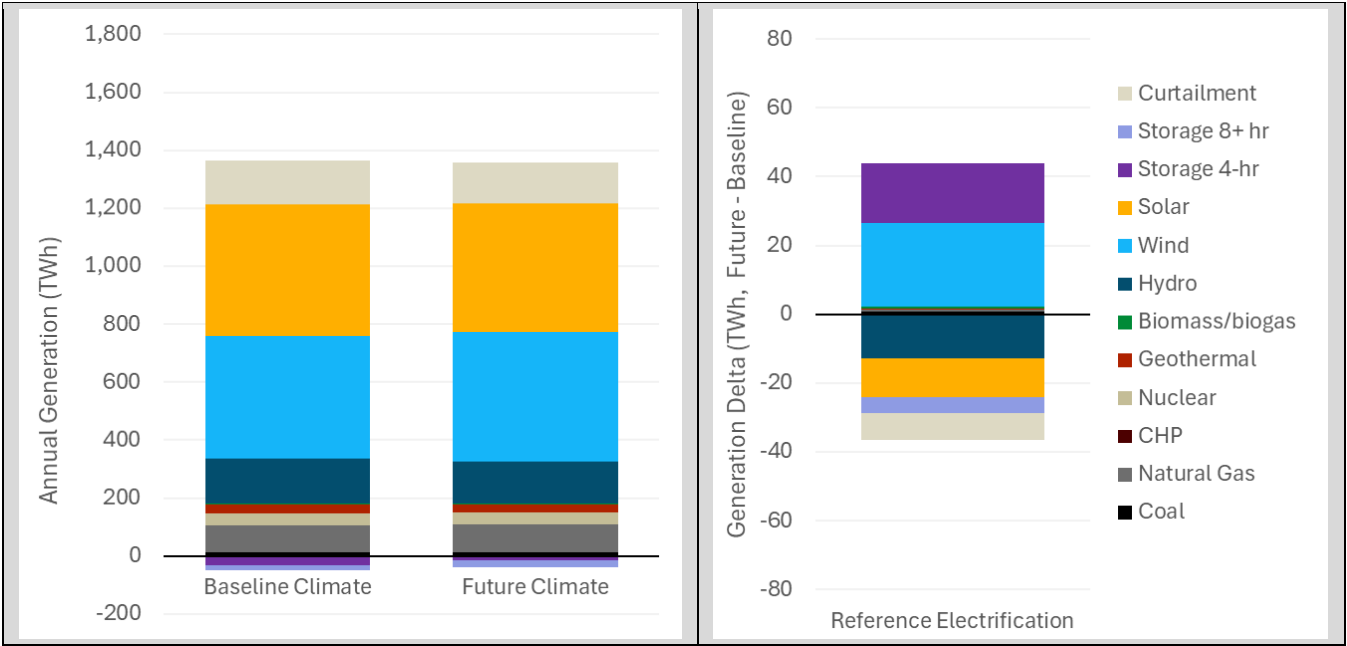


Left: Total Installed Capacity [GW]; Right: Difference in Installed Capacity [GW] Between Future Climate and Baseline Climate

Source: Created by Energy and Environmental Economics, Inc.

Although gas retirements decreased by 3 GW in the Reference Electrification with Future Climate case compared to the Reference Electrification with Baseline Climate case, Figure 13 shows that the total energy generation from gas did not increase at the WECC-wide level because the clean energy standard was a binding constraint in all regions. These results suggest that more firm resources were needed for reliability under future climate conditions and that clean energy goals could still be met by dispatching any carbon-emitting resources less frequently. At the regional level, any increase in energy generation from gas was offset by a decrease in imported energy and storage losses, or vice versa, as shown in Figure 14.

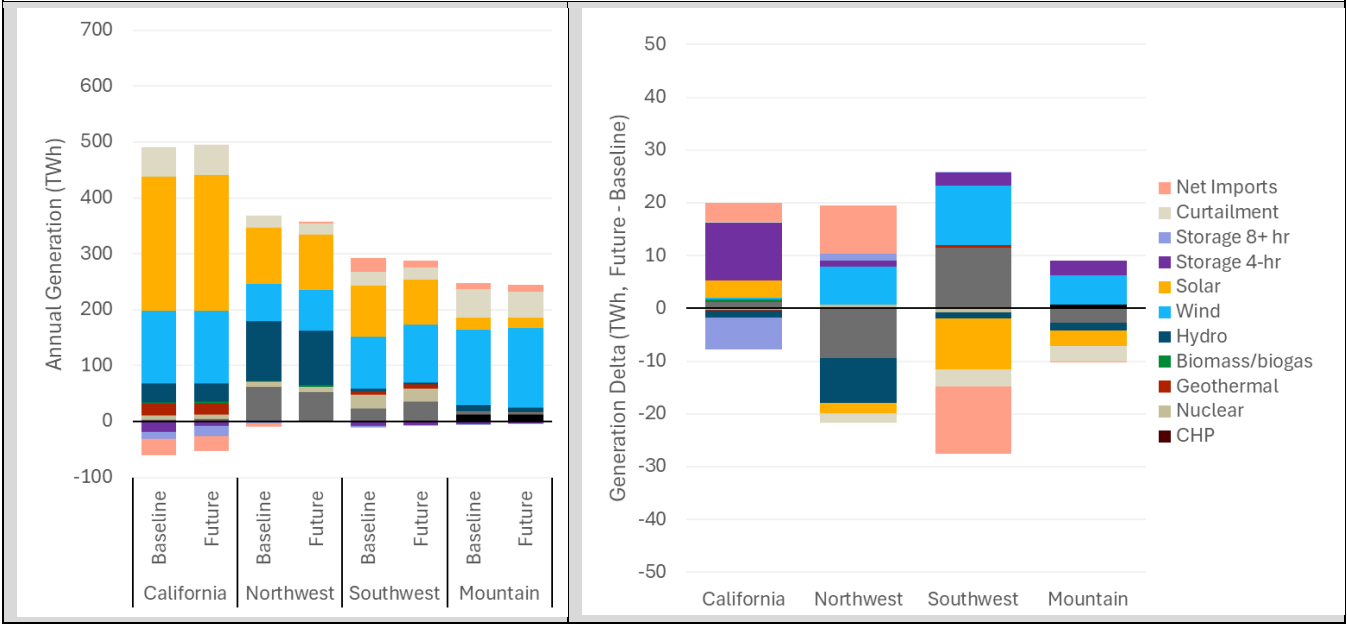
Figure 13. Impact of Climate Scenarios on WECC Generation in Model Year 2045 Under Reference Electrification



Left: Total Annual Generation [in Terawatt-Hours, TWh]; Right: Change in Annual Generation [TWh] Between Future Climate and Baseline Climate

Source: Created by Energy and Environmental Economics, Inc.

Figure 14. Impact of Climate Scenarios on Total Generation by Region in Model Year 2045 Under Reference Scenarios



Left: Total Annual Generation (TWh); Right: Change in Annual Generation (TWh) Between Future Climate and Baseline Climate

Source: Created by Energy and Environmental Economics, Inc.

High Electrification

Unlike the Reference Electrification cases, the portfolio trends in the High Electrification cases varied more by region. In the optimal California portfolios created for the High Electrification cases, electrification amplified the effects of California's warmer winters under Future Climate conditions. As a result, California's optimal portfolio for the High Electrification with Future Climate case had less need for firm resources and lower overall capacity needs than the optimal portfolio for the High Electrification with Baseline Climate case. As seen in Figure 15, warmer winters and a shift from winter to summer reliability risk in California reduced the overall capacity needs by 22 GW (-7.5 percent) and reduced the need for firm capacity and longer-duration storage. Additionally, gas retirements in California increased by 2 GW in the portfolio optimized for future climate conditions, while solar, short-duration storage, and longer-duration storage builds decreased by a combined 23 GW. To meet the GHG constraint, the decrease in solar and storage capacity was offset by a 1.6-GW increase in geothermal capacity and a 1-GW increase in wind capacity in California in the High Electrification with Future Climate case; this new geothermal and wind capacity also contributed to reliability needs, allowing gas retirements to increase.

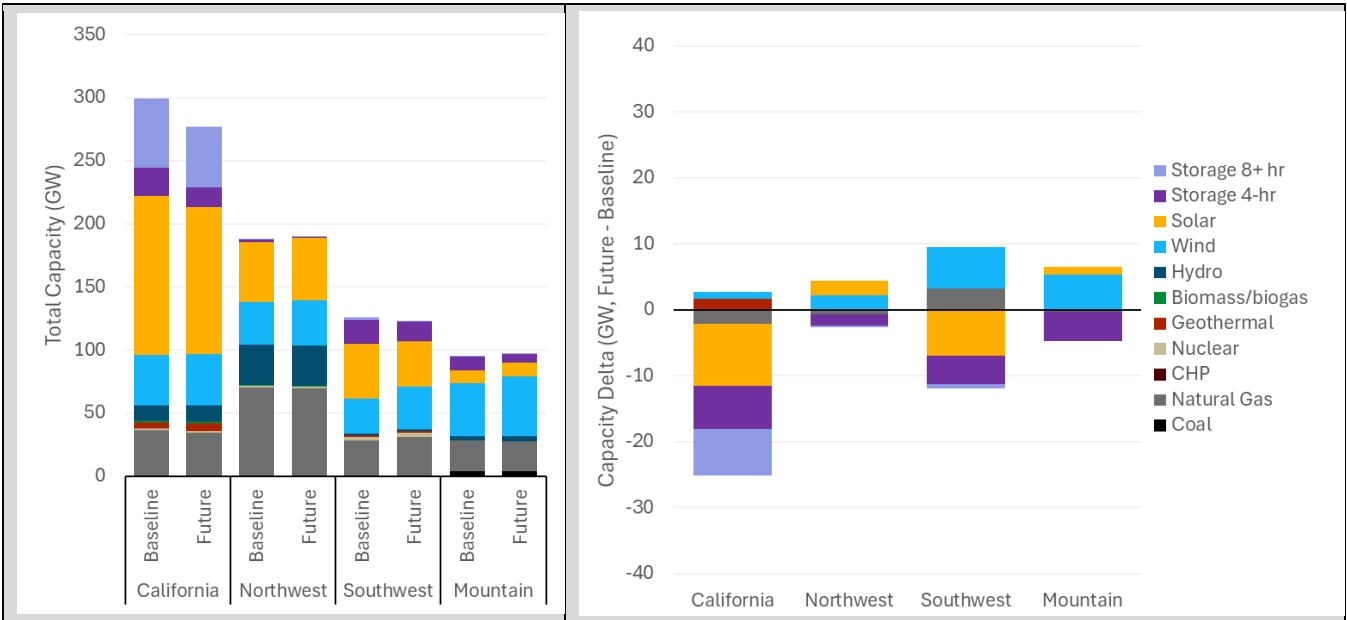
The effect of future climate projections on the High Electrification portfolio optimization was different for other regions. In the Northwest and the Mountain zones, the impact of future climate conditions on winter loads was more muted than the impact observed in California, and the portfolio differences were relatively small. In the Southwest zone, the effect of optimizing for future climate conditions was more similar to the effect in the Reference Electrification cases. While warmer winters led to a slight decrease in winter loads for the Southwest zone, there was a shift towards summer risk in the High Electrification with Future Climate case compared to the High Electrification with Baseline Climate case, as summer peak demands were projected to increase under future climate conditions. This drove a need for more firm capacity from gas, which reduced the need for short-duration storage to maintain reliability and, by extension, for solar to charge the storage. Wind was then substituted for solar to meet the clean energy standard.

Due to the large amount of uncertainty, these results should not be interpreted as predictions of future portfolios but rather indications that, when combined with aggressive electrification, regions with a high penetration of electrified heating that experience winter warming under future climate conditions may need less firm capacity and less longer-duration storage. Other regions with lower winter heating demands experienced reliability risk mostly in the summer, which was exacerbated by future climate impacts. These regions tended to need more firm capacity under Future Climate. Furthermore, the team's results suggest that, contrary to previous studies,⁴⁴ overall resource capacity needs may even decrease for some regions in a climate-impacted future assuming aggressive electrification policies. Optimizing California's portfolio for the High Electrification with Future Climate scenario decreased total capacity needs by 22 GW (-7.5 percent) relative to the High Electrification with Baseline Climate scenario. Nevertheless, incorporating future climate impacts in the High Electrification cases had a smaller effect on the optimized resource portfolios than the electrification assumptions themselves. For example, California needed about 70 GW (+30 percent) more capacity in the

⁴⁴ Ibid.

High Electrification with Baseline Climate scenario relative to the Reference Electrification with Baseline Climate scenario.

Figure 15. Impact of Climate Scenarios on Total Nameplate Capacity by Region in Model Year 2045 Under High Electrification

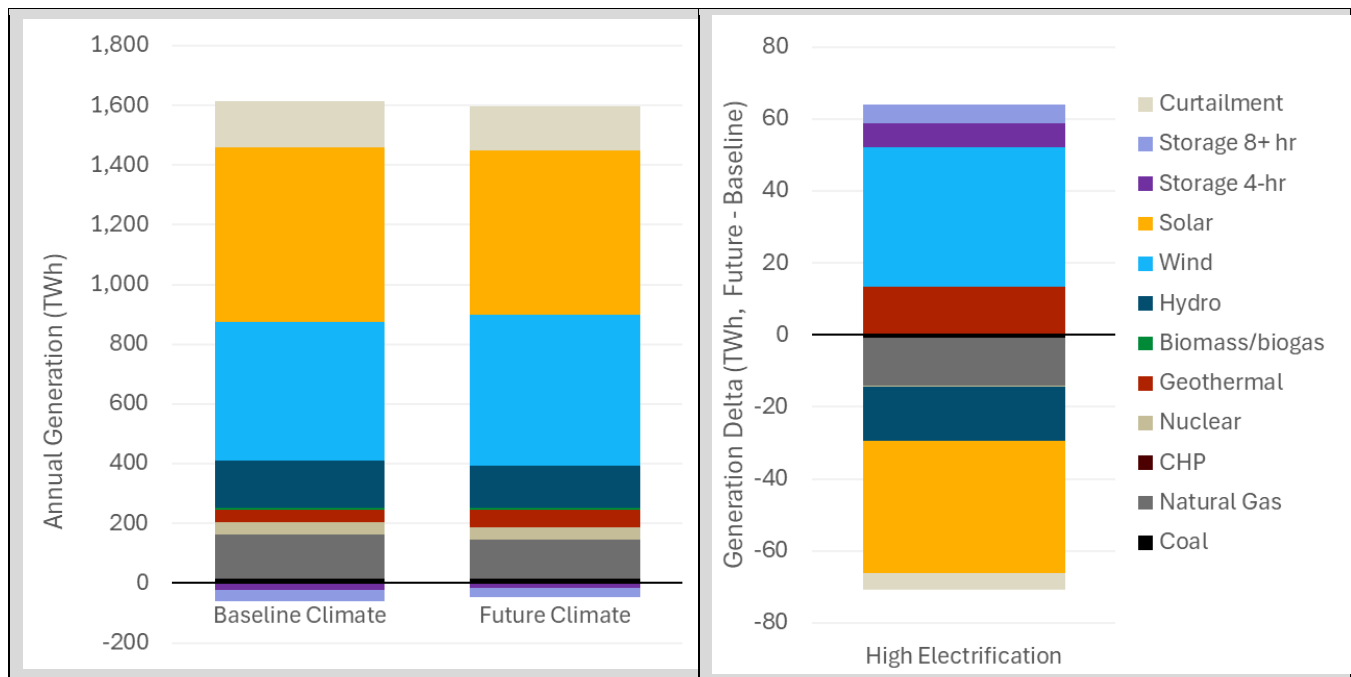


Left: Total Installed Capacity (GW); Right: Difference in Installed Capacity (GW) Between Future Climate and Baseline Climate

Source: Created by Energy and Environmental Economics, Inc.

Figure 16 shows that incorporating future climate impacts did not increase the total energy generation from gas in the High Electrification cases at the WECC-wide level because the clean energy standard was a binding constraint in all regions. In fact, total energy generation from gas at the WECC-wide level was lower in the High Electrification with Future Climate case than the High Electrification with Baseline Climate case. Similar trends were observed in individual regions except for the Southwest, where the increase in energy generation from gas was offset by a decrease in imported energy (Figure 17).

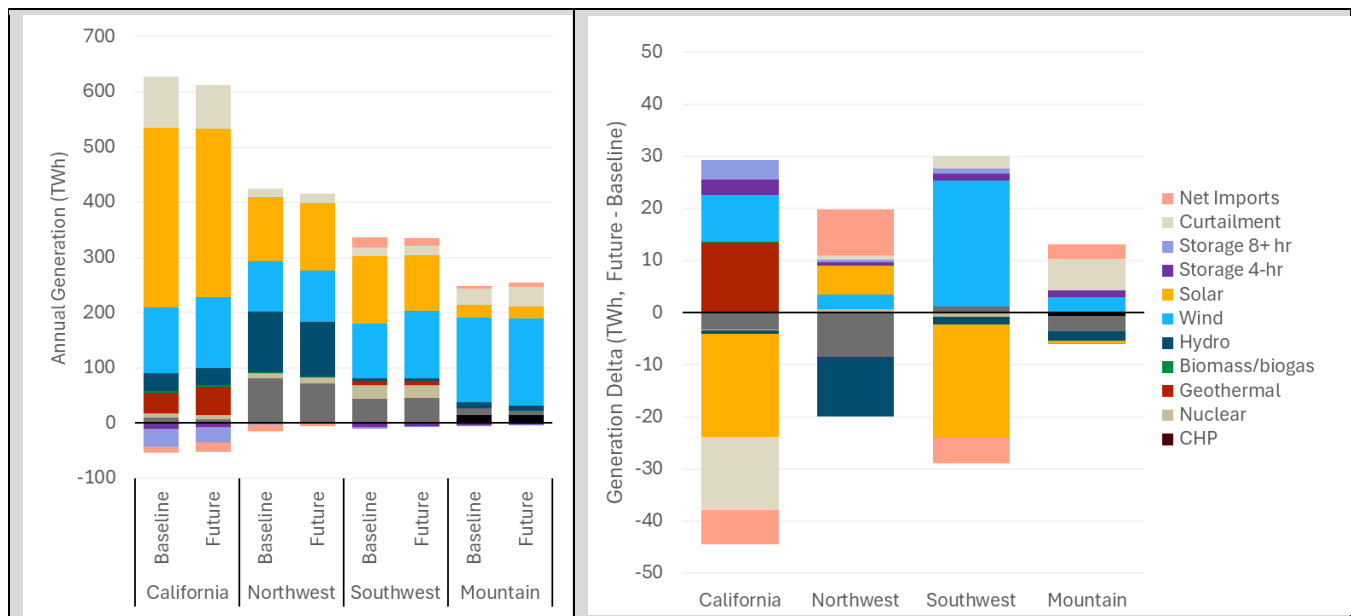
Figure 16. Impact of Climate Scenarios on WECC Total Generation in Model Year 2045 Under High Electrification



Left: Total Annual Generation (TWh); Right: Change in Annual Generation (TWh) Between Future Climate and Baseline Climate

Source: Created by Energy and Environmental Economics, Inc.

Figure 17. Impact of Climate Scenarios on Total Generation by Region in Model Year 2045 Under High Electrification



Left: Total Annual Generation (TWh); Right: Change in Annual Generation (TWh) Between Future Climate and Baseline Climate

Source: Created by Energy and Environmental Economics, Inc.

Affordability Implications

The portfolio-driven cost and affordability impacts of climate change will be complex and convoluted with other factors including changing electricity demand, load patterns, and future climate change adaptation strategies. While an in-depth quantification of all of the potential cost impacts of climate change — which could be significant across many areas of society — was beyond the scope of this study, the team did quantify directional impacts in costs of resource portfolios associated with the modeled scenarios.

Modeled portfolio costs under each scenario are not reported due to the wide uncertainty ranges and simplifications made in the RESOLVE model to manage run time and problem size. While the total investment and operational costs for generation and storage were modeled, transmission and distribution constraints (for both electricity and natural gas) were simplified to ensure that the model could computationally converge on a solution within a reasonable amount of time. As a result, certain costs related to transmission and distribution upgrades were not directly captured in the model. Similarly, system “hardening” costs related to climate impacts were not included in the portfolio optimization.

With those caveats in mind, the team discusses here the potential directional impacts of climate change on electricity system costs and affordability implications for ratepayers based on the modeling results. Under the Reference Electrification scenario, climate impacts appeared to *increase* the resource portfolio costs due to higher capacity needs under Future Climate relative to Baseline Climate, and there is a greater reliance on emerging technologies such as longer-duration energy storage, which may also increase the portfolio cost and the technology risk. In contrast, the High Electrification scenario illustrated a case where the combination of electrification and climate impacts could *decrease* the resource portfolio costs, due to lower capacity needs in the Future Climate scenario relative to the Baseline Climate scenario.

Overall, the magnitude of the Future Climate impacts on energy demand and resource portfolios under the conditions tested in this study suggest that climate change appears unlikely to significantly increase or decrease total utility resource portfolio costs. Furthermore, the modeled changes to resource portfolio costs would have a relatively small impact on future consumer electricity bills relative to other factors that have been observed to date (for example, wildfire mitigation costs).

However, these results suggest a potential for increased seasonal volatility in utility bills, given that Future Climate may lead to an increase in summer energy demands due to increased air conditioning usage, which will be very temperature dependent, and to a decrease in winter energy demands due to decreased space heating usage relative to Baseline Climate. The decrease in winter energy demands for space heating was observed across both heat pumps and natural gas furnaces, suggesting potential winter-time bill savings for both electricity and natural gas.

An important caveat to note is that future policy achievement is highly uncertain, adding difficulty to the interpretation of these results. The 2045 levels of building electrification

adoption may fall anywhere between the two scenarios modeled, or they could fall outside the range considered by these scenarios.

Future research using California's downscaled climate data could provide insight into how the most vulnerable residents will be impacted by climate change. For example, many of California's most energy-burdened residents are low-income households, living in hot, inland climates that may experience more extreme heat waves in the future. Coastal residents who do not currently have air conditioning are also more likely to need AC in the future, which will result in both higher upfront costs to install AC equipment, as well as higher summertime energy bills. Low-income residents are also less likely to be adopters of energy efficiency measures and high-efficiency electrified end-uses, meaning they will continue to use less-efficient electric or gas devices, increasing their utility bills. An evaluation of solutions to protect low-income residents from the impacts of climate change was not the focus of this study but could be an important area for future research.

CHAPTER 4:

Conclusion

This study created a climate-informed electric energy and peak demand forecast from 2025 to mid-century (2045) for California, designed to meet the state’s decarbonization goals, as well as forecasts for the other regions in the WECC. In addition, this study produced optimized electricity system portfolios that met clean energy goals, California’s GHG reduction target, and reliability standards with and without the future projected impacts of climate change. Below, the team summarizes the key takeaways from the study and lessons learned.

Summary of Key Takeaways

- Climate change is expected to lead to hotter summers and to peak load growth in summer months. Climate impacts in the winter are less certain, but they appear to trend towards warmer winters, reducing wintertime heating energy demands and, in some cases, increasing winter air conditioning needs. As a result, **both summer and winter demand impacts should be considered in order to understand grid impacts**. Climate-informed load forecasts show temperature-driven load growth from increased air conditioning usage in the summer across all regions and electrification scenarios, whereas impacts to winter peak loads are more variable across downscaled GCMs, regions, and electric space heating adoption levels. In the High Electrification cases that assumed high levels of electric space heating, the resource portfolios were more sensitive to climate impacts on the winter peak loads and winter reliability risk.
- **The changes in optimized resource portfolios from incorporating future climate projections were strongly dependent on electrification levels and seasonal reliability risk**. In the Reference Electrification cases, climate impacts increased summer peak demand and extended the duration of loss of load events in California, leading to a greater need for longer-duration energy resources. The High Electrification cases yielded portfolios with characteristic differences relative to the Reference Electrification cases due to the substantially higher levels of electrification across all sectors regardless of climate, as well as the high levels of electrified space heating which increased the weather dependence of the loads. In some regions including California, warmer winters shifted reliability risk toward summer periods. As a result, the overall need for capacity — including firm, variable, and storage resources — declined under future climate conditions, highlighting how electrification levels can influence grid resource needs and expected climate impacts.
- **Under the range of conditions tested, differences between electrification scenario assumptions had a greater impact on electricity demand and resource portfolios relative to climate impacts**. Although incorporating climate impacts did yield changes in resource portfolio compositions, these differences were relatively modest relative to the portfolio changes that resulted from different assumptions around electrification. This demonstrates the need to contextualize climate impacts within the realm of other modeling uncertainties. The next two decades will

require a significant buildout of new grid capacity resources to serve growing electricity demand and to meet clean energy and GHG reduction goals. This buildout will happen in conjunction with a changing climate, including more uncertainty and variability in future weather patterns. In contrast to previous studies which predicted that maintaining a reliable electricity system in a climate-impacted future would require significant resource buildout,⁴⁵ this study found that overall capacity needs did not substantially increase after optimizing portfolios for future climate conditions under both the business-as-usual and the aggressive electrification scenarios.

- **The team’s findings suggest that diverse resource portfolios — including renewables, storage of varying durations, and firm capacity resources like gas and geothermal — that are optimized to reliably meet clean energy and climate policies will also contribute to resilience to the future impacts of climate change on the Western U.S.** When previous studies were conducted in the 2010s, the grid had a less diverse mix of generation resources, since natural gas generation provided the majority of both energy and capacity. As the climate changes, continuing to develop a diverse mix of resources will be critical to both reducing GHG emissions and ensuring reliability in both summer and winter months, when critical stress periods on the grid are expected to increase in duration from several hours to 24 hours or more.

Lessons Learned

Integrating climate data into electricity system planning is necessary to plan for risks introduced or exacerbated by climate change. However, the data produced by GCMs is a new input into industry standard planning tools, and the team grappled with many questions related to interpretation of differences between climate datasets, appropriate usage of and assumptions for climate data, and consistency between climate data and industry-standard datasets (for example, California wind capacity factors). These challenges highlighted the need for close coordination between planners and climate scientists, knowledge sharing, and the development of a shared language and methodological framework. While this project serves as a useful research effort, the development of climate-informed planning methods fit for making investment decisions will require additional work to standardize methods, clarify appropriate applications, and establish governance around how climate data is used and how often it is updated. Additionally, the choice of methods and modeling tools used for electricity system modeling plays an essential role in the ultimate results (for example, the feedback loop between resource adequacy modeling and long-term capacity expansion modeling employed in

45 Sathaye, Jayant A., Larry L. Dale, Peter H. Larsen, Gary A. Fitts, Kevin Koy, Sarah M. Lewis, and André Frossard Pereira de Lucena. 2013. "[Estimating impacts of warming temperatures on California's electricity system](https://www.sciencedirect.com/science/article/abs/pii/S0959378012001458)." *Global Environmental Change*, 23 (2): 499-511. <https://www.sciencedirect.com/science/article/abs/pii/S0959378012001458>.

Tarroja, Brian, Felicia Chiang, Amir AghaKouchak, Scott Samuelson, Shuba V. Raghavan, Max Wei, Kaiyu Sun, and Tianzhen Hong. 2018. "[Translating climate change and heating system electrification impacts on building energy use to future greenhouse gas emissions and electric grid capacity requirements in California](https://www.sciencedirect.com/science/article/abs/pii/S0306261918306962)." *Applied Energy*, 225: 522-534. <https://www.sciencedirect.com/science/article/abs/pii/S0306261918306962>.

this work). The team learned several lessons over the course of this study that can help guide future research in this area.

- Incorporating climate-informed data introduces another layer of uncertainty to electricity sector planning.
 - There is significant uncertainty in climate-informed data. Not only will the emissions trajectory be highly dependent on technological developments, economic growth, and policy adoption and implementation, but different downscaled GCMs predict substantially different climate outcomes (for example, changes in temperature, precipitation) for the same emissions trajectory. Modelers will need to make decisions around which models to use and how to appropriately weight them.
 - This study used four downscaled GCMs with the same SSP, but there was still significant inter-model variability in terms of weather-dependent loads, wind capacity factor profiles, and hydroelectric energy budgets. This inter-model variability sometimes exceeded the underlying climate signal. For example, in the case of California onshore wind, the difference in average capacity factors between Baseline Climate conditions and Future Climate conditions was similar in magnitude to the difference between the average capacity factor for TAI-ESM1 under Future Climate conditions and the average capacity factor for the other three GCMs under Future Climate conditions.
 - In this study, the team combined the climate data into one dataset per climate and electrification scenario for electricity system modeling, with 10 representative days from each downscaled GCM — treating the four selected GCMs as equally plausible climate futures. However, additional insights may be gained from alternative approaches to the selection and representation of climate data, and the team recommends this as an area for future research.
- **Ingesting climate projections into standard electricity system planning models requires careful translation to transform the outputs of high-resolution climate projections into usable model inputs.**
 - There are trade-offs in this translation process that should be considered when determining which methodology to use. For example, trade-offs between incorporating the full spatiotemporal granularity of the data from GCM historical simulations and future projections and the computational time required to produce hourly load forecasts and to optimize the electricity resource portfolio required the team to develop approaches to sampling GCM climate data that would limit computational time while capturing the key features of the datasets. In terms of capacity expansion modeling, the team optimized investment and operational decisions for only one model year (2045) and used only four weather years to represent weather variability in the ERM constraint. As found in several test cases, including more data caused RESOLVE to exceed its memory and run time limits. While more computational power could be directed to this problem in

future research, the benefits of added data computation and precision should be weighed against the potential gains in accuracy and model outcomes, given the many sources of future uncertainty in long-term climate models and electricity system modeling.

- **The feedback loop between resource adequacy modeling and capacity expansion modeling played a pivotal role in defining final resource portfolio results.**
 - The iterative process between RECAP and the long-term capacity expansion modeling (RESOLVE) represented an important modeling step to adequately capture the impacts of climate change on the grid. Specifically, the iterative process used to calibrate the ERM inputs for LTCE and to confirm, using LOLP modeling, that the portfolio generated by LTCE met the 0.1 LOLE standard ultimately defined the final portfolio and reliability results for the four cases considered in this study. (Note that, while this method applied an ERM approach, an ELCC-based approach could also have been applied to capture the impacts of climate on reliability periods). Nearly 200 different portfolios were developed over the course of the study, and the majority of LTCE model runs were conducted to calibrate the ERM to ensure that the diverse mix of resources across the WECC met the same 0.1 LOLE reliability standard under different climate conditions. While most LOLP modeling runs were performed to measure reliability, each run provided insights to the features and characteristics of each resource's ability to contribute to reliability. As the ERM constraints were refined, the team observed significant changes to the size and composition of portfolios as well as to the nature of reliability events, leading the team to conclude that reliability requirements were a significant driver of the results.
- **Coordination will be needed between climate scientists, energy system modelers, and policymakers to ensure that climate-informed electricity system planning is meaningful and fit-for-purpose in driving investment decisions.**
 - Despite the uncertainties introduced when incorporating climate data and the transformation required to prepare the data for use in the electricity system planning models, the results can still provide useful insights about the impacts of climate change on the electricity system and the implications for developing an optimal portfolio that meets policy and reliability targets. However, understanding which results are robust in spite of the uncertainties requires close coordination between climate scientists and electricity system planners.
 - Collaboration between project partners was essential in this project. For example, Eagle Rock Analytics guided E3's usage of climate data, such as switching from ERA5 to historical simulations produced by the other GCMs for the Baseline Climate cases and including at least 30 weather years for the full-weather year datasets used for both the Baseline Climate and the Future Climate cases to capture long-term weather patterns (for example, El Niño and La Niña).

These experiences demonstrated how cross-disciplinary collaboration can drive more meaningful results and would also be essential to inform better investment decisions in a real-world planning exercise.

- California has led a significant effort to develop and invest in climate-informed weather data. As a state, California is only starting to scratch the surface on the many ways that this data can be applied not just in research but in long-term planning and investment tools. This research demonstrates some provocative insights into how a changing future climate is likely to impact the least-cost resource portfolios across the West, while maintaining grid reliability and reducing total GHG emissions. Further exploration using these climate-informed data sets will help to validate or dispute these initial research findings and will help standardize methods and approaches towards using this data in a planning context.

GLOSSARY AND LIST OF ACRONYMS

Term	Definition
BAAQMD	Bay Area Air Quality Management District
BAU	business-as-usual
CAISO	California Independent System Operator
CARB	California Air Resources Board
CAVA	Climate Adaptation Vulnerability Assessment
CEC	California Energy Commission
CES	clean energy standard
CMIP5	Coupled Model Intercomparison Project Phase 5
CMIP6	Coupled Model Intercomparison Project Phase 6
COP	coefficient of performance
CPUC	California Public Utilities Commission
E3	Energy and Environmental Economics, Inc.
EIA	U.S. Energy Information Administration
EIA SEDS	EIA's State Energy Data System
ELCC	Effective Load Carrying Capacity
EPIC	Electric Program Investment Charge
ERA5	European Centre for Medium-Range Weather Forecasts Reanalysis v5
ERM	Energy Reserve Margin
EUE	expected unserved energy
EV	electric vehicle
GCM	global climate model
GHG	greenhouse gas
GW	gigawatts
GWL	Global Warming Level
HDV	Heavy-Duty Vehicle
HEC	Hourly Expected Capacity
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Plan
LBNL	Lawrence Berkeley National Laboratory
km	kilometer

Term	Definition
LDV	Light-Duty Vehicle
LOCA2	Localized Constructed Analogs version 2
LOLE	loss of load expectation
LOLP	loss of load probability
LSE	load serving entity
LTCE	long-term capacity expansion
MMT	million metric tons
MW	megawatts
PRM	Planning Reserve Margin
RAMP	Risk Assessment Mitigation Phase
RECAP	Renewable Energy Capacity Planning Model
RESOLVE	E3's long-term capacity expansion model
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SSP	Shared Socioeconomic Pathway
TAC	Technical Advisory Committee
TWh	terawatt-hours
WECC	Western Electricity Coordinating Council
WRF	Weather Research and Forecasting

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Project Deliverables

Deliverable	Description	Data location
Final Report	Current document summarizing study	CEC Publications website
Interim Report	Interim report focused on climate-informed load forecasts, titled <i>Climate-Informed Load Forecasting for California</i>	Available upon request from CEC (peer reviewed as part of California's Fifth Climate Assessment)
Shareable Data Products	Summary of climate impacts on load forecasting data spreadsheet	Available upon request from CEC
	Summary of climate impacts on capacity expansion and reliability data spreadsheet	Available upon request from CEC
	RESOLVE modeling toolkit, documentation and user guide	Available upon request from CEC
	RECAP modeling toolkit, documentation and user guide	Available upon request from CEC
	Climate-informed hourly load forecasts by scenario	Example scenario available upon request from CEC (for complete suite of scenarios, please inquire)
	Summary of bill impacts and affordability metrics for representative customers spreadsheet	Available upon request from CEC



**CALIFORNIA
ENERGY COMMISSION**



ENERGY RESEARCH AND DEVELOPMENT DIVISION

APPENDIX A: PATHWAYS Inputs & Assumptions

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APPENDIX A:

PATHWAYS Inputs & Assumptions

This appendix describes the inputs and assumptions used to generate annual loads using E3's PATHWAYS model.

Electrification Scenario Assumptions

Policy assumptions for each electrification scenario determined how much electric load growth occurs from the base year through 2050. Two different electrification scenarios were modeled for California regions, a **Reference Electrification** scenario and a **High Electrification** scenario. For California, the Reference Electrification scenario included current policy measures and trends as of 2024. The High Electrification scenario added policy measures, incremental to the Reference Electrification scenario, that align with the 2022 CARB Scoping Plan to achieve Net Zero emissions by 2045.⁴⁶ Policy assumptions for California are summarized in Table A-1.

⁴⁶ California Air Resources Board. 2022. "[2022 Scoping Plan Documents](https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents)." <https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents>.

Table A-1 California PATHWAYS Electrification Scenario Assumptions

Sector	Reference Electrification Scenario	High Electrification Scenario <i>(Incremental measures relative to reference scenario)</i>
Buildings	Title 20⁴⁷: Screw-base CFL bulbs will be phased out by 2024, pin-base CFL and fluorescent tubes by 2025 Title 24⁴⁸: 100% new construction electric water heating and space heating starting in 2026 BAAQMD Zero-NOx standards⁴⁹: 100% replacement on burnout for BAAQMD by: 2027 for water heating; 2029 for space heating SCAQMD Zero-NOx standards⁵⁰: 100% replacement on burnout for water heating by 2029 Historical trends for heat pump space heating adoption by state Heat pump water heater “Low” scenario from EPA analysis Energy efficiency: Aligned with national device standards and energy efficiency trends over time	New construction: all electric appliances beginning in: 2026 (residential); 2027 (commercial) Existing residential buildings: 80% of appliance sales are electric by 2030 and 100% by 2035 Existing commercial buildings: 80% of appliance sales are electric by 2030 and 100% by 2045 Heat pump target: 6 million heat pumps installed statewide by 2030 All-electric homes target: 3 million all-electric homes by 2030 and 7 million by 2035 Energy efficiency: Aligned with national device standards and energy efficiency trends over time

47 California Energy Commission. 2021. [California Code of Regulations Title 20. Public Utilities and Energy: Division 2. State Energy Resources Conservation and Development Commission](https://www.energy.ca.gov/publications/2021/california-code-regulations-title-20-public-utilities-and-energy-division-2). July 26. <https://www.energy.ca.gov/publications/2021/california-code-regulations-title-20-public-utilities-and-energy-division-2>.

48 California Department of General Services Building Standards Commission. 2025. [California Building Standards Code](https://www.dgs.ca.gov/bsc/codes). <https://www.dgs.ca.gov/bsc/codes>.

49 Bay Area Air District. [Rules 9-4 and 9-6 Building Appliances](https://www.baaqmd.gov/rules-and-compliance/rule-development/building-appliances). <https://www.baaqmd.gov/rules-and-compliance/rule-development/building-appliances>.

50 South Coast AQMD. 2024. [Proposed Amended Rule 1146.2](https://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/rule-1146-2). <https://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/rule-1146-2>.

Sector	Reference Electrification Scenario	High Electrification Scenario <i>(Incremental measures relative to reference scenario)</i>
Transportation	Advanced Clean Cars II (ACC II)⁵¹ Vehicle miles traveled (VMT) per capita reduced for light-duty vehicles 4% below 2019 levels by 2045, aligned with Mobile Source Strategy (MSS) BAU scenario⁵² Advanced Clean Trucks (ACT)⁵³ Advanced Clean Fleets (ACF)⁵⁴	100% of medium- and heavy-duty vehicle sales are zero-emissions vehicles (ZEVs) by 2040 SB375⁵⁵: VMT per capita for light-duty vehicles reduced 25% below 2019 levels by 2030 and 30% below 2019 levels by 2045 Aviation: AB197⁵⁶: 20% of aviation fuel demand is met by electricity (batteries) or hydrogen (fuel cells) in 2045. Sustainable aviation fuel meets the rest of aviation demand that has not already transitioned to hydrogen or batteries Ocean-going vessels (OGVs): 2020 OGV At-Berth regulation fully implemented, with most OGVs utilizing shore power by 2027. 25% of OGVs utilize hydrogen fuel cell electric technology by 2045 Rail: 100% of passenger and other locomotive sales are ZEV by 2030. 100% of line haul locomotive sales are ZEV by 2035. Line haul and passenger rail rely primarily on hydrogen fuel cell technology, and others primarily use electricity

51 California Air Resources Board. "[Advanced Clean Cars](https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program/advanced-clean-cars-ii)." <https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program/advanced-clean-cars-ii>.

52 California Air Resources Board. 2021. "[2020 Mobile Source Strategy](https://ww2.arb.ca.gov/resources/documents/2020-mobile-source-strategy#:~:text=The%20actions%20contained%20in%20the,growth%20in%20the%20mobile%20sector)." <https://ww2.arb.ca.gov/resources/documents/2020-mobile-source-strategy#:~:text=The%20actions%20contained%20in%20the,growth%20in%20the%20mobile%20sector>.

53 California Air Resources Board. "[Advanced Clean Trucks](https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks)." <https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks>.

55 California Air Resources Board. "[SB 375 Regional Targets](https://ww2.arb.ca.gov/our-work/programs/sustainable-communities-program/sb-375-regional-targets)." <https://ww2.arb.ca.gov/our-work/programs/sustainable-communities-program/sb-375-regional-targets>.

56 California Air Resources Board. 2022. [Appendix C: AB 197 Measure Analysis](https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-appendix-c-ab-197-measure-analysis.pdf). November. <https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-appendix-c-ab-197-measure-analysis.pdf>.

Sector	Reference Electrification Scenario	High Electrification Scenario <i>(Incremental measures relative to reference scenario)</i>
Industry	Aligned with current trends ⁵⁷	Agriculture and construction: 25% of energy demand electrified by 2030 and 75% by 2045 Food Production: 7.5% of energy demand electrified by 2030 and 75% by 2045 Chemical and paper: electrify 0% of boilers by 2030 and 100% by 2045. Hydrogen for 25% of process heat by 2035 and 100% by 2045. Electrify 100% of other energy demand by 2045 Petroleum refining energy demand ramped down in line with in-state petroleum demand. CCS on majority of operations by 2030, beginning in 2028 Oil & gas extraction ramped down to 30% below 2019 levels by 2030 and 40% by 2045 Stone, Glass, and Cement: CCS on 40% of operations by 2035 and all facilities by 2045 Other Industry: 0% of energy demand electrified by 2030 and 50% by 2045
Data centers	E3 internal forecast on data center growth over time (loads assume 79% annual capacity factors based on CEC analysis of SVP data centers)	E3 internal forecast on data center growth over time (loads assume 79% annual capacity factors based on CEC analysis of SVP data centers)

56 California Air Resources Board. 2022. [Appendix C: AB 197 Measure Analysis](https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-appendix-c-ab-197-measure-analysis.pdf). November. <https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-appendix-c-ab-197-measure-analysis.pdf>.

57 U.S. Energy Information Administration. 2023. [Annual Energy Outlook 2023](https://www.eia.gov/outlooks/archive/aeo23/). March 16. <https://www.eia.gov/outlooks/archive/aeo23/>.

Each state in the Western U.S. was also modeled. In the Reference Electrification scenario, the other states have their own Reference inputs based on current policies and trends as of 2024. In the High Electrification scenario, states that have enacted their own Net Zero policies have a set of incremental measures, while the remaining states are modeled with the Reference Scenario inputs. Policy assumptions for other states are summarized in Table A-2.

Table A-2 Non-California PATHWAYS Policy Scenario Assumptions

Sector	Reference Electrification Assumptions	High Electrification Assumptions <i>(Applies only to states with net zero policies in the "High Electrification" scenario)</i>
Buildings	Historical trends for heat pump space heating adoption by state Heat pump water heater "Low" scenario from EPA analysis	Heat pump sales increase to 100% for space and water heating by 2040
Transportation	Historical trends by state, no Biden-era EPA emissions standards ACC II and ACT in states that have adopted them	Biden-era EPA emissions standards
Industry	No manufacturing electrification Announced semiconductor plan investment by state Existing electrolysis loads	Electrification from the "Collective Action" scenario from the US Climate Alliance "All Hands on Deck" report ⁵⁸ Additional loads due to projected clean energy manufacturing Electrolysis consistent with Biden Administration Long-term Strategy hydrogen demands
Data centers	E3 forecast on data center growth over time	E3 forecast on data center growth over time

PATHWAYS Default Input Data Sources

PATHWAYS calculates energy demand for the building and transportation sectors by taking the base year energy demand and applying a stock rollover model to calculate future energy demands. The stock rollover is based on key drivers which determine the overall growth in

⁵⁸ United States Climate Alliance. 2023. [2023 Annual Report All Hands on Deck](https://usclimatealliance.org/report/2023-annual-report/). December. <https://usclimatealliance.org/report/2023-annual-report/>.

energy demand, policy measures defined in each scenario, and the lifetime of devices (e.g. vehicles, appliances) that serve end-uses in each sector. Inputs used for the base year and stock rollover are summarized in Table A-3.

Table A-3 PATHWAYS Input Data Sources

Input	Data Source
Key drivers (population, number of housing units, commercial square footage, and growth rates)	California Energy Demand Forecast 2023, 2023-2040 Baseline Forecast Planning Area Economic and Demographic Assumptions (Form 2.2) ⁵⁹
Base year electricity and natural gas sectoral energy demands	2023 Integrated Energy Policy Report (IEPR) ⁶⁰
Base year sectoral energy demands for fuels other than electricity and natural gas	U.S. Energy Information Administration (EIA) State Energy Data System (SEDS) ⁶¹
Device Lifetimes, Transportation	EPA MOVES 3 ⁶²
Device Lifetimes, Buildings	EIA Residential Energy Consumption Survey (RECS) 2020 ⁶³ , LEAP Weibull Curves

The building (residential and commercial) and transportation sectors are further divided into subsectors representing distinct end-uses (e.g. space heating, cooking, etc.). Each subsector utilizes inputs for a range of different devices available to serve the end-use (e.g. devices for space heating include heat pumps, electric resistance heat, gas furnace, etc.). PATHWAYS uses the stock (number of devices), service demand (energy output required), and device efficiency to calculate the energy demand of each subsector. Default data sources for each subsector are summarized in Table A-4.

Table A-4 PATHWAYS Default Device Input Data Sources

Subsector	Stocks	Service Demands	Device Efficiency
Residential Central Air Conditioning	EIA RECS 2020 ⁶⁴	EIA NEMS ⁶⁵	EIA NEMS
Residential Clothes Drying	EIA RECS 2020	EIA NEMS	EIA NEMS

59 California Energy Commission. "[California Energy Demand, 2023-2040](#)." 2023-iepr-workshops-notice-and-2.

60 Ibid.

61 U.S. Energy Information Administration. 2026. "[State Energy Data System \(SEDS\): 1960-2024 \(complete\)](#)". June 26. <https://www.eia.gov/state/seds/seds-data-complete.php?sid=US>.

62 U.S. Environmental Protection Agency. 2025. "[Tools to Develop or Convert MOVES Inputs](#)." November 17. <https://www.epa.gov/moves/tools-develop-or-convert-moves-inputs>.

63 U.S. Environmental Protection Agency. 2021. "[2020 RECS Survey Data](#)." <https://www.eia.gov/consumption/residential/data/2020/>.

64 Ibid.

65 U.S. Energy Information Administration. 2023. [National Energy Modeling System](#). <https://www.eia.gov/outlooks/aeo/nems/documentation/>.

Subsector	Stocks	Service Demands	Device Efficiency
Residential Clothes Washing	EIA RECS 2020	EPA Energy Star data ⁶⁶	EIA NEMS
Residential Cooking	EIA RECS 2020	EIA NEMS	ACEEE Induction Cooking Technology Design and Assessment, 2014 ⁶⁷
Residential Dishwashing	EIA RECS 2020	EIA NEMS	EIA NEMS
Residential Freezing	EIA RECS 2020	EIA NEMS	EIA NEMS
Residential Exterior Lighting	DOE 2020 ⁶⁸	EIA NEMS	EIA NEMS
Residential General Service Lighting	DOE 2020	EIA NEMS	EIA NEMS
Residential Linear Fluorescent Lighting	DOE 2020	EIA NEMS	EIA NEMS
Residential Reflector Lighting	DOE 2020	EIA NEMS	EIA NEMS
Residential Refrigeration	EIA RECS 2020	EIA NEMS	EIA NEMS
Residential Room Air Conditioning	EIA RECS 2020	EIA NEMS	EIA NEMS
Residential Single Family Space Heating	EIA RECS 2020	EIA NEMS	EIA NEMS
Residential Multi Family Space Heating	EIA RECS 2020	EIA NEMS	EIA NEMS
Residential Water Heating	EIA RECS 2020	EIA NEMS	EIA NEMS
Commercial Air Conditioning	EIA CBECS 2018 ⁶⁹	EIA NEMS	EIA NEMS
Commercial Cooking	EIA CBECS 2018	EIA NEMS	EIA NEMS

66 Code of Federal Regulations. 1977. [Title 10 Appendix J2 to Subpart B of Part 430](https://www.ecfr.gov/current/title-10/chapter-II/subchapter-D/part-430/subpart-B/appendix-Appendix%20J2%20to%20Subpart%20B%20of%20Part%20430). Department of Energy. June 1. <https://www.ecfr.gov/current/title-10/chapter-II/subchapter-D/part-430/subpart-B/appendix-Appendix%20J2%20to%20Subpart%20B%20of%20Part%20430>.

67 Sweeney, Micah, Jeff Dols, Brian Fortenbery, and Frank Sharp. 2014. [Induction Cooking Technology Design and Assessment](https://www.aceee.org/files/proceedings/2014/data/papers/9-702.pdf). Electric Power Research Institute. <https://www.aceee.org/files/proceedings/2014/data/papers/9-702.pdf>.

68 U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy. 2020. [Adoption of Light-Emitting Diodes in Common Lighting Applications](https://www.energy.gov/sites/default/files/2020/09/f78/ssl-led-adoption-aug2020.pdf). August. <https://www.energy.gov/sites/default/files/2020/09/f78/ssl-led-adoption-aug2020.pdf>.

69 U.S. Energy Information Administration. 2018. ["2018 Commercial Building Energy Consumption Survey Data."](https://www.eia.gov/consumption/commercial/data/2018/) <https://www.eia.gov/consumption/commercial/data/2018/>.

Subsector	Stocks	Service Demands	Device Efficiency
Commercial General Service Lighting	DOE 2020	EIA NEMS	EIA NEMS
Commercial HID Lighting	DOE 2020	EIA NEMS	EIA NEMS
Commercial Linear Fluorescent Lighting	DOE 2020	EIA NEMS	EIA NEMS
Commercial Refrigeration	EIA CBECS 2018	EIA NEMS	EIA NEMS
Commercial Ventilation	EIA CBECS 2018	EIA NEMS	EIA NEMS
Commercial Space Heating	EIA CBECS 2018	EIA NEMS	EIA NEMS
Commercial Water Heating	EIA CBECS 2018	EIA NEMS	EIA NEMS
Transportation Light Duty Cars	FHWA 2021 ⁷⁰	FHWA 2021	NHTSA ⁷¹
Transportation Light Duty Trucks	FHWA 2021	FHWA 2021	NHTSA
Transportation Light Medium Duty Trucks	2021 VIUS ⁷²	2021 VIUS	EIA AEO 2023 ⁷³
Transportation Medium Duty Trucks	2021 VIUS	2021 VIUS	EIA AEO 2023
Transportation Heavy Duty Trucks (Short-haul)	2021 VIUS	2021 VIUS	EIA AEO 2023
Transportation Heavy Duty Trucks (Long-haul)	2021 VIUS	2021 VIUS	EIA AEO 2023
Transportation Buses	FHWA 2021	FHWA 2021	ANL 2021 ⁷⁴

Base Year Benchmarking

The process of calibrating PATHWAYS model inputs so that base year energy demand outputs align with historical data is referred to as benchmarking. Base year model outputs were benchmarked to the CEC 2023 Integrated Energy Policy Report (IEPR) demand forecast⁷⁵ at

70 U.S. Department of Transportation, Federal Highway Administration. 2022. [Highway Statistics 2021](https://www.fhwa.dot.gov/policyinformation/statistics/2021/). <https://www.fhwa.dot.gov/policyinformation/statistics/2021/>.

71 National Highway Traffic Safety Administration. 2026. [Central Analysis](https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/CAFE/2022-FR-LD-2024-2026/Central%20Analysis/). <https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/CAFE/2022-FR-LD-2024-2026/Central%20Analysis/>.

72 U.S. Census Bureau. 2023. [2021 Vehicle Inventory and Use Survey](https://www.census.gov/programs-surveys/vius.html). <https://www.census.gov/programs-surveys/vius.html>.

73 U.S. Energy Information Administration. 2023. [Annual Energy Outlook 2023](https://www.eia.gov/outlooks/aeo/). <https://www.eia.gov/outlooks/aeo/>.

74 Argonne National Laboratory. 2023. [Vehicle Technologies and Hydrogen and Fuel Cell Technologies Research and Development Benefits Analysis](https://vms.taps.anl.gov/reports/u-s-doe-vto-hfto-r-d-benefits-analysis-mdhd/). Vehicle & Mobility Systems Department. <https://vms.taps.anl.gov/reports/u-s-doe-vto-hfto-r-d-benefits-analysis-mdhd/>.

75 California Energy Commission. "California Energy Demand, 2023-2040." <https://www.energy.ca.gov/data-reports/reports/2023-integrated-energy-policy-report/2023-iepr-workshops-notice-and-2>.

the planning area level for electricity and natural gas, and historical energy consumption from the EIA State Energy Data System (SEDS)⁷⁶ at the state level. For this study, 2022 was used as the base year given that at the time of analysis, 2022 was the most recent year in the CARB inventory. Details on the benchmarking process for the California PATHWAYS model are provided in Table A-5. For other Western U.S. states, benchmarking was conducted at the state level using EIA SEDS.

Table A-5 California 2022 Base Year Benchmarking Assumptions

Sector	Benchmarked to	Benchmarking Adjustments Made
Buildings (Residential)	Electricity and Natural Gas: CEC 2023 IEPR Other Fuels: EIA SEDS	Aligned stocks (per capita) and stock share by fuel/technology with the CEC 2019 Residential Appliance Saturation Survey (RASS) ⁷⁷ Service demands for space heating, water heating, and refrigeration aligned with RASS
Buildings (Commercial)	Electricity and Natural Gas: CEC 2023 IEPR Other Fuels: EIA SEDS	Space heating and water heating service demands scaled so that statewide commercial natural gas consumption in PATHWAYS matches IEPR in the base year

76 U.S. Energy Information Administration. 2026. "[State Energy Data System \(SEDS\): 1960-2024 \(complete\)](https://www.eia.gov/state/seds/seds-data-complete.php?sid=US)". June 26. <https://www.eia.gov/state/seds/seds-data-complete.php?sid=US>.

77 DNV GL Energy Insights USA, Inc. 2020. [2019 California Residential Appliance Saturation Study](https://www.energy.ca.gov/sites/default/files/2021-08/CEC-200-2021-005-ES.pdf). California Energy Commission. Publication Number: CEC-200-2021-005-ES. <https://www.energy.ca.gov/sites/default/files/2021-08/CEC-200-2021-005-ES.pdf>.

Sector	Benchmarked to	Benchmarking Adjustments Made
Transportation	Electricity: CEC 2023 IEPR Other Fuels: EIA SEDS	Base Year efficiency (MPG) calculated from CARB EMFAC 2021 Inventory ⁷⁸ Light-Duty Vehicle (LDV) stocks (per capita) and stock share by fuel aligned with CEC vehicle registration data ⁷⁹ Adjusted share of residual fuel oil and distillate in the shipping sector based on International Renewable Energy Agency (IRENA) data ⁸⁰ Adjusted Heavy Duty Vehicle (HDV) vehicle miles travelled (VMT) to match EIA SEDS distillate demand
Industry	Electricity: CEC 2023 IEPR Other fuels: EIA SEDS	Fuel consumption allocated to regions and subsectors based on proportions in the CARB 2022 Emissions Inventory ⁸¹ Industrial energy demand in the PATHWAYS model is a direct input from IEPR and SEDS; no further benchmarking is needed to match total demand

78 California Air Resources Board. "[On-Road \(EMFAC\)](https://ww2.arb.ca.gov/our-work/programs/msei/on-road-emfac)." <https://ww2.arb.ca.gov/our-work/programs/msei/on-road-emfac>.

79 "[Vehicle Population Last updated 04-30-2024 ada.xlsx](https://www.energy.ca.gov/files/zev-and-infrastructure-stats-data)" from <https://www.energy.ca.gov/files/zev-and-infrastructure-stats-data>.

80 International Renewable Energy Agency. 2021. [A Pathway to Decarbonise the Shipping Sector By 2050](https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Oct/IRENA_Decarbonising_Shipping_2021.pdf). https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Oct/IRENA_Decarbonising_Shipping_2021.pdf.

81 California Air Resources Board. "[Current California GHG Emissions Inventory Data](https://ww2.arb.ca.gov/ghg-inventory-data)." <https://ww2.arb.ca.gov/ghg-inventory-data>.