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California Energy Commission

DRAFT STAFF REPORT

California Energy Resource and Reliability Outlook, 2024

Reliability Analysis Branch
Energy Assessments Division

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California Energy Commission

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ABSTRACT

The *California Energy Resource and Reliability Outlook* is the California Energy Commission's comprehensive, statewide assessment of electric and natural gas energy resource planning and reliability for the upcoming summer and midterm, spanning the next five years. Outlooks in future years will include petroleum resources.

The intent of this *California Energy Resource and Reliability Outlook* is to provide a complete picture of planning and reliability for all investor-owned utilities and publicly owned utilities in California for the period of 2024–2028, to the extent that data are available.

Keywords: Reliability, reliability planning assessment, California ISO, CEC, CPUC, DWR, California, electricity, supply and demand, extreme event, electricity system planning, resource stack analysis, summer reliability, resource procurement

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EXECUTIVE SUMMARY

The *California Energy Resource and Reliability Outlook* is the California Energy Commission's (CEC) comprehensive, statewide assessment of energy resource planning and electric and natural gas reliability for the upcoming summer and the midterm, spanning the next five years. Over the next five years, California electric utility resource plans are projected to meet grid reliability planning standards for the state. For summer 2024, California has a low risk of need to dispatch contingency resources during extreme events, similar to the heat waves experienced in 2020 and 2022. However, delays to ongoing battery storage build-out could create challenges. Additionally, coincident catastrophic wildfires impacting transmission during an extreme heat event would result in the need to dispatch contingency resources. On the gas side, supply coming into the state have improved over the last year and storage is projected to be sufficient to meet peak summer demand. Absent a multi-day, hot weather event with additional infrastructure outages, the risk to reliability is low.

Updated 2024 Summer Conditions

This report provides an overview of the conditions shaping the California energy landscape with a focus on the upcoming 2024 summer season, offering insights into the key aspects that ultimately influence reliability. The report includes a broad assessment of reliability that considers Western and national trends that impact California, including the following:

Summer 2024 – California outlook is cautiously optimistic for electric and natural gas reliability, but contingency resources may be needed in a coincident of extreme events.

- West wide Weather[1]: Summer climate forecasting predicts normal temperatures in the coastal areas of California, Oregon and Washington and higher than average temperatures in the rest of the West this year, which means widespread heat events and challenging grid conditions are likely. A coincident west wide heat event would be a particularly challenging scenario, reducing imports available to California when they are needed most.
- West wide Fire Outlook[2]: Summer fire season can also impact reliability due to damage, interruption, or derating of equipment by fires and other events, reducing the availability of supply or impacting transmission capacity into or within California. This summer, significant fire potential is normal or above normal in California through October. Above normal fire potential is expected through

1 Informed by the California ISO's 2024 Summer Meteorological Outlook presented at the CEC's May 29, 2024, Summer Reliability Workshop, as well as the Climate Prediction Center's updated Seasonal Temperature Outlooks. May no longer be consistent with the forecasting presented at the May workshop.

2 Informed by CAL FIRE's May - August 2024 Seasonal Outlook presented at the CEC's May 29, 2024, Summer Reliability Workshop, as well as the WFTIIC Four Month Outlook released on July 2, 2024, for July, August, September, and October. May no longer be consistent with the forecasting presented at the May workshop.

September in areas of Oregon and Nevada traversed by major transmission import paths. Much of British Columbia is currently in drought and extreme wildfire risk conditions creating a potential risk to imports.

- West wide Reliability: As California is part of a larger Western Interconnection and is a net importer of electricity, the conditions in the rest of the West have the potential to impact California's electric reliability. Under 2024 normal operating conditions, the Western Interconnection is projected to have sufficient supply and transfer capability, except for a small part of Mexico, which has the potential for insufficient operating reserve in above normal operating conditions. This potential is not expected to affect electric reliability in California.
- California New Resources: California continues to grow its resource portfolio. Between January 2019 and June 2024, the state has added 22 GW of new clean energy capacity, signaling a remarkable uptick in new resource additions. New resource additions are critical to meeting statewide reliability needs. This includes over 10 GW of battery energy storage capacity, with about 8.9 GW being utility-scale storage, and over 9.7 GW of solar PV. Energy storage continues to provide critical value by charging with excess resources in mid-day and discharging later in the day as solar is declining.

California has added 22 GW of new resources since January 2019, signaling a remarkable uptick in new resource additions .

- Department of Water Resources Hydroelectric Conditions: Hydroelectric resources provide an average of 14.57 percent of the state's electricity needs and up to 7,000 MW of peak capacity to support reliability. The April snowpack report from the Department of Water Resources (DWR) shows that the statewide snowpack's snow water was 110 percent of the April 1 average. In combination with significant reservoir levels, hydroelectric generation is anticipated to be at least at average levels.

Electric and Gas Reliability

California is experiencing a substantial shift in conditions affecting the electric grid, as it transitions to a clean energy future, while confronting the impacts of climate change. Senate Bill 100 (De León, Chapter 312, Statutes of 2018) sets an ambitious target of powering all retail electricity sold in California and state agency electricity needs with renewable and zero-carbon resources by 2045 to reduce greenhouse gas emissions and help improve air quality and public health. The actions to achieve Senate Bill 100 are resulting in the addition of unprecedented quantities of clean energy resources, primarily utility scale solar and storage. Non-fossil-fuel sources now make up 61 percent of retail electricity sales in California.

At the same time, climate change is causing substantial variability in weather patterns and an increase in climate-driven extreme events, which is resulting in more challenges to maintaining grid reliability. In 2020, a west-wide heat event resulted in rotating outages on August 14 and 15. In 2021, dry conditions resulted in a wildfire in Oregon that impacted transmission lines, resulting in a loss of 3,000 MW of imports to the California Independent System Operator

(California ISO) territory and 4,000 MW of overall import capacity to the state. In 2022, California experienced record high temperatures between August 31 and September 9. On September 6, 2022, the California ISO recorded a new record peak load at 52,061 MW, nearly 2,000 MW higher than the previous record. In late July 2023, parts of the west outside California experienced extreme heat, driving challenging and fast-moving market dynamics.

Western Coordination

California rt of a complex electrical system within the Western Interconnection, a network of power lines linking a diverse collection of generating resources to loads throughout the region. As such, coordination with many other entities in the Western United States is essential to electricity markets and transmission access that enable greater sharing of resources. In the *2022 Integrated Energy Policy Report (IEPR) Update*, the CEC highlighted the importance of increasing integration of the Western electricity systems through implementation of regional system planning and operation, with a particular focus on implementing markets, encouraging transmission investment, and balancing loads and resources.

Since the *2022 IEPR Update,* the most significant progress is the continued success of the Western Energy Imbalance Market, which has saved $5.5 billion for its participants, with first quarter 2024 benefits of $436 million. This success proves to potential day ahead market participants that the expanded market potential from the California ISO Extended Day Ahead Markets initiative stands to unlock significant added value. The Federal Energy Regulatory Commission has given nearly complete approval of the Extended Day Ahead Market tariff proposed by the California ISO. California utilities, including investor-owned utilities, Los Angeles Department of Water and Power (LADWP), Balancing Authority of Northern California and others have announced their intention to participate in the Extended Day Ahead Market, as have PacifiCorp, Portland General Electric and NV Energy. Idaho Power is also a candidate to join. Elsewhere in the Western Interconnection, a day ahead markets offering from the Southwest Power Pool has an initial tariff filed with the Federal Energy Regulatory Commission. Market design efforts are underway with interest from a variety of stakeholders, notably the hydroelectric rich systems of the Bonneville Power Administration and the Powerex Corporation in British Columbia, Canada.

The Western Interconnection is a synchronous machine that allows 11 western states and two Canadian provinces to operate their generation and transmission at the same frequency.

Further increasing system resilience and the benefits of markets are at least eight new large 500 kilovolt transmission additions already close to operation or under construction including TransWest Express, Greenlink, Gateway South and West, and the Southwest Intertie. Taken together, resource and transmission additions coupled with increased system integration achieved through market implementation have improved the reliability outlook for California.

Gas Plant Performance

Natural gas power plants supply a significant portion of the peaking capacity of California's electric grid and thus performance is a critical aspect of system reliability. Further, the availability of the gas fleet to respond to system operator dispatches and system ramps is at the core of system reliability. However, gas plants, like most resources, lose efficiency with excessive heat and can be more susceptible to mechanical failure. Traditional planning margins take into account an average level of resource derates, although those numbers have not been revisited for years. An assessment of outage types and timing during peak periods of summer months of 2021 through 2023 shows the impact heat events have on the performance of the gas fleet. Heat events in the study period were associated with increased derates of gas plants by nearly 300 MW, or about 9 percent, on average, nearly all attributable to ambient derates. Further analysis may benefit resource planning efforts by verifying what portion of the gas fleet should be expected to be available during heat events.

Probabilistic Reliability Analysis

This report includes a statewide probabilistic assessment for the years 2024 to 2030, utilizing the CEC's *2023 IEPR* forecast and the California Public Utilities Commission's (CPUC') 2023 Preferred System Plan for the California ISO territory. The target for probabilistic assessments is to evaluate whether resource planning is likely to achieve a one day of outage per 10 years, or 0.1 Loss of Load Expectation. CEC scenarios were modeled to assess the dependence on imports and potential for energy constraints. The analysis evaluated three scenarios regarding California's energy imports. In the first two scenarios, imports were limited to historical resource adequacy levels during peak times and throughout the day. These scenarios successfully met reliability targets for the entire study period, even if there was a 40 percent reduction in expected resources. However, the third scenario, which assumed no imports, could meet reliability targets only after 2026. If there was a 40 percent reduction in new resources, this scenario failed to meet targets in any year.

Loss of load expectation (LOLE) analysis assesses whether a resource portfolio achieves a 1 day of outage per 10 years standard. The approach considers the probability of a wide range of key variables and relies on thousands of simulations drawing randomly from different combinations of demand, solar, and wind profiles, as well as unexpected plant outages.

Resource Stack Analysis

To determine the potential need for contingency resources under extreme grid conditions, a resource stack analysis was conducted comparing anticipated electric supply to projected demand during the peak summer months in the California ISO balancing area. This analysis includes a 17 percent planning reserve margin to maintain reliability standards in alignment with the CPUC Resource Adequacy current planning standard. This report also expanded the resource stack analysis beyond the California ISO balancing area by incorporating the three largest publicly owned utilities: LADWP, Imperial Irrigation District, and Sacramento Municipal Utilities District (SMUD).

With the 3 added utilities, the resource stack analysis shows that there is a 6,700 MW surplus available during the most challenging hour in September under average conditions. July and August show a similar pattern of surplus during the net peak period. However, under extreme events, the surpluses are 3,400 MW (2020 equivalent event) and 1,400 MW (2022 equivalent event). This broader scope provides a more holistic understanding of the statewide supply and demand situation, revealing a positive outlook under extreme events and creating opportunities for inter-area coordination.

For the California ISO balancing alone, the latest CEC resource stack analysis for summer 2024 reveals an addition of 966 MW of net qualifying capacity, compared to the May 2024 *Joint Agency Reliability Planning Assessment*, to support peak demand and enhance system reliability. Under average conditions, the state could see up to 4,800 MW of surplus, assuming all projected new resources come online on time. Conditions consistent with 2020 and 2022 equivalent extreme heat events are also projected to have sufficient capacity. Contingencies likely would only be required in the event of a coincident extreme heat event and a wildfire that impacts transmission, similar to the July 2021 Bootleg Fire.

For the California ISO territory there is anticipated to be sufficient capacity for average conditions and for events similar to what the state experienced in 2020 and 2022.

This report also analyzed the impact of resource delays, highlighting the significance of additional battery storage in maintaining reliability. A 40 percent delay in battery storage resource deployment could shift system conditions from a surplus to a modest need for contingencies under extreme events. While supply chains for some resources have improved since the pandemic, there remain delays in the availability of ancillary equipment, such as transformers and circuit breakers, ranging from 10 months to 2.5 years.

It is crucial to acknowledge that real-time conditions may deviate from projections due to factors such as construction delays, weather, permitting issues, and extended outages. Thus, while the resource stack analysis offers valuable insights, it is essential to continue to monitor system conditions and prepare for unforeseen situations where contingency resources may be needed.

Gas System Reliability

CEC staff analyzed supply and demand conditions for the Southern California Gas (SoCalGas) Company's and Pacific Gas and Electric (PG&E) Company's natural gas pipeline systems for summer 2024 to inform policy makers and the public about the risk of service interruptions, particularly as they may impact availability of natural gas for electric generation. Absent a multi-day hot weather event combined with any additional infrastructure outages, the risk to SoCalGas and PG&E gas service reliability is low.

- SoCal Gas: A key pipeline returned to service in February 2023, thereby increasing capacity on SoCalGas's southern system. SoCalGas continued repairs to its northern system, returning to its design capacity of 1,590 million cubic feet per day despite a major gas transmission line, Line 3000, operating at reduced pressure. However, ongoing maintenance on the northern system during the summer continues to hamper deliverability and has reduced capacity from this nominal amount. Even with the unplanned and planned maintenance, staff find the risk of service interruptions is low this summer. This is largely due to the return to service of El Paso Natural Gas Pipeline's southern mainline; therefore, the southern zone is assumed to be at full capacity. Staff projects zero curtailment on a peak summer day, confirmed through modeling and technical analysis, including the CEC gas demand forecast.

The natural gas system is anticipated to have sufficient capacity to meet summer demand

- PG&E has sufficient pipeline capacity to meet the projected peak day demand, and should an extreme peak day like September 2022 occur, PG&E also has access to underground storage. Staff concludes PG&E summer reliability to be adequate.

Emergency Preparedness

The California Natural Resources Agency assigned the role of co-lead agency for California Emergency Support Function 12 Utilities to the CEC. The role of California Emergency Support Function 12 Utilities is to provide information, resources, and support in partnership with the private sector to restore gas, electric, water, wastewater, fuel, and telecommunication systems. The CEC supports the state's emergency response efforts by gathering and analyzing critical energy sector information, maintaining subject specific technical expertise, and coordinating energy contingency planning activities with key stakeholders. As both the California Emergency Support Function 12 Utilities co-lead and the State Energy Office, the CEC maintains and updates the state's Energy Emergency Plan.

Extreme heat events and wildfires remain a threat to grid reliability and can strain the grid for days or weeks. The Strategic Reliability Reserve was developed in 2022 as part of Assembly Bill 205 (Committee on Budget, Chapter 61, Statutes of 2022) to expand the resources capable of managing or reducing net-peak demand during extreme events. The Strategic Reliability Reserve provides funding to secure conventional generation, efficiency upgrades at existing natural gas plants, demand response, distributed generation, and energy storage. It consists of three programs, two of which are administered by the CEC, and one is administered by the DWR. In 2024, the Strategic Reliability Reserve programs could provide up to 3,500 MW of contingency resources. Additionally, an estimated 1,000 MW of supplemental contingency resources could be available from other programs, which include balancing authority emergency transfers, additional thermal capacity, imports, and ratepayer programs.

Coordinated planning and a high degree of communication, as well as contingency resources secured through the Strategic Reliability Reserve, continue to factor into the success of response to challenging grid conditions resulting from extreme events. The coordinated planning includes maintaining and operationalizing the California ISO's operational playbook, which fosters collaboration and communication with

In response to the Infrastructure Investment and Jobs Act requirement to update existing state energy emergency plans, the CEC has begun the process of updating the state's existing Energy Assurance Plan. Federal funding under the Infrastructure Investment and Jobs Act is at risk if emergency plans do not meet the requirements. The Infrastructure Investment and Jobs Act requires energy emergency plans to be reorganized around Section 40108 provisions: address all energy sources, provide an updated state energy profile, provide an updated energy sector risk assessment and energy sector hazard assessment, and address multi-state, tribal, and regional coordination. Also, states are required to either submit an energy security plan for review or a Governor's letter affirming that the existing plan meets all Section 40108 provisions each year through 2025.

The process consists of three steps:

- Provide a preliminary draft of the plan for a review of progress by the U.S. Department of Energy (DOE) by September 2023. CEC staff made substantial organizational updates to the Energy Assurance Plan to meet the Infrastructure Investment and Jobs Act requirements. In December of 2023, the U.S. DOE verified that the draft California Energy Security Plan met all the requirements outlined in Section 40108.
- Provide a Governor's certification letter to the U.S. DOE by September 30, 2024, that the plan meets Infrastructure Investment and Jobs Act requirements. For the remainder of 2024, CEC staff will continue to refine the plan and engage energy sector stakeholders.
- Provide finalized plan and a Governor's certification letter to U.S. DOE by September 30, 2025. In 2025, CEC staff will hold a public workshop, cycle the plan through a muti-agency review process, finalize the plan, and submit all required documentation by the required deadline.

Conclusion

The summer 2024 outlook is cautiously optimistic based on the current projections. Climate forecasts predict higher than average temperatures across the Western United States, with significant fire potential expected to be normal or above-normal through October. Hydroelectric generation is anticipated to be at least average, supported by significant reservoir levels. The resource stack analysis shows a surplus above planning reserve margins, which allows for better coordination between balancing areas within California. However, delays in resource build-out could pose challenges during extreme events but may be covered with contingency resources. Both the Preferred System Plan and a reduced version of the Preferred System Plan are projected to meet reliability targets through 2030, indicating a robust portfolio. The risk to gas service reliability is low unless faced with prolonged heat events combined with infrastructure outages. Overall, while the projections are positive, unforeseen events and delays in resource development could still present challenges.

The CEC will continue to prepare and expand the *California Energy Resource and Reliability Outlook* annually to provide stakeholders and policy makers with a comprehensive resource for energy planning and reliability.

CHAPTER 1: Introduction

Background

California is in the midst of a major transformation of its energy systems. The state is a world leader on policies that shift energy resources from fossil fuels to clean energy resources such as solar, wind, and battery energy storage to reduce the impacts of climate change. In this transition, California is rapidly building new clean energy resources but continues to rely on an aging fossil-fueled power plant fleet for maintaining grid reliability, especially during times of high demand or when renewable sources are not producing enough power. At the same time, California is experiencing more frequent and prolonged extreme events as a result of climate change that strain the state's energy systems.

California is not alone in facing these challenges as other Western states experience similar climate impacts. In an increasingly integrated Western grid, localized extreme events in one area can impact reliability across other parts of the region. While California leads in the energy transition, other states are following with similar goals, causing greater competition for clean energy resources and the equipment necessary to integrate them into the grid. These challenges have demonstrated the need to better understand energy resource availability in the near, mid-, and long terms, as well as the reliability of the energy systems during the transition.

The *California Energy Resource and Reliability Outlook* (CERRO) is the CEC's comprehensive, statewide assessment of resource planning and reliability for the upcoming summer and the next five years. This year's report is the next evolution of the 2021 *Midterm Reliability Outlook*[3], in which the CEC provided an electric reliability outlook through 2026 and assessed the performance of critical resources such as battery storage and the gas fleet. The CEC is expanding the content from 2021 by providing a complete picture of electricity and natural gas planning and reliability of all investor-owned utilities (IOUs) and publicly owned utilities (POUs) in California, to the extent that data are available. Future annual reports will continue to provide more comprehensive analyses of energy resource planning issues, considerations, and trends. Future reports will also be expanded to include transportation fuels, so that the report will be a comprehensive analysis of all critical energy resources in the state. The intent of the CERRO is to effectively serve as a bridge document updating statewide energy sector planning relative to the state's clean energy policies, such as the *Senate Bill 100 Report*[4] that is issued every four years.

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3 CEC *Midterm Reliability Analysis* available at: https://www.energy.ca.gov/publications/2021/midterm-reliability-analysis

4 CEC *2021 SB 100 Joint Agency Report* available at: https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity

The CEC has a longstanding mandate under the Warren-Alquist Act to serve as California's primary energy policy and planning agency. By providing annual summer assessments and preparing for extreme events, the CEC plays a critical role in reporting on resource adequacy (RA). This ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand, planning, and operating reserves. Historically the CEC has provided updates on these topics in the *IEPR* or through separate, topic-specific reports. The intent of the CERRO is to combine all relevant analyses related to energy system reliability into one document on an annual basis, whether part of the Warren-Alquist Act or other legislation.

The CERRO also summarizes analyses that may be provided by CEC in other reports in collaboration with other agencies, such as the quarterly reliability reports required by Senate Bill (SB) 846 (Dodd, Chapter 239, Statutes of 2022). This CERRO may include summaries of CEC's analyses for those reports for context, and CEC staff will include any additional analyses conducted by CEC that may not be in the scope of those reports but relevant to system reliability (e.g., natural gas system reliability).

Where legislation requires reporting on a separate timeline from the CERRO, CEC staff will include summaries of those relevant reports or status updates as part of this document. Examples of relevant other requirements include:

- SB 423 (Stern, Chapter 243, Statutes of 2021) requires the CEC, in consultation with the CPUC, California ISO, and California Air Resources Board, to submit to the Legislature an assessment of emerging renewable energy and firm zero-carbon resources that support a clean, reliable, and resilient electrical grid in California. In developing the report, the assessment must identify available, commercially feasible, and near-commercially feasible emerging renewable energy and firm zero-carbon resources and distinguish which resources can address system reliability needs and local reliability needs, with an emphasis on reducing the emissions of greenhouse gases, toxic air contaminants, and criteria air pollutants. SB 423 further requires that the assessment evaluate the potential needs for, and role of, these resources using a reasonable range of resource cost and performance assumptions, as well as identify barriers to the procurement of these resources and possible pathways for additional procurement. The CEC posted the draft *SB 423 Emerging Renewable and Firm Zero-Carbon Resources Report, Assessment of Firm Zero-Carbon Resources to Support a Clean, Reliable, and Resilient California Grid* on August 2, 2024.
- Assembly Bill (AB) 209 (Committee on Budget, Chapter 251, Statutes of 2022) requires the CEC to develop recommendations about approaches to determine an appropriate minimum planning reserve margin (PRM) for local POUs within the California ISO balancing authority area (BAA). The approaches must consider climate change, extreme weather events, cost-effectiveness, and feasibility and may vary by utility type. The recommendations must include an implementation timeline, considering potential impacts on resource needs and availability of clean energy resources. The CEC must revise, as appropriate, the PRM recommendations to ensure that each local POU is adequately

accounting for its contribution to reliability. The POU PRM recommendations are captured in Appendix A of this report.

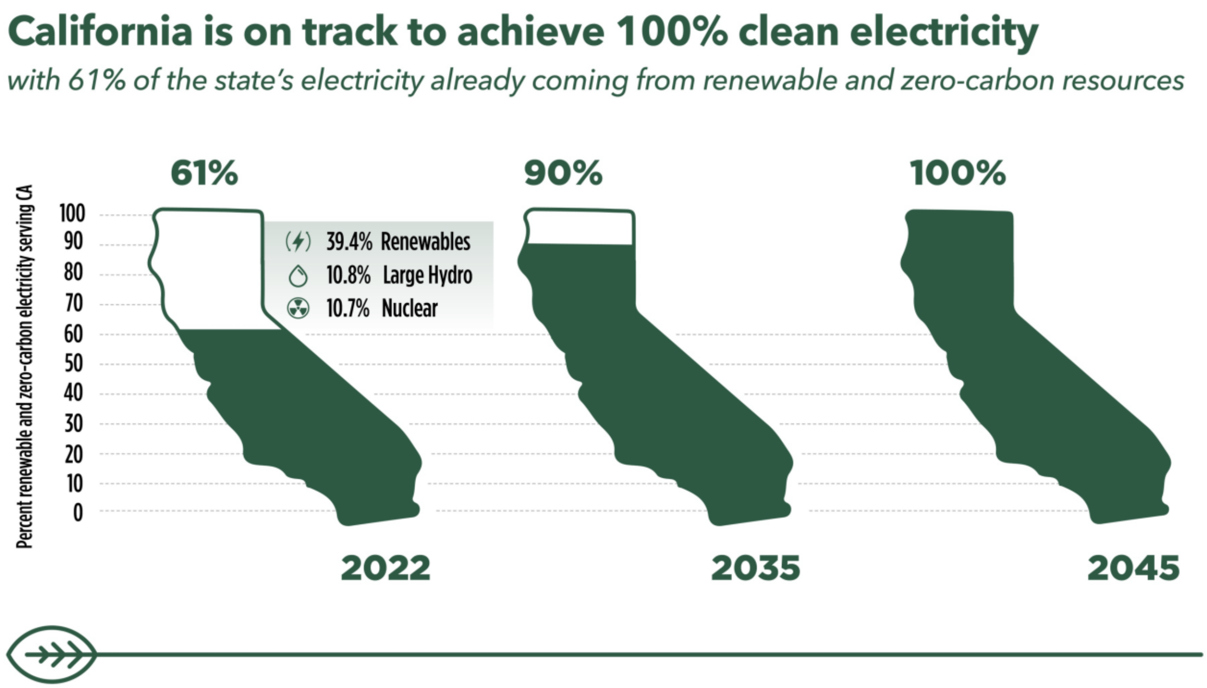
- SB 100 (De León, Chapter 312, Statutes of 2018) establishes a target for renewable and zero-carbon resources to supply 100 percent of retail sales and electricity procured to serve all state agencies by 2045. The bill also increases the state's Renewables Portfolio Standard (RPS) to 60 percent of retail sales by December 31, 2030, and requires all state agencies to incorporate these targets into their relevant planning.

California's Electricity Planning and the Clean Energy Transition

The state is a world leader on policies that shift energy resources from fossil fuels to clean energy resources such as solar, wind, and battery energy storage to reduce the impacts of climate change. The electricity sector transition is primarily driven by the state's SB 100 goal of supplying 100 percent of retail sales with renewable and zero-carbon resources by 2045. At the same time, the 2045 economy-wide carbon neutrality goal requires the electric sector to reduce greenhouse gas emissions to 8 MMT and support widespread electrification of other sectors, such as transportation and buildings. The state's electricity sector clean energy goals are largely achieved through the procurement efforts of the state's 80+ retail electricity providers. These include 40+ load serving entities, primarily regulated by the CPUC, and 40+ publicly owned utilities, primarily regulated by their local governing boards.

As of 2022, California supplies 61% of electric retail sales with renewable and zero-carbon resources. Of this, 39.4% are supplied by renewable portfolio standard (RPS) eligible resources, keeping the state on track to meeting the 60% RPS target by 2030 and 100% renewable and zero-carbon target by 2045. Between January 2019 and June 2024, the state has added 22,000 MW of new clean energy capacity, including 10,500 MW of new battery storage.

Figure 1: Progress Towards Clean Energy Goals



Source: CEC

In order to achieve the state's clean energy goals while supporting widespread electrification, the 2021 SB 100 Report estimates that California utilities will need to, on average, deploy 8 GW of new clean energy resources every year until 2045. These goals are largely achieved through retail providers integrated resource planning and procurement processes. For CPUC-jurisdiction LSEs, the CPUC's integrated resource planning proceeding directs LSEs to meet GHG reduction goals set by the California Air Resources Board, in addition to SB 100 goals. The CPUC provides guidance to LSEs, who then each develop their LSE IRP to meet the state's requirements and any LSE-specific goals. The CPUC then aggregates the portfolios and ensures they meet clean energy and reliability needs into a Preferred System Plan that is then transmitted to the California Independent System Operator for transmission planning. Additionally, the CPUC can order procurement by the LSEs to ensure reliability and clean energy goals are being met. Since 2019, the CPUC has ordered 18 GW of new net qualifying capacity to meet grid reliability needs through 2028.

The state's POUs each have their own planning and procurement process and submit integrated resource plans to the CEC at least every five years. POUs plan to the state's SB 100 and GHG reduction goals, in addition to local goals established by many local governing boards. Of the 16 largest POUs that are required to submits IRPs, at least 7 have goals that exceed the SB 100 goals by either accelerating the achievement date or achieving zero or net-zero GHG emissions, or both.

CHAPTER 2: California Grid and Western Interconnection Overview

The CEC, CPUC, California ISO and California utilities invest significant resources to undertake coordination with many other entities in the Western United States. This is essential because California is a complex electrical system and is an integral part of the Western Interconnection (WI)—a synchronous machine that allows all 14 Western states and two Canadian provinces to operate their generation and transmission at the same frequency. Should some link anywhere in the system fail to perform as required, reliability risk is triggered, and load loss could ensue there or elsewhere in the WI. In 2011, for example, San Diego lost power due to a mechanical mistake in Phoenix, Arizona.

While this may seem straightforward, it is not. The WI is an immense region with great diversity in geography, political boundaries, weather, generation characteristics, loads, and time zones. Mandatory reliability standards have been in place since 2005 and have proven necessary to ensure consistent regulation and compliance.

Balancing Authority Areas in California

Balancing authority areas (BAAs) in California play a critical role in ensuring the reliability and stability of the state's electrical grid. As regions responsible for matching electricity supply with demand in real time, BAAs manage intricate networks of power generation, transmission, and sometimes distribution. In California, these BAAs are tasked with maintaining grid frequency, managing congestion, and facilitating seamless energy transfers across interconnected systems. BAAs are subject to North American Electric Reliability Corporation (NERC) reliability standards and compliance, which are delegated to the Western Electricity Coordinating Council (WECC).

In California, the largest BAAs include the California ISO and LADWP. The California ISO is the BAA responsible for managing the bulk of the state's electrical grid, overseeing transmission, dispatching power plants, and ensuring grid reliability for about 80 percent of California's electricity consumers. LADWP, on the other hand, operates as a BAA within its service territory and for neighboring POUs in the Los Angeles Basin, managing the electricity supply and demand for Los Angeles and its surrounding areas. LADWP also operates the largest direct current (DC) interties in the California system: the Pacific DC Intertie and the Intermountain Power Project DC intertie.

Figure 2 shows several smaller BAAs within California, such as the Balancing Authority of Northern California (BANC), PacifiCorp-West (PACW), Nevada Energy (NVE), Turlock Irrigation District (TID), Western Area Lower Colorado, and the Imperial Irrigation District (IID), which manage grid operations within their respective service territories. These BAAs work collaboratively to maintain grid stability and reliability across the state.

Figure 2: Map of Balancing Authorities in California

Source: CEC

California ISO

In addition to being a BAA, the California ISO also operates various markets, including the Western Energy Imbalance Market (WEIM), which enables participating utilities to balance supply and demand efficiently across the Western United States, optimizing the use of renewable energy resources. Furthermore, the California ISO manages the day-ahead and real-time markets,[5] simplifying the scheduling and dispatch of electricity generation to meet forecasted and real-time demand. Through its market mechanisms and grid management

5 Day-ahead and real-time markets are energy markets that optimize the dispatch and cost of generation resources with the purpose of creating a competitive platform to drive down the cost of wholesale electricity.

tools, California ISO fosters competition, supports the integration of renewable energy, and maintains grid reliability, contributing to the effective functioning of California's electricity system and regional energy markets.

Other BAAs

The other BAAs outside the California ISO footprint provide similar functions to the California ISO. Some of the BAAs have additional functions that concern other utilities, such as water, or responsibilities that extend beyond the borders of California. For example, PACW and NVE serve customers in California and neighboring states. This service creates unique challenges geographically for optimizing and balancing supply and demand. However, many of these BAAs coordinate their electricity operations through the WEIM. By participating in the WEIM, BAAs can optimize the use of renewable energy resources, address grid imbalances, and reduce operational costs. Through this collaborative platform, utilities share surplus energy or access additional power when needed, enhancing grid reliability and resilience.

Western Coordination

In its *2022 IEPR Update*,[6] the CEC highlighted the importance of increasing integration of the western electricity systems through implementation of regional system planning and operation, with particular focus on implementing markets, encouraging transmission investment, and enhancing regional governance. Since the publication of the report, significant progress has been made, as highlighted below.

Western Markets: Enhancing Economics and Reliability

At least 38 balancing authorities function in the Western states and two Canadian provinces, dispatching their systems independently from one another. A central goal of regional integration is to bring these autonomous entities into more efficient coordinated methods of system dispatch. Wholesale markets are one essential mechanism to do this, including options for real-time, day-ahead, and regional full-function markets.[7]

The real-time market of greatest interest to California is the WEIM. Established in 2014, the WEIM is a real-time wholesale energy trading platform that allows participants from anywhere in the WI to buy and sell power. This market has attracted voluntary participation of 22 balancing authorities from 11 states and British Columbia.

WEIM economic benefits reported for the first quarter (January–March) of 2024 were $436 million[8] and the cumulative total since its 2014 inception is $5.5 billion, far higher than originally anticipated. Of equal importance, markets enhance reliability in normal and stressed

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6 California Energy Commission (CEC), *Final 2022 Integrated Energy Policy Report Update*, available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=250084.

7 A regional full-function market would be similar to other regions of the country where RTOs or ISOs control all facets of utility system operation, including dispatch, RA, and transmission planning."

8 California ISO "Western Energy Imbalance Market Benefits Report: First Quarter 2024", April 30, 2024. Available at https://www.westerneim.com/Documents/iso-western-energy-imbalance-market-benefits-report-q1-2024.pdf

system operations. WEIM's enhanced balancing area communication and support provided critical support during the September 2022 widespread and long-duration heat wave.[9] In Summer 2023, WEIM added the Assistance Energy Transfer mechanism, a voluntary tool allowing balancing authorities to arrange for additional WEIM energy transfers under very tight supply conditions. Five western balancing authorities relied on this tool to maintain system balance during periods of very high loads.

Major steps forward have been taken in recent years to increase coordination of system dispatch to harness diversity,[10] moving beyond real-time markets to day-ahead imbalance markets. The California ISO has pursued expansion of WEIM to the Extended Day-Ahead Market (EDAM), while the Southern Power Pool has engaged many stakeholders in developing its own version of day-ahead markets called Markets+. The Federal Energy Regulatory Commission (FERC) released Order ER23-2686-000 in December 20, 2023 granting nearly full tariff approval of EDAM. Progress continues as statements of intent to join have been received from PacifiCorp, BANC, LADWP, Idaho Power, Nevada Energy and Portland General Electric.

Additional detail on Western energy markets is provided in Appendix B.

Transmission: Regional Projects and New Planning Initiatives

"Transmission lifts all boats" is a phrase often used to reflect the benefit of adding new transmission capability. Simply stated, capacity essential to reliability may be available outside the state but can provide no support if not deliverable to load, that is, the customers who need reliable energy. Indeed, the transmission committed to the WEIM, and the available capacity were important factors in the California ISO surviving the September 2022 heat wave. New lines being added (see below) are essential to delivering remote wind energy with high-capacity factors that operate when California wind may be dormant. Additional lines also add resilience in times of fires and outages anywhere in the WI.

Despite long-running challenges with regional coordination and WECC-wide transmission planning, incremental, major transmission is getting built. Many of these projects feature designs to enable power flows across the WI from wind resources in the east to load centers in the west. The eight regional projects making progress include:

- Ten West Link, California and Arizona – merchant 500 kilovolt (kV) line (2024).
- Gateway West, Wyoming to Idaho – 500 kV and 230 kV lines developed by PacifiCorp (2024).
- Gateway South, Wyoming to Utah – 500 kV line developed by PacifiCorp (2024).
- SunZia, New Mexico and Arizona – merchant HVDC line proposing to use the novel California ISO subscriber participating transmission owner model (2026).

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9 Remarks of E. Mainzer at the California ISO Day-Ahead Market Forum, Las Vegas, Nevada, August 2023. Recording available at https://www.caiso.com/about/Pages/Blog/Posts/Evolution-of-the-WEIM.aspx.

10 System operators are able to "harness diversity" of loads and resources by expanding both markets and operations footprints so that extremes in peak load levels, or loss of generation from variable resources, tend to average out and remain more balanced.

- Boardman to Hemingway, Idaho and Oregon – 500 kV line in joint development by Idaho Power and PacifiCorp (2026).
- Greenlink North and Greenlink West, Nevada – 525 kV lines developed by NV Energy (2026).
- Southwest Intertie Project (SWIP–) - SWIP-North, Idaho to Nevada – merchant 500 kV line (2027).
- TransWest Express, Wyoming to Nevada – merchant 500 kV and 320 kV lines proposing to use the novel California ISO subscriber participating transmission owner model (2027).

While there have historically been challenges in the development of regional transmission, there has been an elevation in engagement across the WI to develop solutions as evidenced by the formation of the Committee on Regional Electric Power Cooperation Transmission Collaborative (CREPC TC) in January 2024. CREPC TC has contracted with a consultant to develop an interregional transmission cost allocation framework that might support, and even promote, multistate transmission projects in the WI.

Interconnection-wide and Continent Transmission Assessments

A broad initiative led by the Western Power Pool, known as WestTEC, has been established to assess WECC-wide transmission needs, recognizing that the current approach to planning is insufficient. A WestTEC consultant will undertake WECC-wide power flow and production cost modeling focusing on distinct 10-year and 20-year futures. The California ISO is directly engaged, and important benefits to California will include ensuring that accurate data and modeling is used in the study. Results of the study will highlight the most cost-beneficial paths and lines that can deliver renewable and zero carbon energy to meet SB 100 mandates and provide resilience in periods of extreme weather or wildfire outages.

Additional detail on interregional transmission is provided in Appendix B.

CHAPTER 3: Electric Reliability and Recent Challenges

While future editions of this report will focus more broadly on reliability across all major fuels, this edition is focused primarily on electric reliability. Electric reliability is fundamentally driven by having sufficient energy and capacity available to serve electric demand at all times of the day and year. There are both temporal and spatial elements as electricity must be generated simultaneously to consumption, or demand, and must be delivered over the complex transmission and distribution network to the location of consumption.

Planning for Reliability

Planning for electric reliability is complex and encompasses time frames ranging from real-time operations out to long-term planning for 10 or more years.

Because electric infrastructure requires substantial lead time, up to 10 years in the case of transmission, long-term planning is essential to ensuring there is adequate infrastructure in the contracting and operational time frames. Long-term planning provides guidance on what additional resources need to be procured to meet forecasted demand while achieving policy goals, such as those set forth in SB 100. In California, long-term planning is conducted through the integrated resource planning (IRP) process for CPUC-jurisdictional entities and through individual planning processes for POUs. The CPUC's IRP process also informs the California ISO's Transmission Planning Process[11] to ensure that transmission is planned for, built, and available to deliver future generation resources to load. POU BAA transmission planning occurs through their individual processes.

To ensure that adequate resources are available to the system in the operational time frame, RA planning and contracting are conducted in the 3-year to 1-month ahead time frame. Historically, utilities have contracted enough capacity to cover at least a 15 percent PRM above their 1-in-2-year demand forecast. In recent years, RA PRMs have increased because of higher levels of demand variability, largely due to climate change and an increased reliance on variable renewable energy resources to support greenhouse gas emissions reductions. RA processes also typically seek to ensure that local generation is contracted to be available in transmission constrained areas, often called "local RAs." In California, RA contracting is conducted through the CPUC's RA program for CPUC-regulated entities and through individual processes for POUs.

Ultimately, electric demand is supplied in the operational time frame and is managed by balancing authorities (BAs), as described in Chapter 2. Long-term planning and contracting should ultimately result in sufficient resources available to BAs with sufficient flexibility in the

11 California ISO Transmission Planning Process, available via https://www.caiso.com/generation-transmission/transmission/transmission-planning

right locations. Most BAAs in California encompass multiple load-serving entities or POUs; thus, it is essential that every entity conduct sufficient RA planning.

Critical Variables for California's Electric Reliability

Several variables create significant uncertainties that must be planned for and closely monitored to ensure electric reliability. These variables are demand variability, supply challenges, hydroelectric resource availability, and import availability. Demand variability has been challenging to plan for and forecast due to climate change, resulting in more frequent and prolonged heat waves that stress the electric grid. Supply challenges, including supply chain disruptions, interconnection delays, and extended permitting processes, hinder the timely completion of new energy projects. Hydroelectric resource availability fluctuates significantly based on annual water conditions, creating uncertainty in capacity. Additionally, California's reliance on electricity imports is threatened by regional supply tightening, increased load growth, and wildfire risks to transmission infrastructure. These factors collectively emphasize the importance of comprehensive planning to maintain electric reliability in the state.

Demand Variability

Demand variability has always been a critical uncertainty accounted for in electricity planning and operations. However, climate change has recently driven more intense, frequent, widespread, and long-lasting heat waves than have been observed historically. For example, the September 2022 heat wave, which resulted in record demand in California ISO, was determined to be a 1-in-27-year event based on 30-year historical data, while only a 1-in-14-year event based on 20-year historical data. To address this, California is adapting its energy demand forecast, which is based on historical demand in addition to projected factors (for example, economic growth) to include climate change-informed datasets which are supported by ongoing Electric Program Investment Charge program research such as the Cal-Adapt Analytics Engine.[12] In addition, many entities, including the CPUC's RA program, have increased their PRMs.

Figure 3 illustrates a projection of the frequency of heat events for the Sacramento region using the CanESM2 (Average) model from Cal-Adapt. The graph shows an increase in the frequency of hot days (above 100 degrees Fahrenheit) and extremely hot days (above 110 degrees Fahrenheit). There is a clear upward trend in the frequency of heat events starting in the early 2000s. In addition to more frequent heat events, heat events are projected to be of longer duration as seen in Figure 3. Consecutive heat event days can create greater stress on the electric grid because there is extended use of air conditioning and grid assets cannot sufficiently cool overnight, as extended heat events result in warmer night temperatures.[13]

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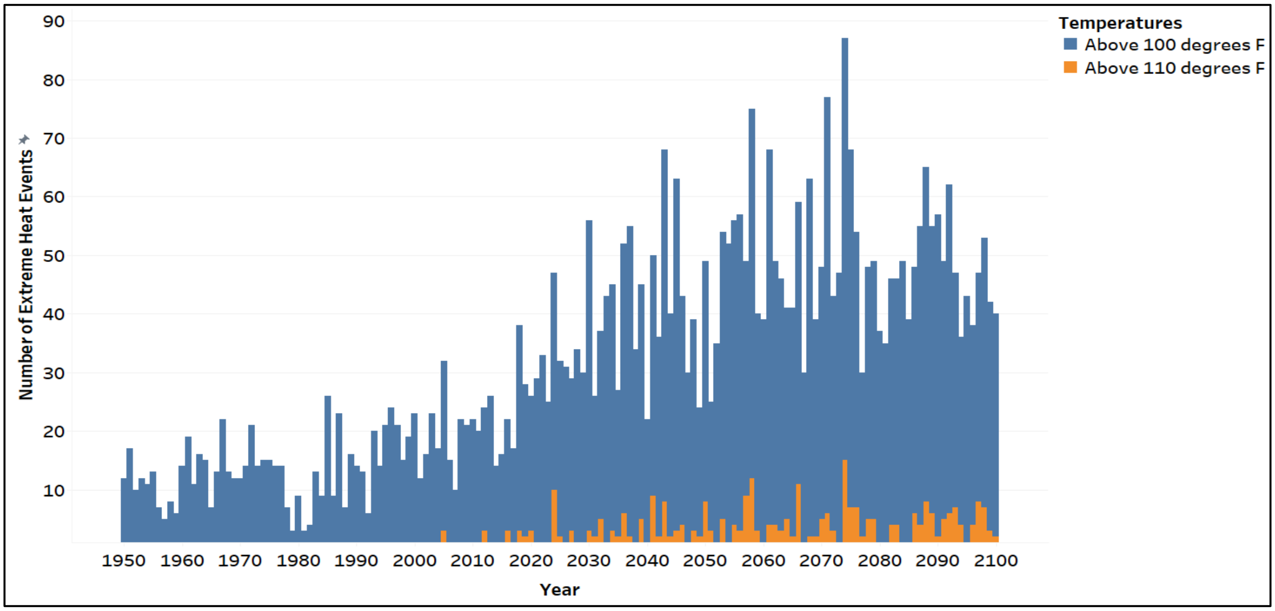
12 Cal-Adapt, *Climate Tools and Data*, available at: https://analytics.cal-adapt.org/

13 CAISO Warns Excessive Heat Will Stress Power Grid. Available at https://energized.edison.com/stories/caiso-warns-excessive-heat-will-stress-power grid#:~:text=Several%20consecutive%20days%20of%20high%20heat%2C%20along%20with%20warmer%2Dthan,between%20periods%20of%20heavy%20use.

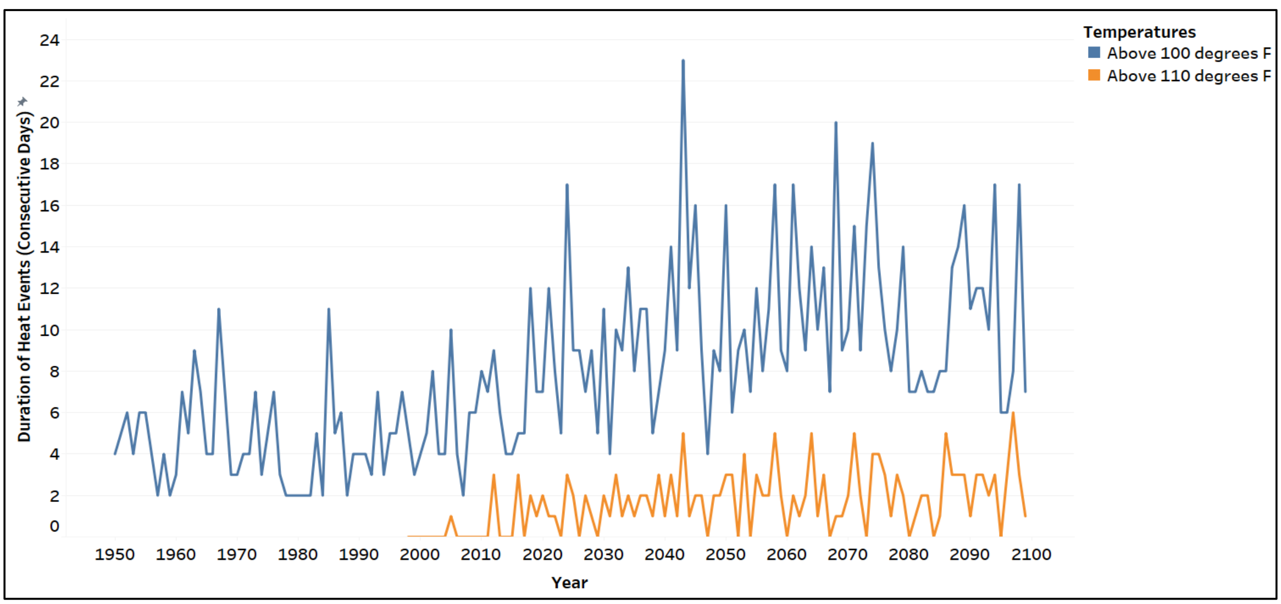
While Figure 3 and Figure 4 report on projections in the Sacramento Region, similar patterns may be seen in other areas across the state.

Figure 3: Projected Frequency of Extreme Heat Per Year – Sacramento Region



Source: CEC staff with Cal-Adapt data

Figure 4: Projected Duration of Extreme Heat Events - Sacramento Region



Source: CEC staff with Cal-Adapt data

While previous forecasts have considered expected increases in average temperature, the trends depicted in Figure 3 and Figure 4 underscore the importance of expanding climate considerations in the forecast to reflect novel weather patterns and changes to the magnitude, frequency, and duration of extreme temperatures.

Supply Challenges

Beyond adequate system planning, new resource build-out is another critical variable to California's electric reliability. Supply chain issues, interconnection delays, and permitting delays significantly impact the timely completion of new energy projects, posing challenges for system reliability. Supply chain disruptions can result in shortages of key components, such as circuit breakers and transformers, increasing costs and extending project timelines.

Interconnection delays, often due to grid infrastructure limitations, construction, or lengthy administrative procedures, further postpone the integration of new energy projects. Furthermore, permitting processes can become extended, in part by the sheer volume of projects that are requesting permits and additional requirements to ensure project safety and environmental protection. The combination of these factors can stall project initiation and completion. These combined factors delay the availability of new capacity, potentially leading to capacity shortages and affecting the overall reliability of the electric system. Addressing these issues and preparing for uncertainties in resource build-out are crucial for ensuring a reliable system.

Hydroelectric Resource Availability

Hydroelectricity comprises, on average, about 14.57[14] percent of California's annual in-state electric generation. This number can range from more than 40,000 gigawatt-hours (GWhs) in a "high hydro" year, where there is an above average snowpack and reservoirs are significantly filled, to just 15,000 GWh during an extended drought. While the impact is less significant to reliability, as water can be "held back" to be available at the peak hours of the peak months, available capacity can vary from 6,000 to 7,000 MW,[15] depending on the availability of water that year. This variability creates uncertainty for entities that depend on hydroelectric capacity for meeting their RA needs and for the state in years that every MW of capacity is needed.

Import Availability

California is a net importer of electricity, particularly in the evening hours when electricity demand is the highest. About 29 percent[16] of the state's electricity needs are served by imported electricity. Entities also depend on imports, through either long-term contracts or the short-term market, to meet their RA needs. Several trends in California and the WI create significant uncertainty in the availability of imports in the long term and, in some cases, the operational time frame. Figure 5 shows the historical hourly profile of the highest load days of the year between 2020 and 2023. As shown in Figure 5, imports play a critical role in meeting customer demand, on the most extreme days.

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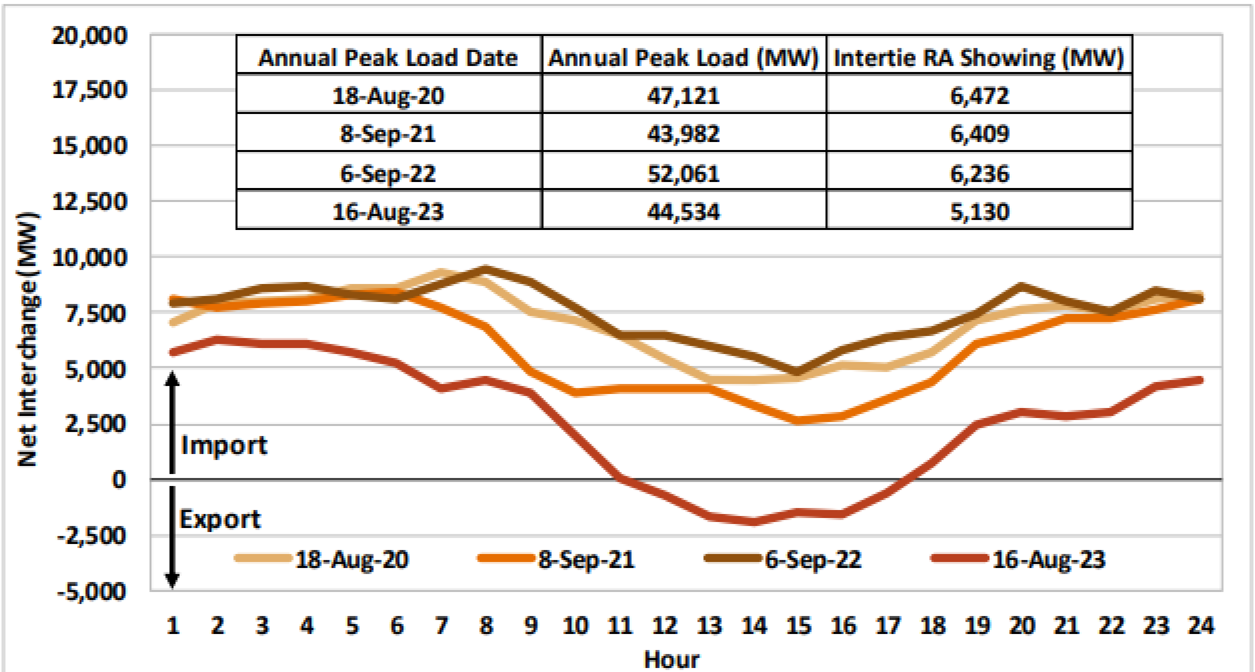
14 California Energy Commission. "*California Electrical Energy Generation*," https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-electrical-energy-generation.

15 California Independent System Operator, "*Reliability Requirements*," https://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

16 California Energy Commission. "*California Electrical Energy Generation*," https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-electrical-energy-generation.

Figure 5: Historical Net Interchange on Annual Peak Load Days (2020 – 2023)



Source: California ISO

The first trend is the tightening of supply throughout the WI. As recently as five years ago, there was an abundance of electricity supply in the WI. However, the need to increase clean energy and reduce greenhouse gas emissions has resulted in the closure of fossil fuel generators, mostly coal plants, throughout the WI, reducing capacity availability. At the same time, many states are expecting load growth because of economic growth, electrification plans, and new demand in the form of data centers and related performance computing infrastructure.

Moreover, utilities throughout the West have joined or are anticipated to join the Western RA Program,[17] which may reduce the availability of some out-of-state capacity to California due to increased contracting requirements for out of state utilities.

The second is the threat of wildfire to the state's transmission infrastructure. Imports are transported into the state to load centers through transmission lines. Critical northwest hydroelectric import paths run through fire prone areas in Oregon. All transmission import paths, most of the in-state transmission lines, and most of the in-state hydroelectric resources and geothermal generators and gen-ties cross extreme or elevated fire-threat areas as defined by the CPUC and the California Department of Forestry and Fire Protection. The Bootleg Fire in July 2021 demonstrated the risk wildfire poses to system reliability when the fire impacted the California Oregon Intertie, causing the intertie to be derated or reduce capacity by 4,000 MWs.

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17 Western Resource Adequacy Program details available at: https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

While no load shedding actions were taken, this caused the California ISO to request energy assistance and energy conservation measures – through an Energy Emergency Alert 2.

Finally, the same dynamics creating more variability in hydroelectric resource availability in California also impact hydroelectric resource availability in the Pacific Northwest, though not typically in the same year. As hydroelectric resources in the Pacific Northwest must serve local loads first, a below average water year results in less import availability to California.

Recent Reliability Conditions in California

Energy reliability in California and nationally is increasingly impacted by highly variable weather events driven by climate change. California's electric system runs reliably without issue most of the time, and the state has backup assets in place to provide power during extreme events and avoid outages. The state's greatest electric reliability concerns are driven by a small number of hours during increasingly intense historic heat events when demand for electricity skyrockets to unprecedented levels and available supply is constrained. If these moments of extreme weather events coincide with other climate-driven extreme events — like drought or fire — the state's energy system could be strained beyond reliability contingencies historically planned for.

In 2020, a west-wide heat event resulted in short rotating outages on August 14 and 15 because of systemwide electricity shortages of about 500 MWs. In 2021, dry conditions resulted in a wildfire in Oregon that impacted transmission lines that California depends on for reliability, resulting in a loss of 3,000 MW of imports to the California ISO territory. In 2022, the state experienced record high temperatures between August 31 and September 9. On September 6, 2022, the California ISO recorded a new record peak load at 52,061 MW, nearly 2,000 MW higher than the previous record, despite significant efforts that reduced load during this peak period.

Since 2020, California energy entities have taken steps to address the potential imbalances between the electrical supply and demand in California, especially as the electric grid transforms to rely on a high penetration of renewables and low-carbon resources. The CEC, CPUC, and California ISO substantially increased coordination on resource planning and reliability and developed the Tracking Energy Development (TED) Task Force with the Governor's Office of Business and Economic Development (GO-Biz) to track new clean energy projects under development to help overcome barriers to completion.

In December 2022, the CPUC, CEC, and California ISO entered into a memorandum of understanding that tightens the link between resource procurement and transmission planning.[18] The memorandum was developed in light of the unprecedented amount of new resources and transmission projected to be needed to meet state reliability and clean energy goals. Additionally, the CEC is continually improving the IEPR demand forecast to better account for climate change.

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18 Memorandum of Understanding between CPUC, CEC, and CA ISO available at: https://www.energy.ca.gov/sites/default/files/2023-01/MOU_Dec_2022_CPUC_CEC_ISO_signed_ada.pdf

Between November 2019 and June 2023, the CPUC mandated an unprecedented amount of procurement, which will bring on-line 18,000 MW of net qualifying capacity[19] (NQC) by 2028. In response to AB 205 (Committee on Budget, Chapter 61, Statutes of 2022), the CEC and DWR have also begun building out the Strategic Reliability Reserve (SRR). During the extreme heat event the state experienced between August 31 and September 9, 2023, the SRR was able to provide support, though it was still in early development. This support included securing imports, additional backup generation, and load reduction, which helped avert outages on September 6 when the California ISO recorded the highest demand ever in its territory. Even with these significant resource additions and strategic reserve resources, there exists uncertainty in the supply-and-demand balance in the 5- and 10-year horizons.

Gas Plant Performance

Power plant performance is a critical aspect of system reliability. Facility outages occur for a wide range of reasons at different times throughout the year. Planned outages are essential to perform routine maintenance and, in the long term, support system reliability, if timed effectively. However, if outages occur at higher rates than is accounted for in planning, due to for example, increased ambient temperature derates,[20] it may have a negative impact on reliability. The availability of the gas fleet to respond to system operator dispatches and system ramps is at the core of system reliability.

Previous analysis explored this relationship following the 2020 heat events.[21] The updated analysis, featured in Appendix C, assessed power plant performance during the summer reliability months of July, August, and September for the years 2021-2023. The analysis focused on the availability of gas capacity utilizing historical data on capacity outages and derates for resources in the California ISO system. Outage data, as published daily in the California ISO "Prior Trade Date Report," was aggregated to support categorical trend analysis across resource type, outage type and operating hour attributes. Findings of this outage analysis include the following:

- Heat events in the study period were associated with increased daily peak loads of about 21 percent, on average.
- Heat events in the study period were associated with increased daily maximum derates of natural gas resources during net peak hours by nearly 300 MW, about 9 percent, on

19 Net Qualifying capacity refers to the amount of capacity that can be counted toward meeting RA requirements in the CPUC's RA program. It is a combination of the CPUC's qualifying capacity counting rules and the methodologies for implementing them for each resource type, and the deliverability of power from that resource to the California ISO system.

20 An ambient temperature derate is a resource specific event whereby the generating capability of a resource is limited, or reduced, due to conditions in the surrounding environment of the resource. For example, extreme temperatures can affect the thermal efficiency and operating range of gas fired power plants.

21 Bartridge, Jim, Gerry Bemis, Mary Dyas, Elizabeth Huber, Matthew Layton, and Paul Marshall. September 2021. *Electric System Reliability and the Recent Role of California's Fossil Fleet.* California Energy Commission. Publication Number: CEC-700-2021-002, https://www.energy.ca.gov/sites/default/files/2021-10/CEC-700-2021-002.pdf

average. Nearly all the increase was attributable to outage type categories related to ambient temperature derates.

- California ISO Department of Market Monitoring (DMM) reports for the years 2020 through 2023 show that aggregate outages in September increased year-over-year between 2020 and 2022, then decreased slightly in 2023 due to milder ambient temperatures and lower loads.

Due to limitations in accessible data, additional analysis is needed to reach conclusions about systemwide outage trends to inform planning. Changes to outage reporting processes and procedures are planned topics of discussion in California ISO RA forums. Existing data sources are not easy to interpret and may have incomplete or inconsistent information.

Figure 6 shows monthly averages of the maximum daily capacity derates as represented by the maximum hourly capacity derate observed during the net peak hours of 16:00 to 21:00 for each day. On average, the daily maximum derated capacity of natural gas resources increased by 4 percent from 2021 to 2022 and decreased by about 8 percent from 2022 to 2023. The chart shows that the severity of total outages from all energy sources has increased in summer months: a 7 percent increase from 2021 to 2022, and another 5 percent increase from 2022 to 2023. Figure 6 is consistent with outage reporting from the California ISO.[22]

Refer to Appendix C for additional detail.

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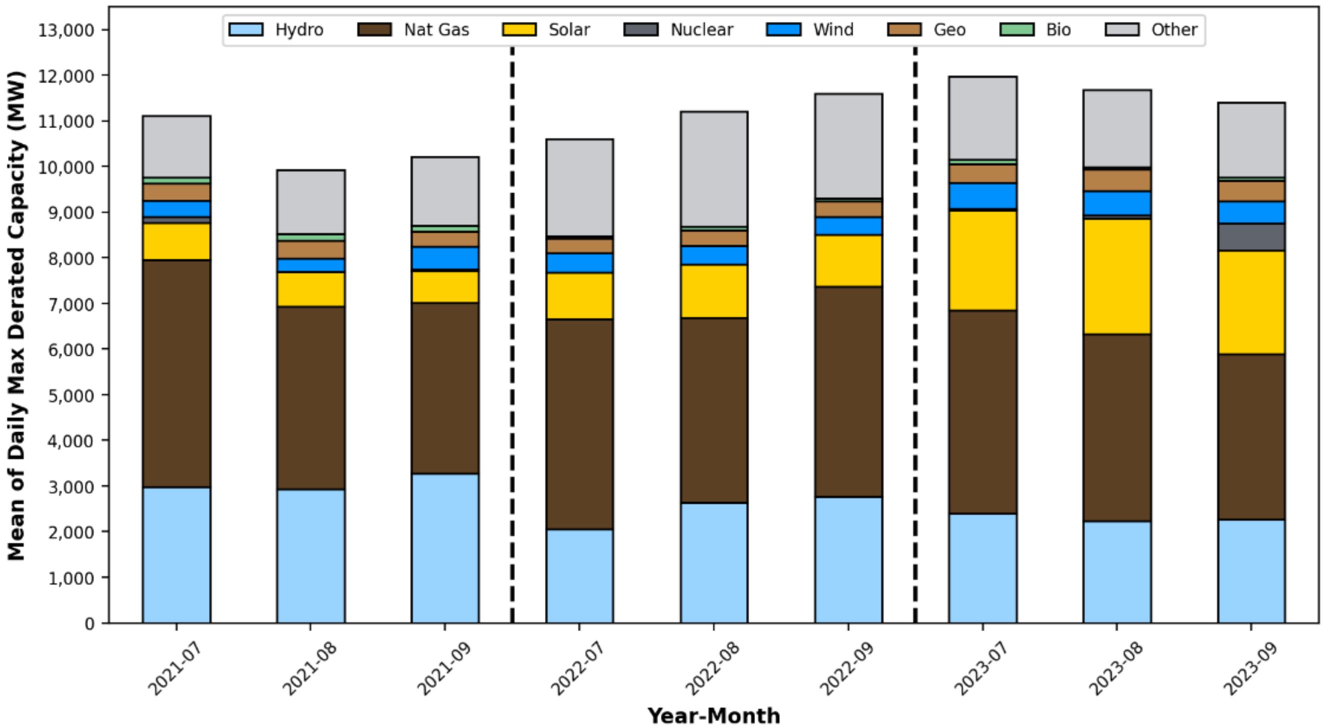
22 California Independent System Operator. July 11, 2023. *2022 Annual Report on Market Issues and Performance*, Figure 1.26, http://www.caiso.com/Documents/2022-Annual-Report-on-Market-Issues-and-Performance-Jul-11-2023.pdf.

Figure 6: Monthly Capacity Derate by Energy Source, Maximum Hourly



Source: CEC staff analysis of California ISO data

Resource Build-Out Trends in the California ISO

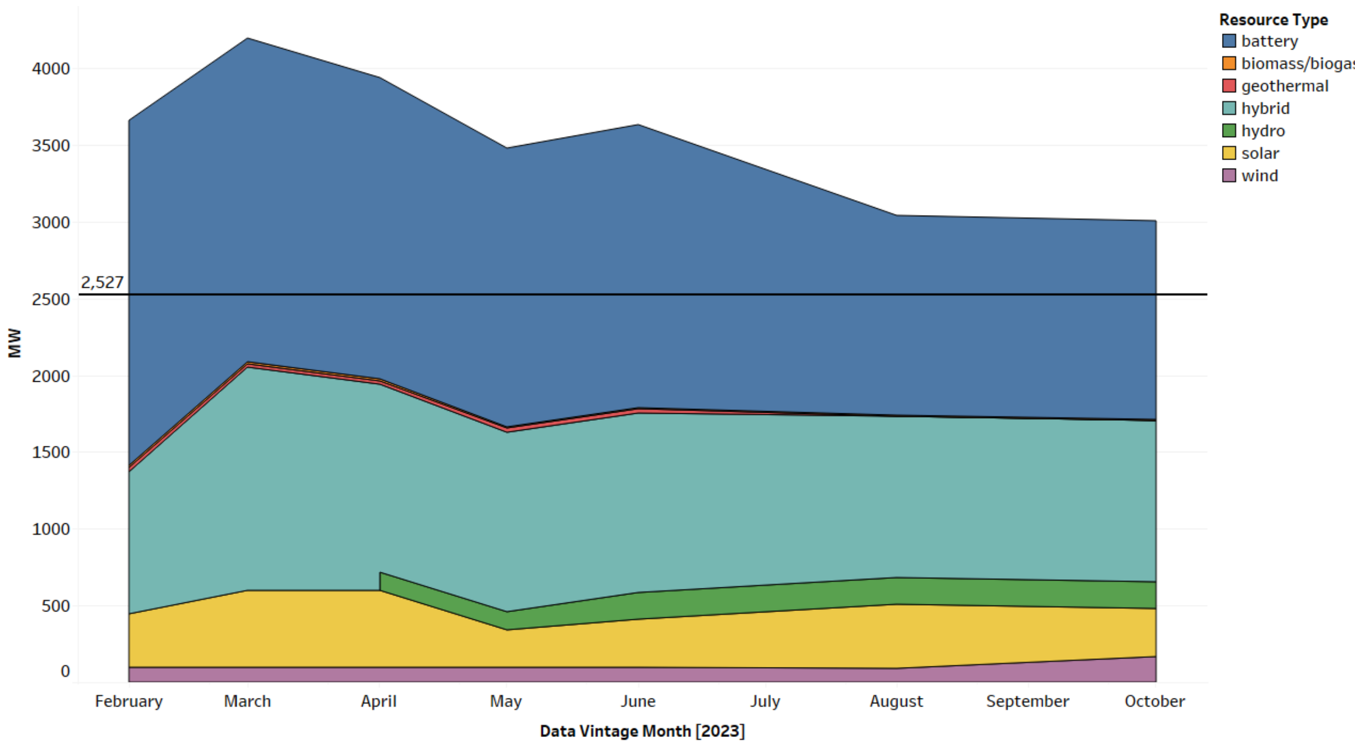
Delays to new supply resources have posed challenges to reliability in recent years and have the potential to create significant challenges to building out the state's energy infrastructure in the long term.

Particularly, these challenges have impacted energy storage technologies and the associated integration into the grid to help bolster reliability. Energy storage resources have become a primary resource for reliability as these resources allow energy from renewables to be shifted from daytime to the net-peak period when the grid is most vulnerable. In 2024, the California ISO queue consists of primarily energy storage and solar resources. While solar has minimal impact on the net peak period in the later summer months, delays to new energy storage resources may greatly impact reliability.

Understanding delays in the third quarter (July–September) is crucial for addressing summer reliability, as the third quarter encompasses the peak summer months. If load-serving entities are depending on new resources to fulfill reliability requirements during this period, delays in cumulative third quarter capacity may significantly impact reliability. Looking back, there was a decrease in projected resources for the third quarter of 2023. In each reporting month of the third quarter (shown on the x-axis in Figure 7), there is a clear trend of resource capacity decrease.

For example, load-serving entity (LSE) plans showed an initial max projection of more than 4,000 MWs of resources (March 2023 data vintage) for the third quarter of 2023, but, by end of August, the California ISO master generating capability list showed that less than 2,600 MW actually came on-line in aggregate. This number corresponds to about 1,400 MW of nameplate capacity that was not available by September, about a 35 percent delay compared to the March 2023 data vintage projections. While resources may be delayed, it was assumed that the delayed resources would come on-line by the end of the year. However, the data do not identify the cause of the decreases. The Tracking Energy Development (TED) task force discussions with developers indicate multiple challenges such as interconnection, local opposition, equipment procurement, and construction. Additional background on supply chain delays is described in the Supply Challenges section above.

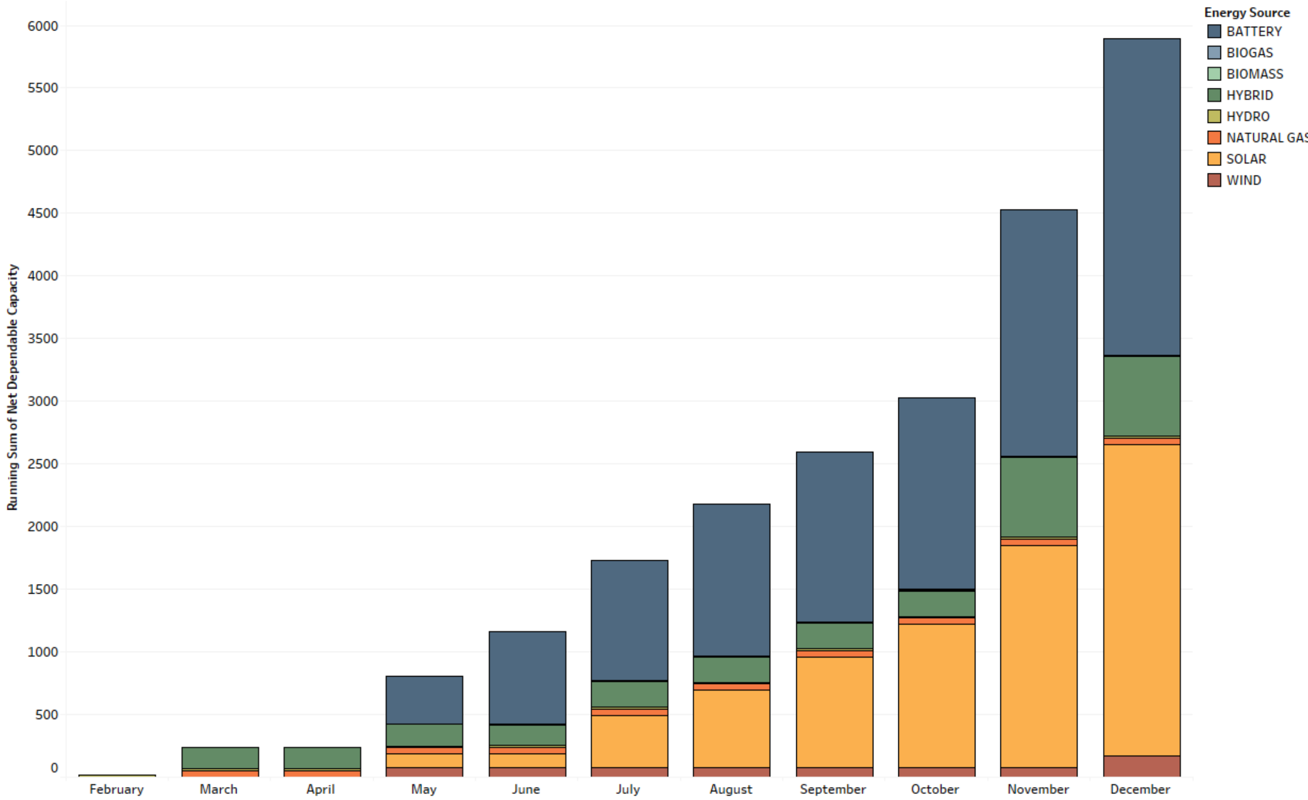
Figure 7: 2023 Q3 Expected Resources Compared to Actual Online Capacity



Source: CPUC staff on LSE plans

Figure 8 shows the cumulative resource additions in 2023 based on the actual on-line date of the resource. From September through the end of 2023, the actual capacity increases more than twofold. This increase shows that significant resource development continued to happen through the end of 2023 and that capacity is available for summer 2024. The delayed capacity coming on-line may also contribute to the large increase of capacity at the end of the year.

Figure 8: 2023 Cumulative Resource Additions

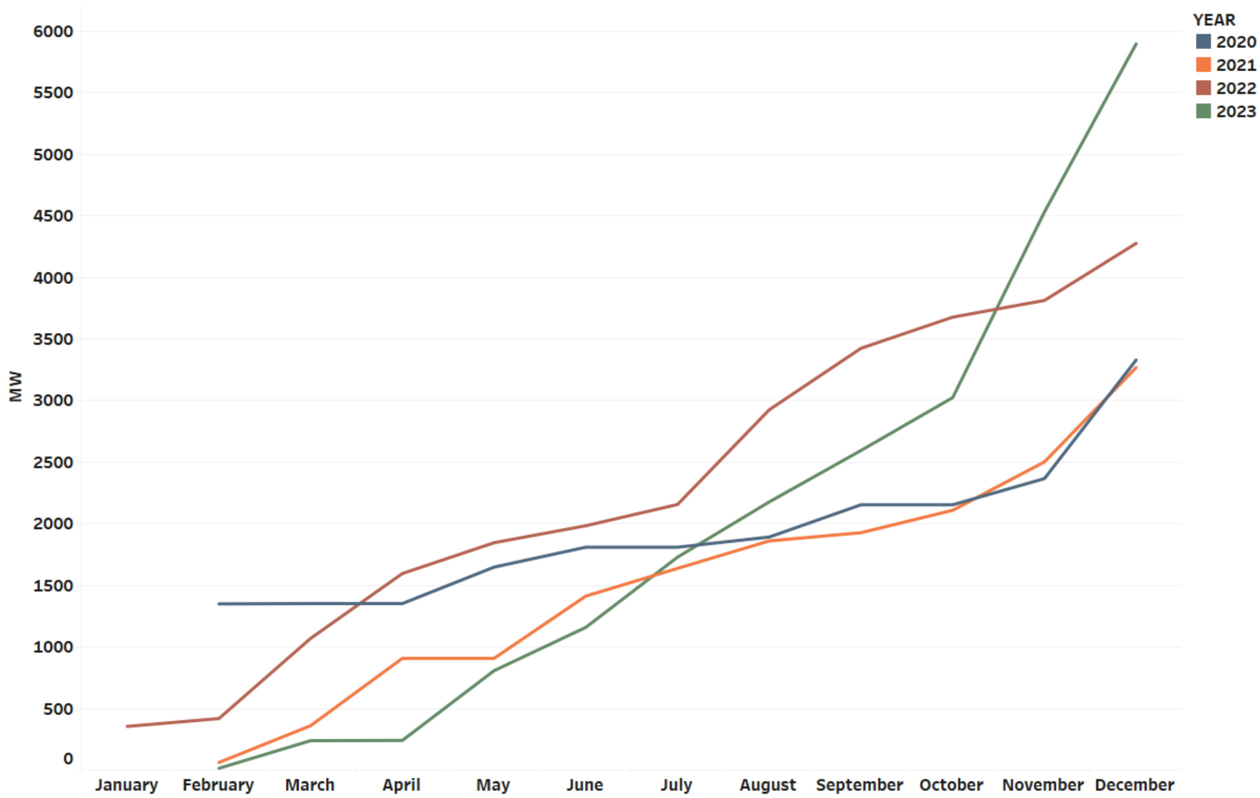


Source: California ISO master generating capability list 4/10/2024

Figure 9 shows the annual trends in new resource capacity by month. In 2020 and 2021, the resource builds were modest and gradually distributed across the months. However, 2022 and 2023 show steeper trendlines, indicating substantial amounts of capacity build-out. This provides insight into two key takeaways, for 2023:

1. The year 2023 was a record year for resource development – capping out at more than 6,000 MW of new capacity.
2. The year 2023 had fewer resources come on-line by start of September compared to 2022 but more than 2020 and 2021. Additional factors, such as weather-induced delays in spring 2023, may have caused delays for projects.

Figure 9: 2020–2023 Annual Trends



Source: California ISO master generating capability list as of 4/10/2024

CHAPTER 4:
2024 Summer Electric Conditions

Summer Climate Outlook

California peak electrical loads are driven by high temperatures and air conditioning usage in populated areas. The greatest risks to the electricity system tend to occur on the hottest days, especially during widespread heat affecting multiple population centers. The coincidence of high temperatures in California and the neighboring states is the worst-case scenario as imports become less available when power is needed most.

The Climate Prediction Center (CPC), under the National Weather Service (NWS) and National Oceanic and Atmospheric Administration (NOAA), prepares forward looking climate predictions on temperature and precipitation. The following information comes from the CPC Three-Month Outlooks Official Forecasts.[23]

As of mid-April, El Niño conditions are still observed, but Pacific Sea surface temperatures are cooling rapidly. By the end of July, El Niño conditions are expected to transition to neutral conditions with 85 percent likelihood and may transition to La Niña conditions later this year. A transition from El Niño potentially means relatively warmer and drier weather in the southern half of California.

Normal precipitation levels are expected in California through July, which means relatively little rain in most of the state. In the transition to fall, the precipitation outlook is also normal for most parts of the state, with moderate chances for the eastern desert areas having lower than average precipitation. Currently, all of California is drought free.

Normal temperatures are expected in the coastal areas of California, Oregon, and Washington through October. Moderately above-normal temperatures are expected in the inland areas of the coastal states and solidly above-normal temperatures in the rest of the Western Interconnection. The inland areas of California range from 33 percent to 60 percent chances for above-normal temperatures. Figure 10 shows the CPC Seasonal Temperature Outlook for July, August, and September. The CPC maps covering October show a similar pattern of temperature probabilities.

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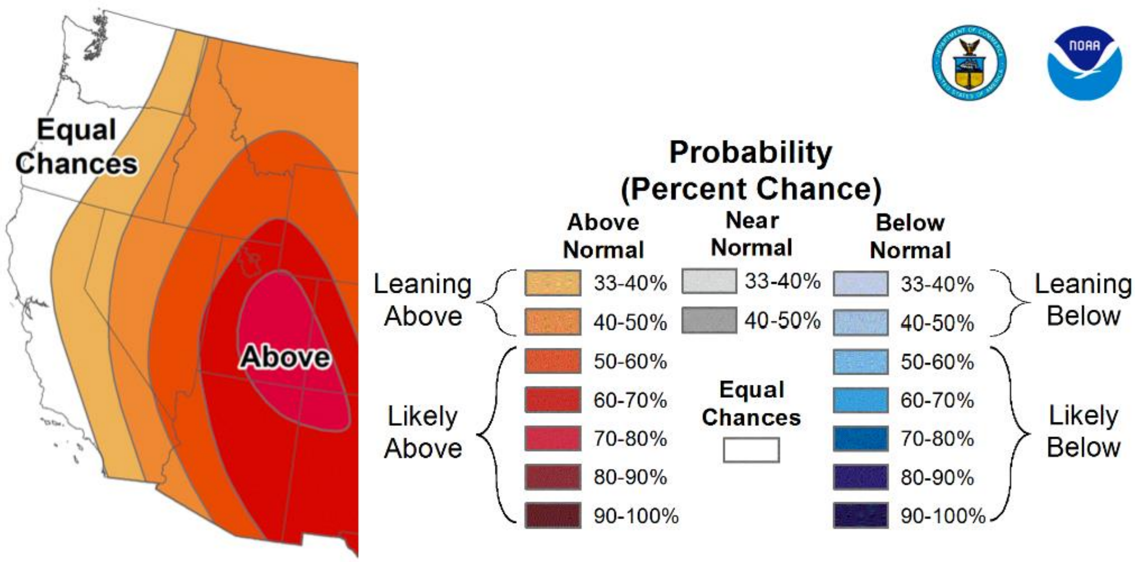
23 CPC *Three-Month Outlooks Official Forecasts* can be found at:
https://www.cpc.ncep.noaa.gov/products/predictions/90day/

Figure 10: CPC Seasonal Temperature Outlook for July, August, and September



Source: CPC Seasonal Temperature Outlook Valid July-August-September 2024

Wildfire Risk

The Wildfire Forecast & Threat Intelligence Integration Center (WFTIIC) serves as California's central organizing hub for wildfire forecasting, weather information, threat intelligence gathering, analysis and dissemination, and prepares a monthly four-month outlook.[24]

The current WFTIIC four-month outlook expects areas of normal and above-normal potential for wildfires in July, August, September, and October.[25] Through September, Oregon and Nevada include areas of above-normal fire potential traversed by the California-Oregon Intertie and the Pacific DC Intertie, the two critical north-to-south hydro import paths into California. The WFTIIC potential is relative to the month and location. and many areas are prone to wildfires in the summer and fall, so destructive fires can still occur in normal or below-normal conditions.

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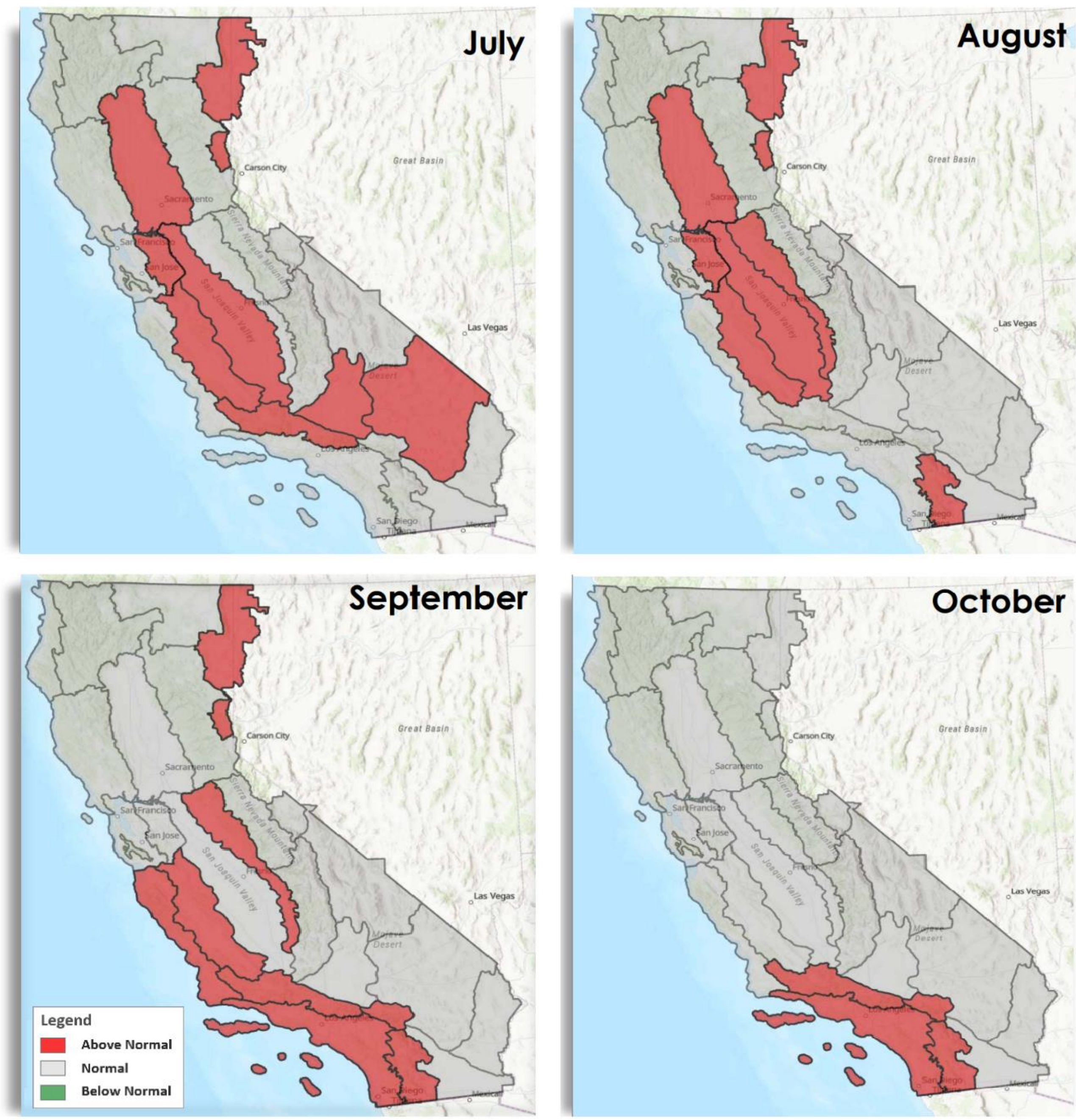
24 WFTIIC information can be found here: https://hub.wftiic.ca.gov/

25 The *WFTIIC four-month outlook* can be found at: https://hub.wftiic.ca.gov/pages/four-month-outlook

Figure 11: WFTIIC Significant Wildfire Potential for July – October 2024



Source: WFTIIC Four Month Outlook July – October 2024

California Hydroelectric Conditions

Whereas, the northwest is having a challenging year with hydroelectric resources, California is in a better position. April is generally considered a critical month for forecasting hydroelectric conditions as it historically signifies the peak snowpack for the season and marks the transition to spring snowmelt into the state's rivers and reservoirs. The April 2024 readings from the

DWR showed that the statewide snowpack snow-water equivalent was 110 percent of the April 1 average, a significant improvement from just 28 percent of average on January 1, 2024.[26]

Efforts to capture and store water are ongoing, with the State Water Project increasing storage at Lake Oroville and San Luis Reservoir since January 1, 2024. Recently, the State Water Project increased its forecasted allocation of water supplies for the year to 30 percent, up from an initial 10 percent, due to the storms in February and March. However, uncertainty about the spring runoff and ongoing pumping restrictions to protect threatened and endangered species, such as steelhead trout, in the Delta has impacted that allocation forecast. The uncertainty about the spring runoff and ongoing pumping restrictions are new challenges that surfaced this year and were not present in 2023, when the state achieved 100 percent water allocation for the first time since 2006. This directly translates to less energy consumption due to water pumping, down to less than one-third of the maximum pumping capacity of 11,000 cubic feet per second, throughout the State Water Project and Central Valley Project.

Despite the positive snowpack news, variability in climate conditions emphasized the importance of conservation and efficient runoff management. While California's reservoirs stood at 116 percent of average as of April 2, 2024, challenges such as a dry start to the year and potential impacts from burn scars may have led to below-average spring runoff and affected water availability.

New California Resources

In recent years, California has seen a remarkable uptick in energy storage deployment. The data for 2023 alone show the addition of 2,529 MW of energy storage nameplate capacity, with a cumulative total of 6,240 MW between 2020 and 2023 (Table 1). Analysts estimate[27] that the significant investments in new generation and storage infrastructure over the 2022–2023 calendar years, largely driven by CPUC IRP requirements, have amounted to a $7 billion influx into California's energy infrastructure. Much of this development has been concentrated in Southern California, particularly in Riverside, San Bernardino, and Kern Counties, where ample solar and wind resources offer favorable conditions for synergistic pairing with energy storage technologies.

Strategic deployment of new resources has capitalized on existing grid infrastructure, minimizing costs for ratepayers. Noteworthy examples include the integration of energy storage capacity near natural gas facilities in Moss Landing which took advantage of pre-existing grid infrastructure.

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26 California Department of Water Resources, *April Snow Survey Shows Above Average Snowpack for Second Straight Season*, available at: https://water.ca.gov/News/News-Releases/2024/Apr-24/April-Snow-Survey-Shows-Above-Average-Snowpack-for-Second-Straight-Season

27 Yee Yang, Chie Hong (California Energy Commission), and Sarah Goldmuntz (California Public Utilities Commission). May 2024. *Joint Agency Reliability Planning Assessment Covering Requirements SB 846 First*, https://www.energy.ca.gov/publications/2024/joint-agency-reliability-planning-assessment-covering-requirements-sb-846-first.

The trend toward large-scale projects deployed in phases has also emerged, as seen in projects like the Daggett Solar and Storage project, which rolled out gradually from July 2023 to December 2023. In addition, the procurement of resources from neighboring states has contributed to diversifying California's energy portfolio, with more than 800 MW of New Mexico wind added in 2021 and new solar and storage resources from Nevada coming on-line in 2023. This trend is poised to gain momentum with increased transmission connections, both planned and in-development, promoting greater out-of-state procurement in the foreseeable future.

Table 1: Cumulative New Resource Additions, in 2023 and for January 2020 Through December 2023

Technology Type	Nameplate Capacity (MW)	Number of Projects	Nameplate Capacity (MW)	Number of Projects
	2023	2023	2020-2023	2020-2023
Storage	2,529	34	6,240	84
Solar	2,482	36	5,743	83
Hybrid (Storage/Solar)	470	6	1,386	21
Wind	178	2	878	21
Geothermal	-	0	41	1
Biomass, Biogas, Hydro	5.4	2	39	10
SubtotalNew SB100 Resources, California ISO	5,665	80	14,326	220
Natural gas, incl. Alamitos & Huntington Beach	-	0	1,477	12
Total New Resources, California ISO	5,714	80	15,803	232
New Imports, Pseudo-Tie or Dynamically Scheduled	50	1	1,739	14
Total New Resources, including Imports	5,764	81	17,542	**246**

Source: CPUC staff, California ISO OASIS

As shown in Table 2, there is a significant amount of resources expected by the start of summer 2024 with various resources scheduled to come on-line throughout the summer.

Table 2: California ISO Queue Cumulative Expected Resources (in MW) as of April 19, 2024

Resources	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Battery Storage	10	315	645	1,185	1,745	2,119	2,576	3,118	3,913	4,239	4,382	5,142
Geothermal	0	0	0	0	0	0	0	0	13	13	13	13
Hydro	0	0	0	0	6	6	6	6	6	6	6	6
Natural Gas	0	0	0	48	48	48	103	108	108	108	108	108
Other	0	1	1	1	3	6	6	6	11	11	11	11
Solar PV	54	334	1,074	1,347	1,643	1,982	2,318	2,645	2,645	2,645	2,845	4,473
Wind	0	230	230	260	260	287	287	311	311	391	391	472
Actual Installed	127	357	1,206	1,713	-	-	-	-	-	-	-	-

Source: California ISO New Resource Interconnection

Status of Energy Storage

Battery energy storage continues to be a pivotal technology supporting the integration of renewable energy and providing capacity at peak demand. Specifically, energy storage can address the intermittency issues associated with solar and wind power by storing energy that might otherwise be curtailed and delivering that energy during periods of high demand. The rapid expansion of energy storage has occurred across residential, commercial, and utility sectors in California, providing grid stabilization, peak-shaving, and time-shifting capabilities.

Deployment of battery energy storage in California has grown significantly over the past few years. At the start of 2021, California had 1,475 MW of installed storage capacity, with 850 MW at the grid level and 625 MW installed behind-the-meter. Three years later, on April 25, 2024, Governor Newsom announced that California had reached a major storage milestone: surpassing 10,000 MW of installed battery energy storage capacity. Of the current 10,500 MW installed, about 8,900 MW is utility-scale storage, with the remaining 1,600 MW as behind-the-meter.

Of note is the dramatic increase in the number of behind-the-meter installations in the residential and commercial sectors. It is estimated that there are more than 154,000 behind-the-meter battery energy storage systems installed across the state.

Resource Adequacy

In 2022, the RA market faced challenges driven by various factors.[28] Total committed RA resources fluctuated throughout the year, ranging from 30,845 MW to 48,068 MW, reflecting monthly variations in RA obligations tied to expected peak loads. While individual LSE bilateral contracting constituted a significant portion of forward capacity procurement, centralized procurement allocations to all LSEs, and capacity from resources like Capacity Allocation

28 California Public Utilities Commission, Energy Division. May 2024. *2022 Resource Adequacy Report*, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2022-ra-report_05022024.pdf.

Mechanisms, Reliability Must-Run, and DR, also contributed to meeting RA obligations. However, increasing prices for RA, particularly during summer months, posed significant concerns. The weighted average price of both local and system RA showed considerable increases compared to 2021, with system RA prices surpassing local RA prices for the first time.

Moreover, noncompliance issues were prevalent, leading to the issuance of citations and enforcement actions by the CPUC's Enforcement Division. In 2022, 18 citations were issued for 85 violations related to compliance, totaling nearly $11 million in penalties. The citations briefing revealed that various types of entities, including community choice aggregators (CCAs), energy service providers, and IOUs, faced citations, indicating widespread challenges in meeting RA requirements across different sectors of the market.

CalCCA is a consortium of 25 operational CCA programs in California representing communities that join together to pool their electricity load to purchase clean energy and develop local projects and programs on behalf of their residents and businesses. CalCCA identified several factors contributing to a tight RA market.[29] These factors include increasing demand, higher PRMs, and the retirement of certain resources like once-through cooling plants. While new capacity deployment may help, delays are expected in the build out. Moreover, the RA market is undergoing a significant design shift toward a 24-hour approach from 2025 onward.

In April 2023, the CPUC finalized RA reforms through Decision D.23-04-010, adopting implementation details for the 24-hour slice of day (SOD) Framework. Under the SOD framework, LSEs must demonstrate capacity adequacy for their gross load profile, including PRMs, across all 24 hours on the "worst day" identified by the California ISO. This decision outlined compliance tools, resource counting rules, and methodologies for translating PRMs into the SOD Framework. On February 5, 2024, CPUC released a report on RA SOD Implementation and Year Ahead Showings.[30] The final decision was issued for Track 1 implementation on June 26, 2024.

Western Interconnection

The California electric system operates within a larger interconnected electricity system, known as the WI, linking the grid infrastructure across all, or parts, of 14 western states, two Canadian provinces and northern Baja, Mexico. This larger system collectively supports the reliability of each of 37 participating balancing authorities through information sharing and coordinated operations. California is a net importer of electricity, making the outlook of the WI as a whole of particular importance for California reliability.

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29 California Community Choice Association (CalCCA), *CalCCA Stack Analysis 2023-2026 Updated*, available at: https://cal-cca.org/wp-content/uploads/2024/02/CalCCA-Stack-Analysis-2023-2026-updated-01_16_24-.pdf.

30 California Public Utilities Commission, *Energy Division Report on RA SOD Implementation and Year Ahead Showings*, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/energy-division-report-on-ra-sod-implementation-and-year-ahead-showings.pdf.

Western New Resource Outlook for Summer 2024

In the WI, there are 25.5 GW of resources proposed to come on-line in 2024 and about 3.1 GW of planned retirements (Table 3).

Table 3: WECC 2024 by Resources Fuel Type

Tier 1 Additions by Fuel Type	MW	CANADA	CA/MEXICO	NORTHWEST	SOUTHWEST
BESS	7,304	80	4,397	1,130	1,697
Fuel Oil	644	-	644	-	-
Geothermal	45	-	-	45	-
Hydro	382	382	-	-	-
Nat Gas	5,946	2,832	232	2,784	99
Solar	8,540	1,392	2,440	2,967	1,742
Wind	2,611	1,106	-	1,289	216
Total	**25,473**	**5,791**	**7,713**	**8,215**	**3,754**
Retirements by Fuel Type	**MW**	**CANADA**	**CA/MEXICO**	**NORTHWEST**	**SOUTHWEST**
Coal	-920	-820	-	-100	-
Geothermal	-4	-	-	-4	-
Hydro	-447	-	-	-447	-
Nat Gas	-479	-	-326	-153	-
Nuclear	-1,150	-	-1,150	-	-
Other	-45	-	-	-45	-
Solar	-30	-	-	-30	-
Total	**-3,075**	**-820**	**-1,476**	**-779**	**-**

Source: WECC staff, note 1,150 MW nuclear retirement included prior to NRC approval for continued operation at DCPP

Between January and July 2023, about 38 percent of the proposed capacity additions reported to WECC achieved commercial operational status. If the same percentage is applied to the 2024 proposed capacity, significantly less than the proposed new capacity will achieve commercial operating status by the upcoming summer. BAs across the WI reported supply chain issues as a significant factor contributing to the gap between proposed and operational capacity in 2023 and remains a reliability concern.

Summer 2024 Probabilistic Analysis

The WECC uses the Multi-area Variable Resource Integration Convolution (MAVRIC) model to conduct probabilistic analysis for the WI. For summer 2024, resources across the area are projected to be sufficient to support normal peak demand. However, it is projected that wide-area heat or other extreme events could expose areas of California/Mexico, to energy supply shortfalls. These events are projected for the hours after peak and under extremely stressed conditions. It should be noted, these shortfall events are not projected for the California footprint area of this region but specifically in the Mexico portion of this region.

In addition to the WECC MAVRIC model, the NERC Reliability Assessment notes that Western areas rely on regional transfers to meet demand at peak and the late afternoon to evening hours, particularly as energy output from the area's solar photovoltaic (PV) resources decline. Under normal operating conditions in the WECC, sufficient transfer capability is projected. However, under above normal demand conditions, the WECC has the potential for insufficient operating reserves. Wildfire risks to the transmission network, which often accompany these above- normal, area-wide heat events, can limit electricity transfers and could result in localized load shedding.[31]

Western Fuel Supply Outlook for Summer 2024

Stored supplies of natural gas and coal are at adequate levels, but the industry is monitoring for potential generator fuel delivery risks. Most BA reports of fuel supply issues have dropped significantly from the previous year.[32] However, LADWP has reported challenges in arranging coal deliveries due to mine closures and transport delays. These challenges are causing LADWP to conserve its coal supply for the summer peak months.

Natural gas and coal prices show a trend that could encourage more natural gas consumption in the WECC for summer 2024 compared to summer 2023.[33]

Western Water and Wildfire Outlook for Summer 2024

During California peak demand, imported power is essential. Some of these imports consist of hydroelectric power fed by reservoirs in the north and southwest regions of the WECC and over transmission lines located in high-risk wildfire regions. Most major reservoirs across the WI appear to show an increase in water levels year over year. Lake Mead and Lake Powell for example, show an approximate 10 percent increase in reservoir storage volume from 2023 to 2024.[34] However, both Lake Mead and Lake Powell are still well below historical averages.

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31 U.S. Energy Information Administration. "U.S. Coal Consumption by End-Use Sector," https://www.eia.gov/coal/production/quarterly/pdf/t32p01p1.pdf.

32 Shepardson, David and Nandita Bose. December 22, 2022. "Biden Signs Bill to Block U.S. Railroad Strike.," Reuters, https://www.reuters.com/world/us/biden-signs-bill-block-us-railroad-strike-2022-12-02/.

33 U.S. Energy Information Administration. *"Henry Hub Natural Gas Spot Price, "* https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

34 U.S. Bureau of Reclamation. "*Reservoir Conditions*," https://data.usbr.gov/visualizations/reservoir-conditions/.

Much of Western Canada remains in some level of drought. Exceptional and extreme drought conditions are present in Alberta; however, hydroelectric resources are minimal in this region, and therefore, the drought is not a concern for summer reliability. Much of British Columbia is in drought conditions as well, ranging from exceptional to severe.[35] Abnormally high temperatures and below normal snowpack create concerns for a dry summer and increased wildfire frequency.[36] The drought in British Columbia is a reliability concern as close to 90 percent of the region's capacity is derived from hydroelectric resources.[37]

The 2024 Seasonal Drought Outlook[38] for the United States projects persisting and developing drought conditions across the Northwest. Reservoirs in the Northwest have been returning to normal, but significantly below-average snowpack was observed in Montana, Washington, Idaho, and Wyoming at the end of February 2024. Moderate drought conditions are also expected to last into the summer for Arizona and New Mexico, but drought is persisting and developing in areas.[39] California remains mostly drought free, with some persisting drought in far northern California.

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35 U.S. Drought Monitor, *What is the U.S. Drought Monitor?*, available at: https://droughtmonitor.unl.edu/About/WhatistheUSDM.aspx#:~:text=The%20map%20uses%20six%20classifications,Exceptional%20Drought

36 National Interagency Coordination Center. March 14, 2024. *National Significant Wildland Fire Potential Outlook*, https://www.nifc.gov/nicc-files/predictive/outlooks/NA_Outlook.pdf.

37 North American Electric Reliability Corporation. December 2023. *2023 Long-Term Reliability Assessment,* https://www.nerc.com/pa/RAPA/ra/Reliabilitypercent 20Assessmentspercent 20DL/NERC_LTRA_2023.pdf.

38 National Weather Service, Climate Prediction Center, US Seasonal Drought Outlook, March 31,2024 https://www.cpc.ncep.noaa.gov/products/expert_assessment/sdo_summary.php

39 National Centers for Environmental Information. January 2024. "*North American Drought Monitor — January 2024*," https://www.ncei.noaa.gov/monitoring-content/temp-and-precip/drought/nadm/maps/narr/nadm-narr-202401.pdf; National Center for Environmental Information, "*North American Drought Monitor - February 2024*," February 2024, https://www.ncei.noaa.gov/monitoring-content/temp-and-precip/drought/nadm/maps/narr/nadm-narr-202402.pdf.

CHAPTER 5:
Electric Reliability Analysis

This chapter provides the electric reliability analysis for summer 2024 and through 2030. California is projected to meet system reliability standards through 2030 even with a 40 percent reduction in planned resources. For summer 2024, there may be a need for contingency resources under a 2022 equivalent extreme heat event if there are delays to projected new battery resources or if there is a coincident wildfire impacting transmission.

The CEC utilizes two methodologies that provide different, but valuable, perspectives on the reliability outlook. A loss-of-load expectation, or RA analysis, determines whether a forecasted resource build is projected to have a maximum of 1 day with loss of load in 10 years using a probabilistic analysis. This is widely considered the industry standard for RA planning and is utilized for near-term to long-term planning. RA allow resource planners and policy makers to determine whether enough resources are being planned for or procured. A resource stack analysis is also used to evaluate the potential need for contingency resources under a variety of conditions. A stack analysis can capture specific circumstances that may not be under the control of resource planners and policymakers, such as extreme weather events and resource delays, to inform contingency planning and is best utilized for near-term planning.

Resource Stack Analysis

The section provides a high-level overview of the Resource Stack Analysis, as described by the CEC's Summer Stack Analysis for 2022-2026[40] and past SB 846 Joint Agency Reliability Planning Assessment quarterly reports.[41] This approach is a deterministic analysis spanning near-term horizons, with a focus on the peak summer months, July to September. The analysis compares anticipated supply against projected demand, incorporating a 17 percent PRM, equivalent to the current RA planning standards for CPUC-jurisdictional entities.

Updated Resource Stack Analysis for Summer 2024

As shown in Table 4, there are changes to the resource stack since the release of the SB 846 *May 2024 First Quarterly Report*,[42] which focuses primarily on California ISO balancing area. Notably, there was 966 MW of NQC added to the resource stack. The 966 MW of new NQC consists of existing resources that are shown for more NQC MWs than the prior report, new standalone battery, new hybrid, and new solar resources that have come online in quarter one of 2024. These are MW that will now be available to support summer net peak demand and

40 California Energy Commission, *2022 Summer Stack Analysis Update*, available at: https://www.energy.ca.gov/publications/2021/2022-summer-stack-analysis-update.

41 California Energy Commission, *Summer Reliability*, available at: https://www.energy.ca.gov/data-reports/california-energy-planning-library/reliability/summer-reliability.

42 California Energy Commission, available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=256229&DocumentContentId=92014.

ensure system reliability. The effect of adding 966 MW of NQC can be seen in the need for contingencies.

In the *May 2024 First Quarterly Report*, surpluses of 4,000 MW and 1,500 MW were reported under average conditions and 2020 equivalent event conditions, respectively. However, there was a 90 MW need if the state were to experience conditions equivalent to a 2022 event. Table 4 shows the resource stack analysis identified improvements from the average conditions through all extreme events.

While improvements can be seen in all conditions, it is important to note that improvements are forecasted results based on the assumed full build-out of resources planned before September 2024. More specifically, the resource stack analysis in this report assumes that 3,118 MW of battery storage will come online before August 31, 2024, to support reliability in the month of September. Any delays to the battery storage build-out could create challenges under extreme events.

Table 4: Comparison of Projected Resources to Meet 2024 September Peak

	2024 1st Quarter Report	2024 2nd Quarter Update	Change Since Last Update
Supply (MW)			
Demand Response	1,115	1,052	▼63
Existing Resources	43,556	44,522	▲966
New Batteries*	3,327	3,118	▼209
Wind	1,382	1,382	–0
Solar	1,643	1,706	▲63
RA Imports	6,000	6,000	–0
Total	**57,022**	**57,779**	**▲757**
Demand (MW)			
2023 CEC Demand Forecast – 2024 Sept. Peak Demand	45,972	45,972	–0
Surplus/Shortfalls (MW)			
Average Conditions - Planning Standard	4,000	4,840	▲840
2020 Equivalent Event	1,500	2,330	▲830
2022 Equivalent Event	-90	730	▲820

*Decrease in this category means that resources have come online or have an updated online date but generally means they are no longer considered new and have been moved to Existing Resources.

Source: CEC staff with California ISO data

CEC quantifies the risk of delays in new resources coming online, because historically, the state has experienced resource delays due to supply chain, interconnection, and permitting. Table 5 shows the impact of 20 percent and 40 percent resource delay to the need for contingencies. The delay percentage is applied across all resources but solar and wind contributions to reliability at net peak are fairly minor. Therefore, the biggest new resource supporting reliability is battery storage. A 40 percent delay to new battery storage resources could swing a 2022 equivalent event system condition from a 730 MW surplus (Table 4) to a 700 MW (Table 5) need for contingency resources.

Table 5: Impact of Planned Resource Build-Out Delays on Reliability

New Capacity Delay	Battery capacity online by 8/31/2024	System conditions	System Surplus/Shortfall
20 percent	2,494 MW	2022 equivalent event	0 MW
40 percent	1,870 MW	2022 equivalent event	-700 MW

Source: CEC staff

Developing a Statewide Resource Stack Analysis

While past resource stack analyses have focused on the California ISO balancing area only, this report seeks to understand the supply and demand balance across the state under various conditions. While future analyses will include all loads across the state, the expanded resource stack analysis used in this report incorporates the three largest POUs – LADWP, IID, and SMUD – in addition to the California ISO. These three utilities make up the largest utilities by load outside of the California ISO Balancing Area, cumulatively serving over 10 GW[43] of customer peak demand. Using the electric resource plans submitted to the CEC in 2022, the resource stack analysis added the reported supply capacity for these three utilities on top of the existing California ISO resource stack.

For the planning standard case, the total demand plus 15 percent PRM, for LADWP, IID, and SMUD, were added to the California ISO peak demand plus 17 percent PRM. Due to the differences in PRMs, the summation of demand is done after the PRM is applied. Figure 12 compares the resource stack to a 2020 (orange trend line) and a 2022 (yellow trend line) equivalent event demands. The equivalent event demands are defined in Table 6.

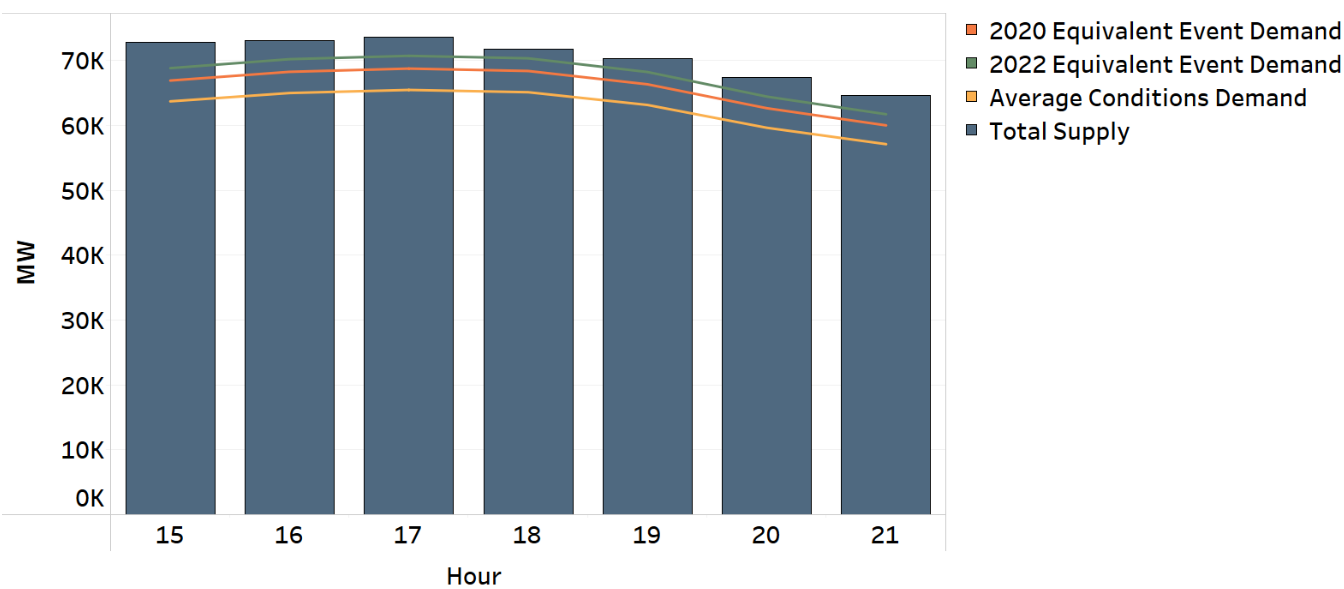
43 California Energy Commission, *Utility Plans 2022*, available at: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/utility-plans-2022.

Table 6: System Planning Reserve Margin Assumptions

Condition Relative to 1-in-2 Forecast	Operating Reserves	Outages	Demand Variability	Coincidental Fire Risk	Notes
Average Conditions: Current RA Planning Standard – 17%	6%	5%	6%	4,000 MW	
2020 Equivalent Event: Additional capacity needed to ride-through heat event like 2020	6%	7.5%	9%	4,000 MW	9% higher demand over median, and 2.5% higher levels of outages
2022 Equivalent Event: Additional capacity needed to ride-through heat event like 2022	6%	7.5%	12.5%	4,000 MW	12.5% higher demand over median, and 2.5% higher levels of outages

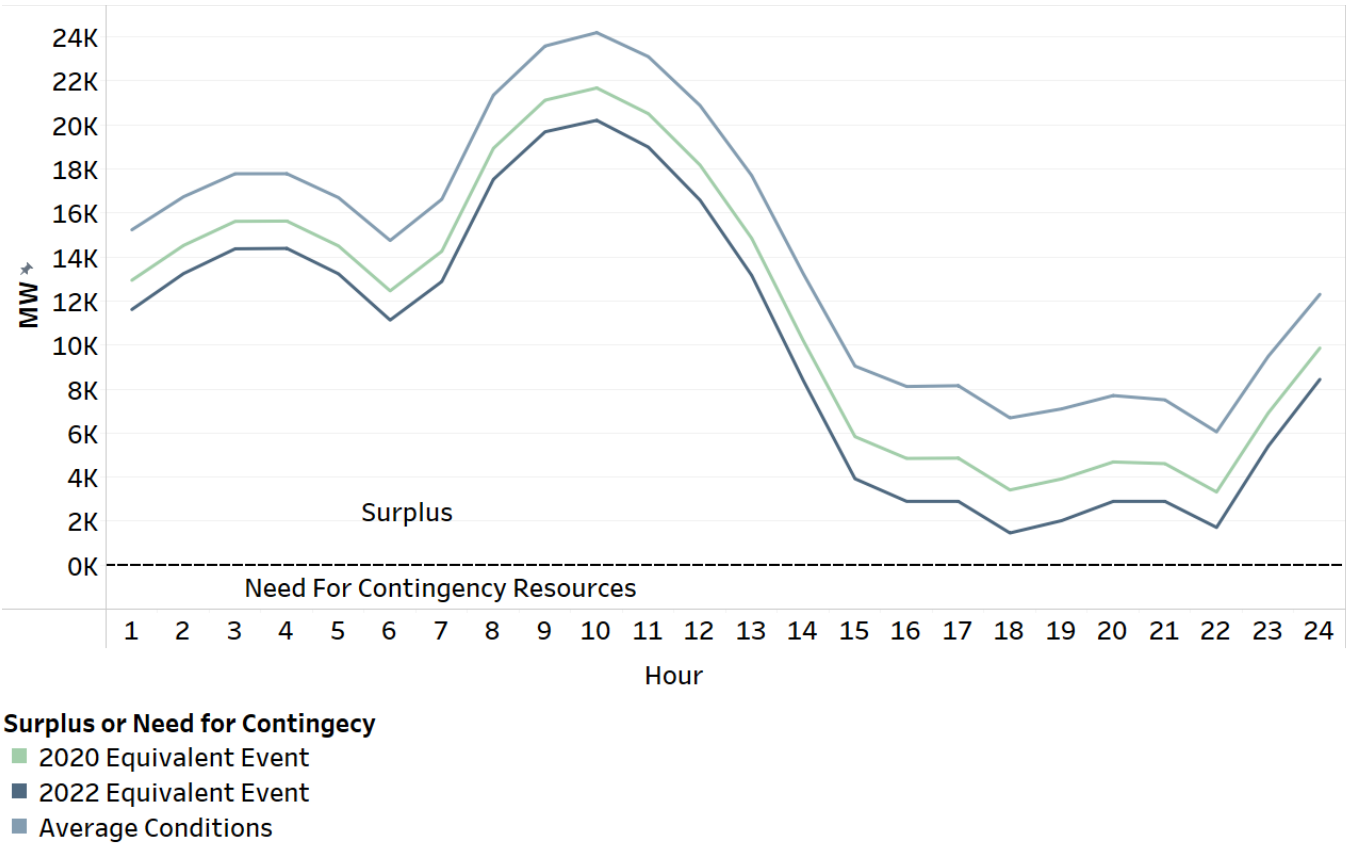
Source: CEC Staff – 1/20/2023 Lead Commissioner Workshop

Figure 12: 2024 September Expanded Resource Stack



Source: CEC Staff with California ISO Data and supply forms

Figure 13: 2024 September Surplus Above Planning Reserve Margins



Source: CEC Staff with California ISO Data

As seen in Figure 13, there is an excess of resources available to serve the customer load in California ISO, LADWP, IID, and SMUD areas. Figure 13 shows the magnitude of 6,700 MW surplus available during the most challenging hour in September under average conditions. July and August show a similar pattern of surplus during the net peak period. However, under extreme events, the surpluses reduce to 3,400 MW (2020 equivalent event) and 1,400 MW (2022 equivalent event). The addition of these three utilities to the resource stack analysis provides a more complete picture of the statewide reliability situation. The situation is positive under extreme events, which creates greater opportunities for coordination among balancing areas within California.

While the resource stack analysis may provide insights on system conditions at this point in time, the actual conditions that materialize in real-time may differ from actual projections in this analysis. Furthermore, the expected new resources available by the start of each summer month may also differ due to factors such as delays, construction, weather, permitting, and extended interconnection outages.

Loss of Load Expectation (LOLE) Analysis

The CEC completed a probabilistic assessment of the reliability outlook from 2024 to 2030, consistent with the supply forecast in the adopted 2023 Preferred System Plan (PSP), released in CPUC Administrative Law Judge Ruling in February 2024.[44] The goal of this analysis is to determine if the state is projected to meet the reliability standard of 1 day of unserved energy in 10 years (0.1 LOLE) and identify risks that may impact the reliability of the resource portfolio. The CEC evaluated the system under a variety of import scenarios to understand the risk of reduced imports and evaluate the risk of limited energy availability. As described previously in this report, California is a net importer of electricity and is reliant upon imports to meet energy demands, particularly during peak hours. To assess vulnerability from reductions in imports, a series of progressively restrictive scenarios were evaluated: imports restricted during peak demand hours (5,425 MW at hours 15:00 – 21:00), imports restricted in all hours of the day (5,425 MW from hours 00:00 – 24:00), and no imports into California. These scenarios evaluate unserved energy caused by potential import constraints on the system, such as reduced import transmission capacity from wildfire or the impacts of import tightening across the West. Additionally, expansion resources within California were evaluated using both the full PSP buildout, as well as a 40 percent reduction in the proposed PSP to better understand the impact of reduced resource procurement.

Model

To evaluate the RA of California's power system under a variety of scenarios, an hourly chronological production cost simulation was conducted in the PLEXOS modeling software. The software is also utilized by other California entities for RA analysis, including the California ISO. This California RA model was developed using public information to the maximum extent possible, and was optimized for both runtime and accuracy, striving to capture the high-level constraints on the system. Profiles for renewable resources are developed from the National Renewable Energy Laboratory (NREL) weather data and adjusted based on plant characteristics and generating profiles.

Key Assumptions

The RA model used demand and renewable resource shapes generated from 15 historical weather years representing 2007 to 2021, with weather inputs to the model being linked to the corresponding year.[45] For example, 2015 energy demand is always coupled with 2015 wind and solar shapes thus ensuring the relationship between weather-driven loads and weather-driven generation remains consistent. The demand shapes are the same as used in CPUC staff modeling for the PSP. To generate hourly load profiles over the forecasted period,

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44 The 2023 PSP and related materials can be found on the CPUC's 2022-2023 IRP Cycle Events and Materials webpage here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

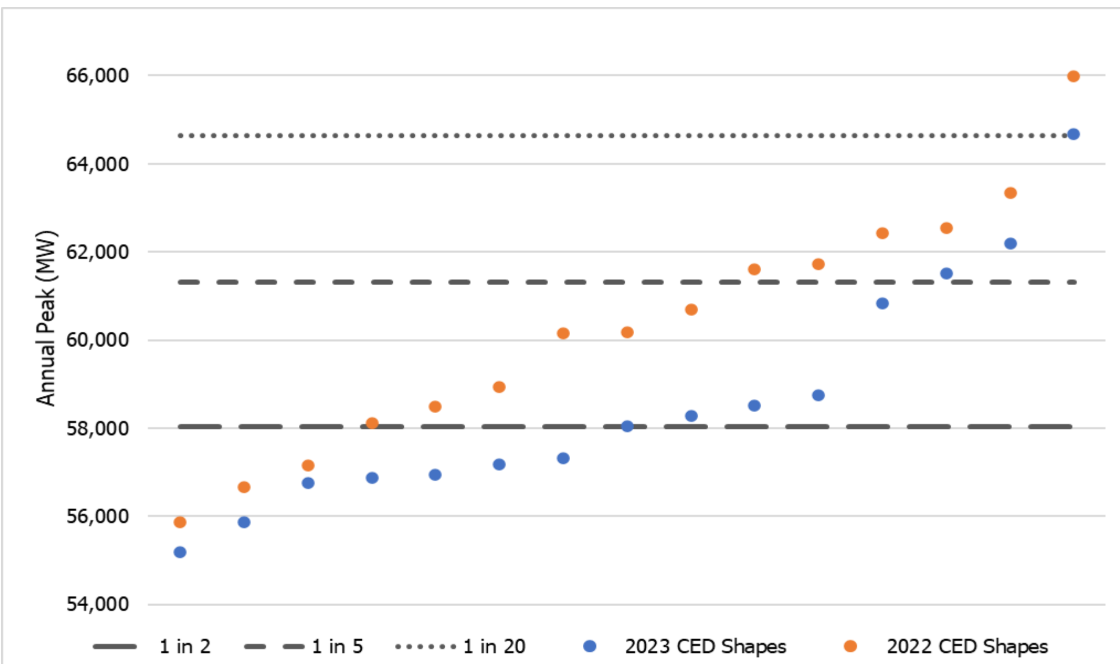
45 A shape for the 2021 weather year was not available so the demand shape for 2013 is modeled alongside 2021 wind and solar.

weather years were first scaled to the California Energy Demand Forecast (CED) and then load modifiers, such as energy efficiency and transportation electrification, were added.[46]

As of this report, the CPUC had not built new shapes based on the 2023 CED. Instead, CEC staff rescaled the CPUC shapes built for the 2022 CED to match the 2023 CED total annual energy and 1 in 20 peak forecasts, augmented by the 2023 CED load modifiers. Of note, the 1-in-20 peak forecast in the 2023 CED modeled in this report ranges from 500 to 2,000 MW lower between 2025 and 2032, as compared to the demands used to develop the 2023 PSP.

Figures 14 and 15 below show how the shapes in this report compare to the 2022 CED shapes used in PSP modeling and previous reliability reports and to the 1-in-2, 1-in-5, and 1-in-20 forecasts in the 2023 CED. Each dot represents the peak demand for each of the 15 weather years, and the dashed lines represent the 2023 peak forecasts. Across the board, the demands for the 2023 forecast are much lower than the 2022 forecast, with some weather years in 2022 reaching much higher peaks than the 1 in 20 forecast for the 2023 CED. The 2024 and 2030 modeled years are showcased below, as they represent the start and end of the modeled period.

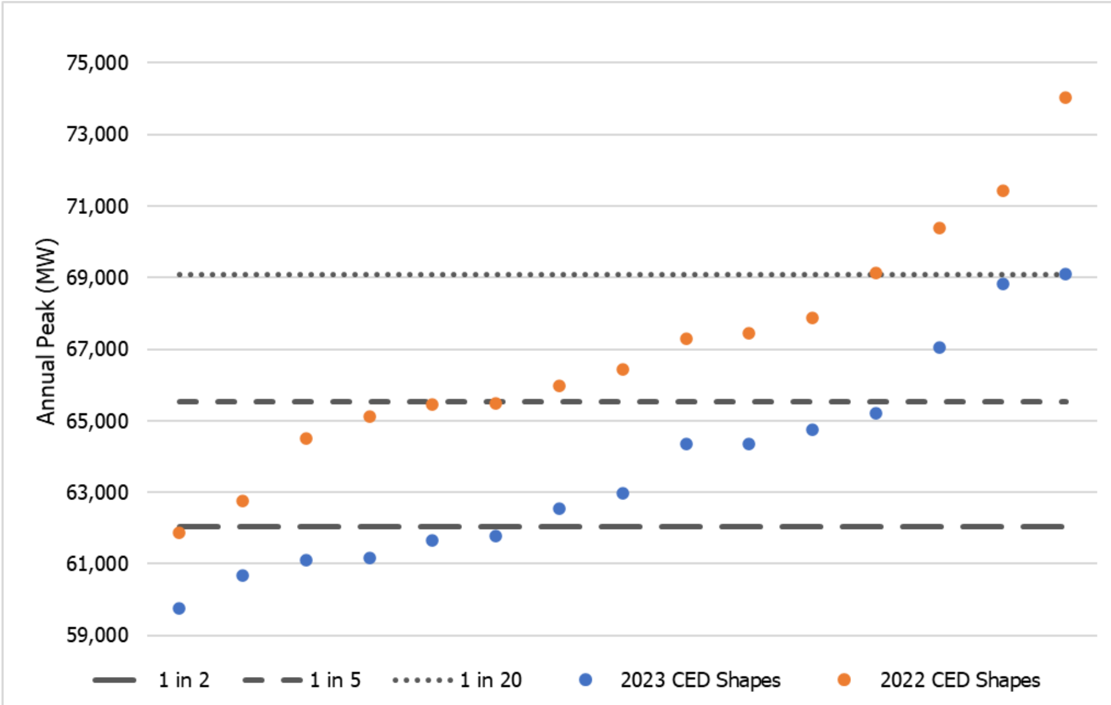
Figure 14: Peak Load Summary for Modeled Year 2024



Source: CEC Staff

46 Load modifiers do not vary by weather year.

Figure 15: Peak Load Summary for Modeled Year 2030



Source: CEC Staff

The model is California-centric, meaning power plants for the state are modeled in detail, but areas outside the state are represented as generic imports. Imports vary by scenario, but the default scenario limits imports during peak to 5,425 MW (4,000 MW of unspecified imports plus 1,425 MW of specified imports from Hoover Dam and Palo Verde) in California ISO and 8,524 MW for the state. The 8,524 MW limit was chosen based on historic import flows during summer peak hours between 2021 and 2023.

Loss of load results are reported for the state, although most outages occur in the California ISO region. Table 7 describes the data sources for the major inputs to the model.

Table 7: California RA Model Input Sources

Model Input	Data Source	Comments
Demand Shapes	CPUC Weather-Sensitive Load	Shapes based on 2022 CPUC shapes Energy scaled to 2023 Load modifiers from 2023 CED
Forced Outage Rates	NERC Generating Availability Data System	None
Plant Capacities	QFER	2022 QFER Data reported in 2023
Plant Heat Rates	QFER	None
Expansion Resources	Proposed CPUC 2023 PSP	Released in February 2024, Core Scenario (25 MMT by 2035)
Solar Shapes	NREL PV WATTS	None
Wind Shapes, 2007-2014	NREL WTK	Calibrated using actual monthly generation totals reported to EIA 923
Wind Shapes 2015-2021	Actual Generation Data from California ISO Subpoena	Aggregated by Wind Resource Area
Transmission Line Ratings	WECC Path Limits	None
Hydroelectric Monthly Energy Budget	EIA 923	None
OTC[47] Retirements	California ISO Announced Retirements and Mothball List	Assumed to be retired in 2023 for all scenarios
DCPP Retirement		Assumed online for all scenarios

Source: CEC Staff

All expansion resources for both California ISO and non-California ISO regions were sourced from the CPUC adopted 2023 PSP released in February 2024. Expansion resources include both in-development resources already under contract and generic resource additions generated from the CPUC's capacity expansion modeling using the RESOLVE modeling platform. Figure 16 shows the expansion resources slated to come online in both non-California ISO and California ISO regions of California.

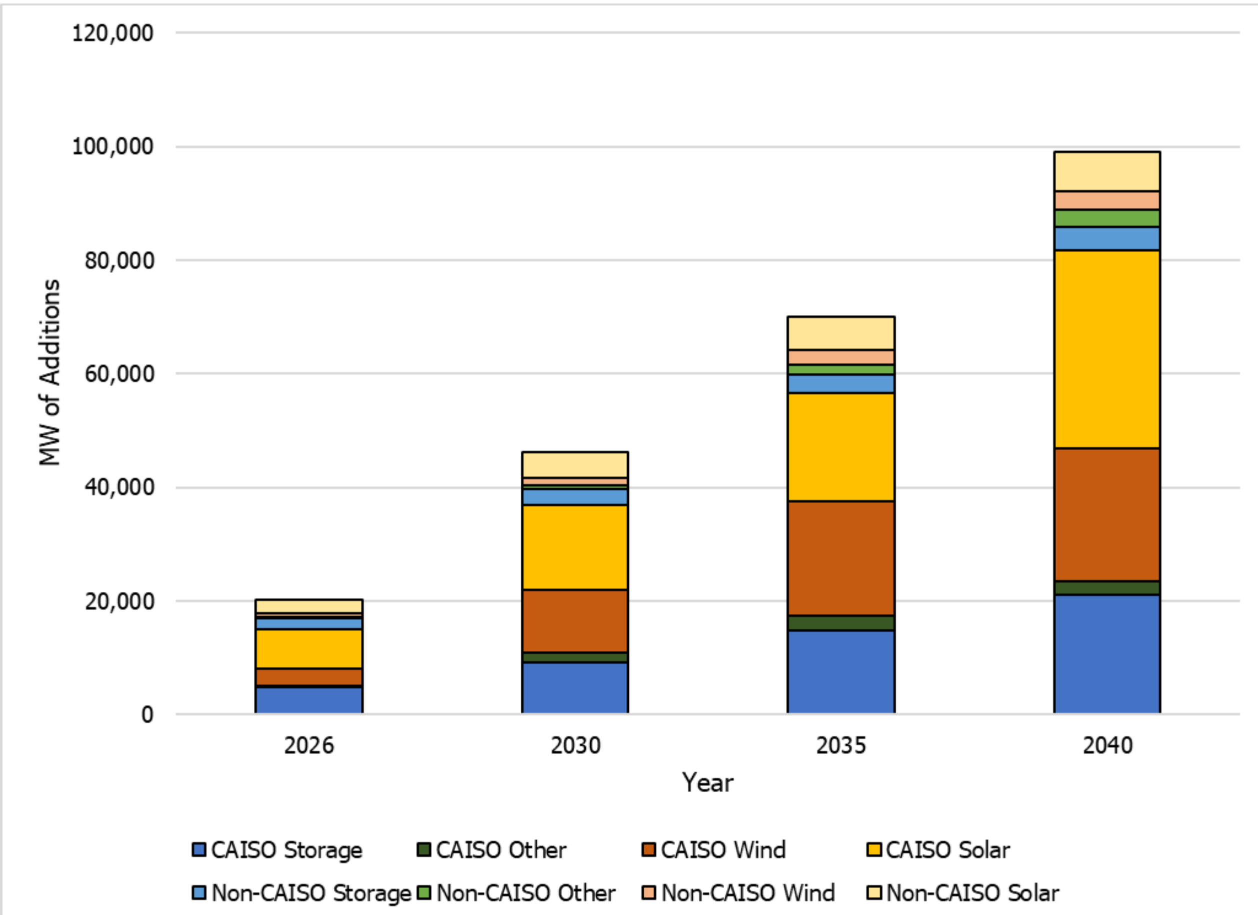
For the 40 percent Reduction scenario, both the in-development and generic resources are reduced by 40 percent. Most of the in-development resources in the model are located outside the California ISO and sourced from utility IRPs. The 40 percent Reduction scenario is intended to assess whether the system can maintain reliability even with resources well below what is projected, and does not imply that a 40 percent reduction in the PSP is likely.

The PSP resource build is driven primarily by the need for new zero-carbon and renewable resources to meet GHG reduction targets and exceeds minimum electric reliability standards.

47 once-through cooling

As previously discussed, the PSP was built for the 2022 CED forecast, which projected higher demands through the 2020s. Additionally, Diablo Canyon Power Plant (DCPP) was not included in the PSP, but has been included in all CEC model runs based on NRC approval for continued operation. The combination of these factors contributes to high levels of surplus, which was a primary driver in selecting extreme scenarios to study, such as 40 percent reduction and no imports. Milder scenarios including delaying instead of reducing resources were considered, but would provide minimal insight, as no unserved energy would be modeled.

Figure 16: Total Resource Additions in PSP



Source: CEC Staff

Table 8 provides additional detail on the level of resources described as generic versus in-development. No generics were added to non-California ISO regions. Most of the resources in the PSP are generic RESOLVE additions and not currently under development.

Table 8: Resource Additions for Generic and In-Development (MW)

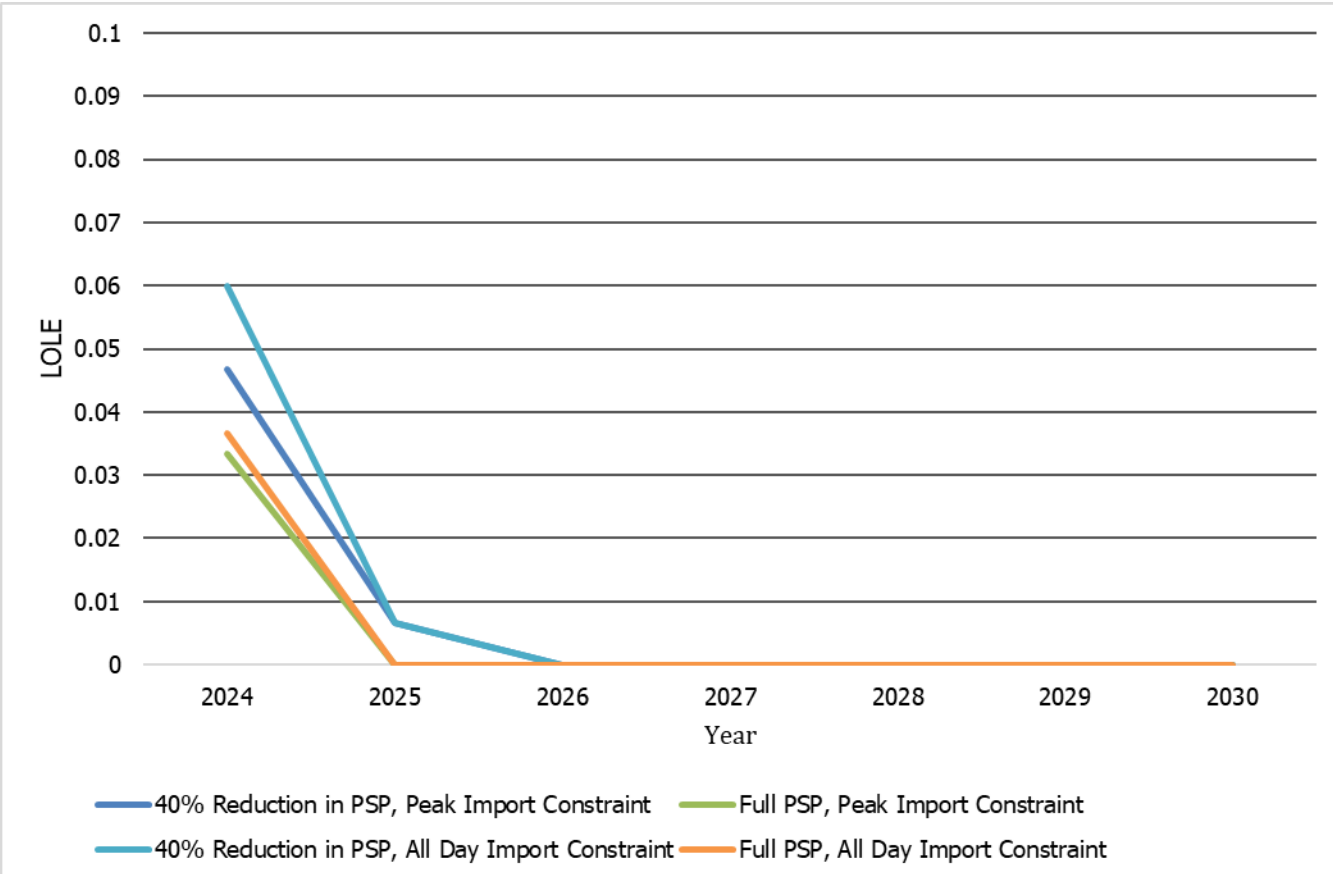
Category	2026	2030	2035	2040
California ISO Generic Other	288	1,779	2,405	2,405
California ISO Generic Solar	6,875	14,781	18,988	35,005
California ISO Generic Storage	4,603	9,001	14,730	20,932
California ISO Generic Wind	2,800	10,300	18,631	20,631
California ISO In-Development Other	0	0	0	0
California ISO In-Development Solar	0	0	0	0
California ISO In-Development Storage	151	151	151	151
California ISO In-Development Wind	289	773	1,673	2,673
Non-California ISO In-Development Other	292	618	1,715	3,103
Non-California ISO In-Development Solar	2,374	4,581	5,761	6,921
Non-California ISO In-Development Storage	1,957	2,933	3,203	3,973
Non-California ISO In-Development Wind	658	1,290	2,750	3,320
Total Statewide	20,287	46,207	70,007	99,114

Source: CEC Staff

Loss of Load Modeling Results

Both the PSP and the 40 percent Reduction scenarios are projected to exceed the 0.1 LOLE reliability target through 2030. There is minimal difference between scenarios with imports restricted only during peak and with imports restricted all day, indicating minimal energy constraints on the system. Both scenarios see a small amount of unserved energy in 2024 and 2025, with the 40 percent Reduction scenario extending to 2026, however, all values fall well below the 0.1 LOLE threshold. All unserved energy events occur at 18:00 in early September. Figure 17 shows the LOLE for each scenario in 2024 through 2030.

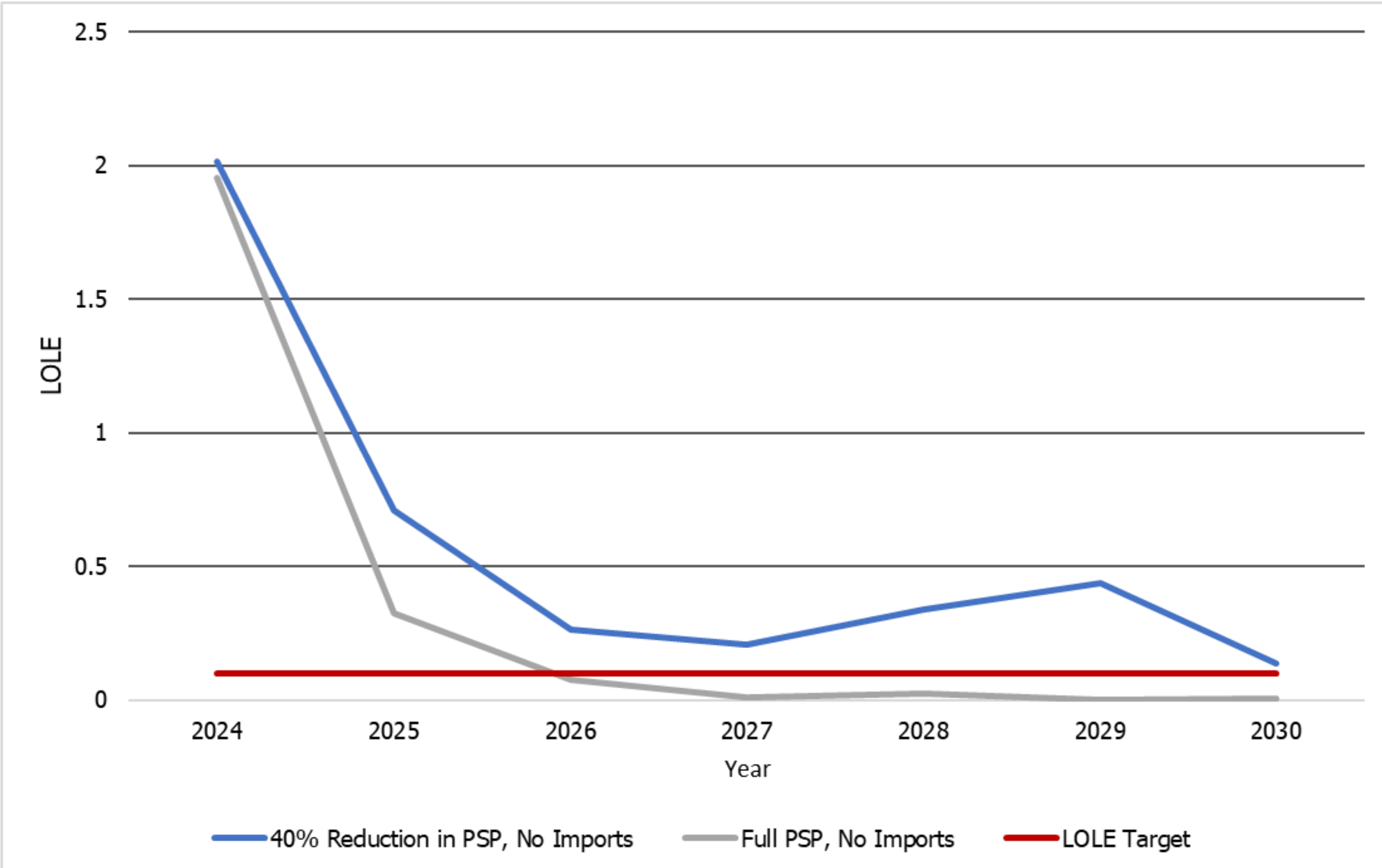
Figure 17: LOLE Across Core Scenarios



Source: CEC Staff

Figure 18 shows that in the No Imports scenario, minimum reliability standards are met from 2026 - 2030 while the 40 percent Reduction with No Imports scenario fails to meet reliability targets in all years.

Figure 18: LOLE Across No Import Scenarios



Source: CEC Staff

The purpose of the CEC probabilistic RA model is to assess if the planned resource build is sufficient to meet the CEC's reliability target of 0.1 LOLE. In each scenario, the electricity system is simulated under multiple weather and forced outage samples and checked for loss of load.

The resource build assessed in this report was the PSP, which was built under an earlier, higher demand forecast, and without an assumption that DCPP remains online past its previous planned retirement dates of 2024 for Unit 1 and 2025 for Unit 2. Even under those assumptions, the build does well exceed targets, and in the current analysis continues to well exceed reliability targets through the 2020s. The PSP is robust to a 40 percent reduction in every year, or no imports being available to California after 2026, but not both.

Probabilistic modeling is intended to assess whether planned resources are sufficient under reasonably foreseeable situations and doesn't take into account emergency conditions with low probability. For example, no demands higher than a 1 in 20 or transmission losses during wildfire are ever modeled in this analysis. Contingency resources may still be necessary under such circumstances.

CHAPTER 6: Extreme Event Preparedness

Compared to 2022, the reliability outlook was improved going into the summer of 2023. After a long drought, the especially wet 2022-2023 rainy season significantly improved the available capacity of the in-state hydroelectric generation fleet. New battery energy storage capacity also contributed to a better margin for extreme events. However, California still faced challenges during its net peak in late July 2023. Temperatures were milder in California compared to net peak 2022 but were still seasonably hot while extreme coincident temperatures were occurring elsewhere in the rest of the WI. This underscores the importance of preparedness for extreme events as climate change drives greater levels of uncertainty.

Coordinated planning and a high degree of communication continue to factor into the success of response to challenging grid conditions. This includes maintaining and operationalizing the California ISO's operational playbook, which fosters collaboration and communication with entities such as state agencies, load-serving entities, and other balancing authorities. In addition, the continued development of the SRR[48] ensures that programs are available for addressing reliability risks during extreme events.

Strategic Reliability Reserve

The SRR provides funding to secure conventional generation, capacity expansion at existing power plants, DR, distributed energy resources, and energy storage. The SRR consists of three programs, two are administered by the CEC, and one is administered by DWR. Table 9 shows online or expected capacity from each program for the 2024 summer months.

Table 9: Strategic Reliability Reserve Expected Program Capacity, Summer 2024

Strategic Reliability Reserve Program	July	August	September
DWR Electricity Supply Strategic Reliability Reserve Program	3,150	3,150	3,150
CEC Demand Side Grid Support	375	400	400
CEC Distributed Electricity Backup Assets	0	0	0

Source: CEC staff

- **Demand-Side Grid Support (DSGS) Program** offers incentives for electricity customers anywhere in the state to reduce load and dispatch backup generation with existing resources on an on-call basis. Some aspects of the program are similar to the CPUC's Emergency Load Reduction Program (ELRP), which is limited to customers in IOU territories. However, DSGS is designed to be available to customers in both IOU and non-

48 The Strategic Reliability Reserve was developed in 2022 as part of Assembly Bill 205 (Committee on Budget, Chapter 61, Statutes of 2022) to expand the resources capable of managing or reducing net-peak demand during extreme events.

IOU territories and continues to expand its participation options to enroll more clean energy resources.

The program was launched in August 2022, with the adoption of program guidelines. On July 26, 2023, the CEC adopted revised program guidelines to bring on more clean resources with expanded participation eligibility, additional incentive options for clean resources, including virtual power plants, and streamlined processes. On May 8, the CEC adopted additional revisions to the guidelines for the 2024 summer season, continuing to streamline participation and incorporating bi-directional electric vehicle chargers as an eligible resource providers can include in the virtual power plant option in DSGS.

- **Distributed Electricity Backup Assets Program** provides incentives for the construction of clean and more efficient distributed energy resources. The CEC adopted program guidelines on October 18, 2023, with program parameters and funding to be made available through grants. The first Distributed Electricity Backup Assets Program grant funding opportunity was released December 7, 2023, for bulk grid efficiency upgrades and capacity additions at existing bulk grid power plants with a funding allocation of $150 million. On April 22, 2024, the CEC released a Notice of Proposed Awards for 9 projects requesting $123 million, which would add ~297 MW of new capacity by 2027 to increase California's grid reliability.

  The CEC released a draft concept proposal for the second grant funding opportunity focused on distributed energy resources on February 23, 2024. The recently adopted budget made modifications to the funding authorization for the DEBA program in terms of funding levels/sources and administrative/regulatory obligations. Considering these modifications, the CEC is working to determine next steps related to the release of the final version of the DEBA Distributed Energy Resources grant funding opportunity.

- **The Electricity Supply Strategic Reliability Reserve Program (ESSRRP)** is being implemented by DWR via the Electricity Supply Reliability Reserve Fund to provide additional generation capacity to support grid reliability. Actions include extending the operating life of existing generation facilities planned for retirement, procuring temporary power generators, procuring energy storage, or reimbursing the above market costs for imports beyond traditional planning standards. At its September 30, 2022, meeting, the Statewide Advisory Committee on Cooling Water Intake Structures recommended that the State Water Board extend the compliance dates for three once-through-cooling plants to support the ESSRRP and allow the power plants to be available for contract to DWR in extreme events. The State Water Board approved the extension of the once-through cooling compliance dates at its August 15, 2023, meeting. As part of the ESSRRP, these once-through cooling plants are only called upon to support grid operations during extreme events and no longer provide power to the market on a consistent basis.

When fully operational, the SRR could provide up to 3,500 MW of additional extreme event support to the state. Both DSGS and ESSRRP were activated to provide resources during summer 2022, and the programs can expend funds until at least June 2031. In addition to the SRR, the state has identified an additional 1,500 MWs of supplemental contingency resources that may be available during an extreme event. In total California has roughly 5,000 MW of contingency resources between the SRR programs and supplemental resources.

California Energy Security Plan Update

The energy sector is uniquely critical to local, state, and national security as all tangential infrastructure sectors depend on energy to operate. For example, the bulk movement of food relies on trucks and trains that require petroleum fuels. Grocery stores that receive the food rely on electricity for lights, refrigeration, and telecom. Consequently, a disruption in critical energy infrastructure can directly affect the security and resilience within and across all critical infrastructure sectors. The 2021 Infrastructure Investment and Jobs Act [49] outlined six elements in Section 40108 that are required to be included in State Energy Security Plans. States are required to submit the appropriate documentation to the United States DOE by September 30, 2024.

The purpose of state Energy Security Planning is to ensure a reliable and resilient supply of energy. This is achieved through efforts to identify, assess, and mitigate risks to energy infrastructure and to plan for, respond to and recover from events that disrupt energy supply. California's energy infrastructure and delivery systems are vulnerable to a broad range of threats and hazards such as, extreme weather, system failures, pandemics, cyberattacks, and deliberate physical attacks. The bulk of California's critical infrastructure such as pipelines, telecom, transmission lines, and power plants are operated and owned by private companies. This creates a relationship in which both the government and private sector are incentivized to reduce disruption risks and frequency. Energy security planning and preparedness coordinates across government agencies and with relevant stakeholders to reduce the risk, vulnerabilities, and consequences of an event and support recovery.

State energy security plans represent an important part of energy security planning. The goals of these updated plans are to describe the state's energy landscape, people, processes, and the state's strategy to build energy resilience. Specifically, the goal of the updated plan is to detail how the state, working with energy partners, can secure their energy infrastructure against physical and cybersecurity threats; mitigate the risk of energy supply disruptions; enhance the response to, and recovery from, energy disruptions; and ensure that the state has secure, reliable, and resilient energy infrastructure.

In September 2022, CEC staff submitted the 2014 California Energy Assurance Plan for review by the United States DOE. The DOE assessment of the 2014 plan identified deficiencies that needed to be addressed in full or in part for the September 2023 submission. Starting in 2023 the United States DOE Office of Cybersecurity, Energy Security, and Emergency Response (CESER) began working closely with the states and other relevant parties to enhance state energy security plans and programs.

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49 H.R.3684 - *Infrastructure Investment and Jobs Act* available at https://www.congress.gov/bill/117th-congress/house-bill/3684.

The CEC staff made substantial updates and reformatted the California Energy Security Plan to align more closely with the guidance and resources provided by the United States DOE CESER team. The updated plan includes six chapters that align with the six elements outlined in the Infrastructure Investment and Jobs Act and thirteen appendices that contain more detailed information on specific subjects such as energy emergency contingency programs and situational awareness tools. In September of 2023, a draft updated Energy Security Plan was submitted to the CESER team for review. In December of 2023, CESER sent a letter to the CEC team noting that the draft California Energy Security Plan met all content requirements. The CESER letter also included recommendations on how the CEC team can further improve the draft plan, specifically to describe resilience efforts. The CEC team is continuing to engage the CESER team as it prepares an update for the targeted September 2024 submission.

CHAPTER 7: Gas System Reliability

2024 Summer Gas Reliability Outlook

This chapter summarizes the CEC's independently prepared Summer 2024 Gas Reliability Assessment (Summer Assessment) of the Southern California Gas Company (SoCalGas) and PG&E gas systems. The southern California seasonal reliability assessments started after the 2015 well leak at the Aliso Canyon underground gas storage field owned and operated by SoCalGas, which severely limited use of that facility. The intent was to inform state energy planners about the reliability of SoCalGas service under normal and hot temperatures and peak demand in the summer, including the reliability of service to natural gas electric generation, which is critical to electric system reliability, particularly in the summer months.[50] For the first time, the CEC includes a high-level assessment of the PG&E system conditions to further assist with energy planning efforts.

Staff prepared the Summer Assessment using mostly publicly available information. The CEC developed a summer gas demand forecast for the analysis of the SoCalGas system in lieu of the gas utilities' *California Gas Report* (CGR) forecast.[51] As part of this Summer Assessment, staff used the CGR for the PG&E system, along with recorded gas demand. Staff plans to develop its own gas demand forecast for the PG&E system to use in future assessments.

SoCalGas Summer Reliability Outlook

This section describes the analytical components and findings of the CEC's assessment of the SoCalGas System, which covers all of southern California including the San Diego Gas & Electric territory. The following is a description of the inputs the CEC developed and/or used in this analysis:

- **Gas Demand Projections:** Staff developed and used demand projections for the SoCalGas system instead of using the utilities' demand projections from the CGR. This includes the forecast of normal and hot temperatures by month and peak day demand.
- **Pipeline Capacity:** Staff compared SoCalGas's projected pipeline capacity to last summer, accounting for projected pipeline maintenance. Based off this examination, staff made assumptions regarding expected availability of the pipeline capacity (see Table 11 below for details).

50 During the summer season, gas demand for electric generation increases while core demand for residential and small commercial decreases. For reference, the gas system defines summer as April 1 to October 31. It is during these months that CEC staff expects to see the utilities inject gas into natural gas storage to prepare for winter as load during winter cannot be met solely with supplies flowing in from the interstate pipelines.

51 The *2022 California Gas Report* can be found at: https://www.socalgas.com/sites/default/files/Joint_Utility_Biennial_Comprehensive_California_Gas_Report_2022.pdf

- **Natural Gas Storage:** Staff reviewed storage levels at Aliso Canyon. A recent CPUC decision increased the maximum storage level allowed at the facility and staff took into consideration how this will affect gas reliability.
- **SoCalGas Summer 2024 Gas Balance:** Staff prepared gas balances for the normal temperature, hot temperature, and peak day demand cases. These cases compare projected available supply to demand and identify conditions where supply will be insufficient to meet projected demand.
- **Hourly Stochastic Analysis:** Staff developed an hourly stochastic analysis of the peak day to observe the hourly changes to demand and assess if storage withdrawals are needed.
- **Hydraulic Modeling:** Staff performed hydraulic modeling to further explore and help confirm the results of the peak day gas balance.

The sections below provide more detailed descriptions of these steps.

Gas Demand Projections

For the reliability assessment, CEC developed three different demand forecasts: 1) normal *temperature gas demand; 2) hot temperature demand; and 3) a peak day case.*[52] Table 10 presents staff's normal temperature and hot temperature forecasts by month in million cubic feet per day (MMcfd).

Table 10: CEC SoCalGas Monthly Demand

	April	May	June	July	August	Sept.	October
(MMcfd)	**2024**	**2024**	**2024**	**2024**	**2024**	**2024**	**2024**
Normal Demand (MMcfd)	2,259	2,056	2,010	2,243	2,343	2,211	2,308
Hot Temperature Demand (MMcfd)	2,258	2,097	2,077	2,332	2,433	2,291	2,285

Source: CEC staff

Staff was particularly mindful of the use of gas-fired generation during the September 2022 heat storm. The 2022 CGR's summer peak day demand forecast for SoCalGas, however, was significantly lower than the actual peak demand observed during that heatwave — about 800 MMcfd lower.[53] This difference is attributed to the high electricity loads during that period,

52 Note that these scenarios were developed using different data and a different methodology than that used for the IEPR gas forecast, which looks at annual gas demand out to 2040. It was necessary to use different data in order to forecast daily gas demand.

53 SoCalGas served all customers during the September 2022 heat storm without any curtailments. However, a Southern System Curtailment Watch was in effect during this time.

which translated to much higher use of natural gas to generate electricity.[54] In preparing the 2024 summer peak day natural gas forecast for this analysis, staff set its peak electric generation gas demand at the level between that observed in the summer 2022 heat event and SoCalGas's highest observed summer electric generation (EG) demand of 1,870 MMcfd in 2015.[55] Table 11 presents the peak day demand forecast for core (residential and small commercial) and noncore (typically electric generation, industrial, large commercial but this table also includes a noncore minus electric generation scenario). The methodology for all three forecasts appears in Appendix A.

Table 11: CEC SoCalGas Summer Peak Day Demand

Demand Type	Summer Peak Day (MMcfd)
Core	527
Noncore- Non-Electric Generation	785
Noncore- Electric Generation	1,810
Total Demand	**3,122**

Source: CEC staff

Pipeline Capacity

Staff made assumptions regarding expected availability of the pipeline capacity on the SoCalGas system. SoCalGas' pipeline capacity improved in 2023 after repairs allowed the northern zone (Lines 235, Lines 3000, and Lines 4000) to reach its design capacity of 1,590 MMcfd, despite Line 3000[56] continuing to operate at reduced pressure. However, ongoing maintenance continues to hamper deliverability and has reduced capacity from this nominal amount for summer 2024.[57] Multiple weeks of unplanned maintenance occurred in the winter 2023/2024 on Line 4000 due to safety/reliability issues and multiple weeks of planned maintenance are scheduled during summer 2024 on Line 235 East for remediation and Line

54 In the 2022 CGR, the summer demand forecast was updated and declined due to the assumptions used, including those relating to renewable resources and the electric demand forecast. For the California ISO system, these assumptions reflected the latest version of the CEC IEPR demand forecast and CPUC's Integrated Resource Planning PSP available at the time of the preparation of the report. The assumptions that supported the 2022 CGR's summer demand forecast relied on data from the CEC and do not seem to have considered this kind of extreme region-wide heat event experienced in summer 2022. Assumptions associated with renewable and energy storage adoption, as well as availability of imported power, may also have contributed to differences between the forecast and actuals.

55 SoCalGas, in both its 2023 and 2024 summer assessments, used a "hybrid" in place of the 2022 CGR forecast for these same reasons.

56 SoCalGas Line 3000 has been operating at reduced pressure for several years, which reduces receipt point capacity by 190 MMcfd at the Topock receipt point per SoCalGas Envoy®.

57 The planned maintenance events captured in the analysis were posted on SoCalGas' Envoy®, SoCalGas' electronic bulletin board, as of April 2, 2024.

4000 for hydrotesting. More inline inspections are scheduled on Line 235 later this summer 2024 and also on Line 2001 in the Southern zone in June 2024. The inline inspections may remove the line from service for several days, but the results of the inspections may require repairs that remove a line from service for multiple weeks. Table 12 provides a detailed look at the pipeline capacity assumptions. [58, 59]

Table 12: SoCalGas Pipeline Capacity Assumptions

Supply (MMcfd)	2024 Apr	2024 May	2024 Jun	2024 Jul	2024 Aug	2024 Sep	2024 Oct
California Line 85 Zone	70	70	70	70	70	70	70
Wheeler Ridge Zone	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone	710	980	910	980	980	980	980
Otay Mesa into Southern Zone	0	0	0	0	0	0	0
Kramer Junction into Northern Zone	550	550	550	550	550	550	550
North Needles into Northern Zone	455	350	350	430	455	460	425
Topock into Northern Zone							
Total Supply	2,550	2,715	2,645	2,795	2,820	2,825	2,790

Source: CEC staff

SoCalGas' Northern and Southern Zones represent portions of its system connected to different interstate pipelines. SoCalGas' Southern Zone receives gas primarily from the Permian basin in Texas via El Paso Natural Gas. SoCalGas' Northern Zone is connected to southwestern U.S. Southwest (Transwestern, El Paso, Kern River, and Mojave) at Needles, west of Topock Arizona, and connects to Kern River Gas Transmission to receive Rockies gas at Kramer Junction in San Bernardino County and at Wheeler Ridge, south of Bakersfield.[60] The following list provides a summary of the capacity assumptions by major zone from Table 12:

- The Northern Zone capacity ranges between 980 MMcfd and 1,010 MMcfd during the summer months of July through September, depending on maintenance that SoCalGas has announced it will conduct. This is still below the nominal capacity of 1,590 MMcfd.
- Wheeler Ridge capacity is 765 MMcfd.

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58 Staff relied on SoCalGas' Envoy® as the primary data source for the Summer Assessment capacity assumptions. Envoy reports the capacity available to its customers for scheduling and maintenance and outage events that impact the capacity.

59 Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southwest Gas Corporation, City of Long Beach Energy Resources Department, and Southern California Edison Company, 2022. 2022 California Gas Report, California Gas Report | SoCalGas. The CEC also reviewed the 2022 California Gas Report, which describes SoCalGas' receipt point and transmission zone firm capacities.

60 Ibid.

- California production delivered to SoCalGas is assumed to be 70 MMcfd.
- The Southern Zone capacity is 980 MMcfd during the summer months of July through September. An inline inspection on Line 2001 is scheduled in June, reducing capacity to 910 MMcfd in early summer.

The sum of the capacities above ranges between 2,795 MMcfd and 2,825 MMcfd during the summer months. The El Paso pipeline near Phoenix, which ruptured in August 2021, returned to service on February 15, 2023, after an 18-month outage. This key pipeline's return to service removed the upstream impact on El Paso's southern mainline, allowing full flows to SoCalGas' Southern Zone.[61]

Natural Gas Storage

Since the 2015-16 well leak at Aliso Canyon, the CPUC established natural gas storage inventory limits at Aliso Canyon. This was initially set at 15 billion cubic feet (Bcf) in 2016, increasing to 34 Bcf in 2020, based on a level needed to meet reliability. Subsequently, the CPUC increased the limit to 41.16 Bcf to help protect ratepayers from reliability issues and rate impacts during the 2021 winter season. On August 31, 2023, CPUC Decision 23-08-050 increased the limit to 68.6 Bcf in a further effort to help protect ratepayers from potential rate impacts. This decision and the elimination of the Aliso Canyon Withdrawal Protocol[62] essentially remove all operating restrictions at Aliso Canyon.

After the CPUC voted to increase inventory at Aliso Canyon, SoCalGas began injecting into Aliso Canyon to reach this limit to prepare for winter 2023/2024. Aliso Canyon reached the maximum reservoir pressure authorized by California Department of Conservation's Geologic Energy Management Division (CalGEM)[63] before it reached the 68.6 Bcf. In January 2024, SoCalGas requested that CalGEM evaluate a higher maximum reservoir pressure for the facility. CalGEM has not announced a decision on this request.

SoCalGas total allowable storage inventory across all of its four fields is about 109 Bcf with Aliso Canyon at about 59 Bcf. Due to warm temperatures this past winter 2023/2024, SoCalGas ended the winter gas season (March 31, 2024) with 95 Bcf in inventory, which is about the same amount as when the season started (November 1, 2023).[64]

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61 The Southern zone is comprised of Blythe/Ehrenberg and Otay Mesa in Table 11.

62 The Aliso Canyon Withdrawal Protocol describes the conditions allowing SoCalGas to make withdrawals from the field and was put in place after the well leak at Aliso Canyon to preserve inventory to meet reliability.

63 *Enclosure 1* identifies the maximum reservoir pressure at Aliso Canyon: https://www.conservation.ca.gov/calgem/Documents/Aliso/Enclosure1_2017.7.19_Updated%20Comprehensive%20Safety%20Review%20Findings.pdf. CalGEM translated the maximum reservoir pressure to 68.6 Bcf inventory, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/alisofaq_2021-01-26.pdf.

64 The natural gas industry across the country treats November 1 as its winter withdrawal start and March 31 its end.

SoCalGas Summer 2024 Gas Balance

Staff analyzed monthly normal temperature, monthly hot temperature, and summer peak day demand (Tables 13-15) to assess availability of supply to meet demand under these cases.[65] Table 13 and Table 14 show the monthly gas balance for the months of April-October 2024 using the CEC's forecast (row 1) for normal demand and for hot temperature demand. Both tables capture pipeline and storage field planned maintenance as of April 2, 2024, and is reflected in row 2 Available Pipeline Capacity. Staff's analysis shows that pipeline capacity (row 2) is sufficient to meet demand and refill storage, thereby allowing SoCalGas to undertake planned maintenance during the summer months without jeopardizing reliability. Since the hot temperature case has only a modest increase in demand above the average demand, the cases demonstrate an identical storage injection pattern (row 3). In both cases, storage is full by May 2024, showing that there is flexibility to inject later in the summer season.

Table 13: SoCalGas Monthly Gas Balance Normal Demand Case

Row	Normal Demand	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October
1	Demand (MMcfd)	2,259	2,056	2,010	2,243	2,343	2,211	2,308
2	Available Pipeline Capacity (MMcfd)	2,550	2,715	2,645	2,795	2,820	2,825	2,790
3	Injection/(Withdrawal) (MMcfd)	165	290	0	0	0	0	0
4	End-of-Month Inventory (Bcf)	100	109	109	109	109	109	109

Source: CEC staff

Table 14: SoCalGas Monthly Gas Balance Hot Temperature Demand Case

Normal Demand	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October
Demand (MMcfd)	2,258	2,097	2,077	2,332	2,433	2,291	2,285
Available Pipeline Capacity (MMcfd)	2,550	2,715	2,645	2,795	2,820	2,825	2,790
Injection/(Withdrawal) (MMcfd)	165	290	0	0	0	0	0
End-of-Month Inventory (Bcf)	100	109	109	109	109	109	109

Source: CEC staff

65 In prior years, CEC staff used the demand projections from the California Gas Report. Appendix A describes the method used to develop the CEC demand projections.

Though the SoCalGas system is winter peaking and designed to meet winter demand with flowing pipeline supply and storage withdrawals, SoCalGas also needs withdrawals to meet demand on a peak summer day. SoCalGas needs sufficient inventory to meet the required withdrawals. SoCalGas Envoy® now reports storage inventory by field and total inventory for each day. Current inventory levels provide sufficient inventory to allow withdrawal during the hotter summer months and on a peak day if one occurs. Currently, SoCalGas storage inventory is the highest it has been at the start of summer at 102 Bcf as of May 28, 2024, since 2015 and puts SoCalGas in a good position for having storage full by next winter even if it needs to withdraw gas during the summer.

Peak Day Analysis

Staff evaluated a summer peak day demand scenario with electric generation comprising the bulk of the demand. Table 15 presents the results of this analysis for the summer peak day. As is also the case in staff's normal condition gas balances, the available pipeline capacity varies slightly by only 30 MMcfd during the summer months of July, August, and September based on planned maintenance. SoCalGas is planning maintenance throughout the summer, which leaves pipeline capacity about 2.8 Bcf during the summer months. For simplicity, staff uses the lowest pipeline capacity during these months for this peak day analysis since the capacity varies only by 30 MMcfd during these months. The results of the peak day analysis show that 327 MMcfd of storage withdrawal is needed to meet the peak day demand. The monthly gas balance cases in the tables above show that SoCalGas' storage inventories reached 109 Bcf by May 2024.[66] This is more than sufficient to allow the needed storage withdrawals of 327 MMcfd projected in Table 15.[67] Based on the assumed conditions, staff finds that supply can meet peak demand, resulting in minimal risk of curtailment to the electric generators. Absent a multi-day hot weather event combined with additional infrastructure outages, the risk to reliability is low.

Table 15: SoCalGas Peak Demand Day Gas Balances (2024)

MMcfd	Summer
Demand	
Core	527
Noncore-NonEG	785
EG	1,810
TOTAL Demand	3,122
Less Available Pipeline Capacity	-2,795
Needed Withdrawal	327

Source: CEC Staff

66 The actual storage inventory at the end of May 2024 was 102 Bcf, below the projection of 109 Bcf.

67 SoCalGas' storage inventory of 95.2 Bcf is sufficient to meet the needed storage withdrawal of 327 MMcfd.

Stochastic Analysis

Staff prepared an hourly gas balance using a stochastic forecast for a demand in each hour of a summer peak day. This forecast uses the same modeling methodology used in staff's 2022 winter assessment.[68] This analysis allows for demand to vary randomly within the range observed over 12 years of recorded hourly and daily demand data. This captures a greater range of variation in gas demand, especially hourly demand patterns that are not reflected in the standard peak day demand analysis shown in Table 15. The hourly demand data focused on a subset of summer days reaching over 80 degrees composite temperature[69] in the SoCalGas territory, capturing variability coinciding with the peak EG gas demand during the summer, and using the CEC's summer peak day demand for aggregate daily demand. This yields a stochastic load shape for a summer peak day, summing to the total forecast summer peak day demand of 3,122 MMcfd used in Table 15. The stochastically determined load shape then feeds into the hourly gas balance, which uses the same assumptions as the peak day analysis for pipeline capacity (2,795 MMcfd). This comparison of supply and demand during each hour of the day yields the required withdrawals for each hour of the simulated day.

Table 16 gives the hourly gas balance results for a single load shape scenario. It highlights the key ramping period in the middle of the day, the afternoon hourly peak demand, and the required withdrawals needed in certain hours. The stochastic assessment confirms the adequacy of supply to meet demand and no risk of potential curtailments under summer peak day conditions.[70]

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68 California Energy Commission, *Winter 2022-2023 Southern California Gas Company Reliability Assessment*, available at: https://www.energy.ca.gov/publications/2022/winter-2022-2023-southern-california-gas-company-reliability-assessment.

69 Composite temperature is a weighted average temperature. The calculation first takes the daily temperature of several locations in the territory, then averages those into one number. This can be found on SoCalGas' Envoy® website.

70 The analysis estimates zero curtailment provided SoCalGas is able to withdraw from storage to meet demand during the peak hours. The maximum hourly withdrawal estimated during the summer peak day is 54MMcf, and a total of 447MMcf over the entire gas day.

Table 16: Stochastic Hourly Gas Balance Results for the Summer Peak Day (Mmcf)

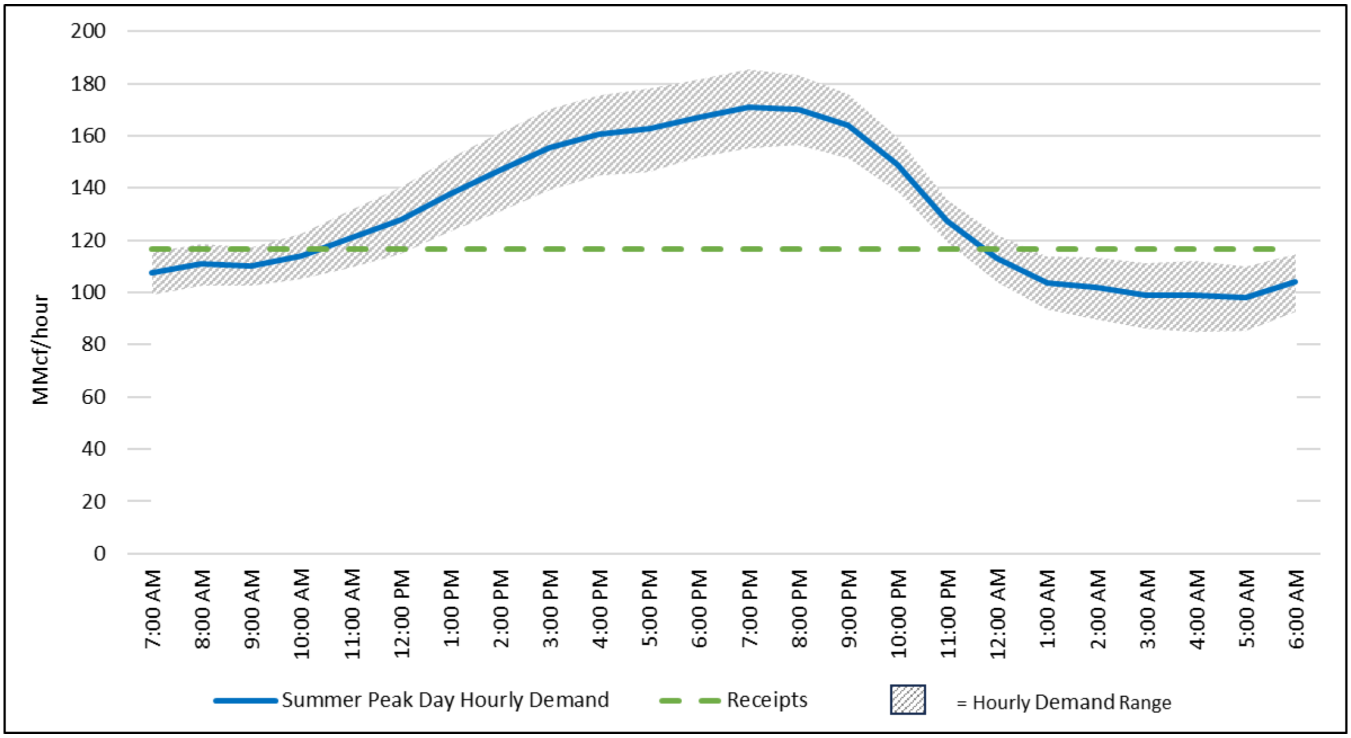
Hour	Demand	Receipts	Required Withdrawals	Curtailment
7	107	116	0	0
8	111	116	0	0
9	110	116	0	0
10	114	116	0	0
11	121	116	4	0
12	128	116	11	0
13	138	116	21	0
14	147	116	30	0
15	155	116	39	0
16	161	116	44	0
17	163	116	46	0
18	167	116	51	0
19	171	116	54	0
20	170	116	54	0
21	164	116	47	0
22	149	116	33	0
23	127	116	11	0
0	113	116	0	0
1	104	116	0	0
2	102	116	0	0
3	99	116	0	0
4	99	116	0	0
5	98	116	0	0
6	104	116	0	0
Total	3122	2795	447	0

Minimum Curtailment Required in Each Hour

Source: Aspen Environmental Group

Figure 19 gives a broader display. The shaded range shows the range of potential demand for each hour. A dotted line shows fixed hourly receipts, consistent with pipeline operations and tariff requirements that call for flat hourly flows. A solid line represents the summer peak day load shape scenario included in the hourly gas balance in Table 16. The hours where demand is above the receipts dotted line indicate storage withdrawals would be needed to meet that day's demand. Seeing the range of demand also allows one to imagine the range of potential withdrawals on that peak day.

Figure 19: Summer Peak Day Demand by Hour



Source: Aspen Environmental Group

PG&E Summer 2024 Reliability Outlook

For the first time, staff assessed the summer reliability outlook of the PG&E system. This reliability outlook includes a lookback at a recent peak event that occurred in summer 2022.

PG&E remains a winter-peaking gas utility, with December demand in an average winter showing demand of 2,722 MMcf per day[71]. Under colder conditions expected to occur once in ten years, PG&E projected total demand of 3,984 for winter 2024-2025. To reflect the 1-in-90 planning criterion for core customers, staff typically takes the 3,070 PG&E projects for core and adds the 1-in-10 condition noncore demand. This yields 4,474 MMcfd to fully serve the load of all customer classes on a very cold day. This approach allows the CEC to estimate explicitly how much load might need to be curtailed on those days.[72]

For summer 2024, PG&E projects peak day demand of 1,860 MMcfd (CGR, p. 100). Nearly half of this, 927 MMcfd, is from gas-fired electric generation. Relative to pipeline capacity of 2,888 MMcfd,[73] PG&E would appear to be able to serve all summer peak day demand and pose no

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71 PG&E's 2023 IEPR Natural Gas Demand Form CEC TN251011.

72 *2022 California Gas Report*, page 99. https://www.socalgas.com/sites/default/files/Joint_Utility_Biennial_Comprehensive_California_Gas_Report_2022.pdf.

73 This figure includes a small amount of gas produced in northern California.

issues with summer reliability. The 1,860 MMcfd demand excludes off-system deliveries but under this forecast, PG&E has sufficient pipeline capacity to easily make those deliveries.

Staff reviewed PG&E's most recent summer gas system peak event for comparison. The most recent peak occurred during the September 2022 heat storm, when customers on PG&E's system experienced a composite system temperature of 88 degrees on September 6. PG&E's total gas system load that day was 3,054 MMcf. (This includes deliveries to the SoCalGas system of 400 MMcf that were excluded from the peak day forecast.) Electric generation accounted for 1,430 MMcf of system load that day.[74] As with the forecast, this represents roughly half of total system demand. This 2022 extreme event created electric generation demand nearly 400 MMcfd higher than the forecast peak day load for 2024. It was a dry year in 2022.[75] Electric generation demand typically is higher during dry years because there is less hydroelectric output available.

PG&E's total backbone pipeline capacity consists of its Redwood Path (Lines 400 and 401) plus the Baja Path (Lines 300A and B). PG&E also receives a small amount of gas produced natively, in northern California. The CGR assumes 3,051 MMcfd of "flowing supply" available from these sources (p. 98), before counting any gas from underground storage. Calculations using PG&E figures from its General Rate Case suggest a slightly lower available capacity of 2,880 MMcfd. Either figure is higher than the peak experienced September 2022 or the projected summer peak for 2024 from the 2022 CGR.

Notably, on the September 2022 peak day, total demand was 3,186 MMcfd, yet PG&E's pipelines received only 2,429 MMcfd at the border points plus 26 MMcfd from local production. To provide the remaining gas needed to meet demand that day, PG&E had to make withdrawals from underground gas storage (mostly from independent storage). While PG&E shippers apparently chose to use gas from underground storage on this peak day, had they not done so, there was approximately 135 MMcfd of demand that would have required underground storage withdrawals or face curtailment were those not feasible.[76] The end result is that storage was required to serve all demand on this peak day.

This September 2022 peak day highlights the value of summer flexibility to withdraw gas from underground storage should such high demand from extreme conditions occur in future years. The dry conditions experienced in 2022 do not appear to be likely for summer 2024. Staff concludes PG&E summer reliability to be adequate and absent a multi-day hot weather event with infrastructure outages, the risk to reliability is low.

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74 Note that the recorded class demands reported on Pipe Ranger that we are reporting here are not the values collected from customer meters and are delineated "After-Day Cast." They are not exact or final; they are, however, published and publicly available.

75 The day after, with a somewhat lower system composite temperature, gas load was slightly higher: 2,654 MMcf plus the 400 MMcf delivered to SoCal.

76 Assuming full pipeline supplies of 3,051 and demand of 3,186 MMcfd, storage withdrawal of 135 MMcfd would be required to meet demand.

Hydraulic Analysis

For this assessment, CEC staff performed hydraulic modeling assessments of California's natural gas pipeline systems. Hydraulic models apply nonlinear equations that capture fluid flow dynamics for a compressible liquid to simulate the complex interactions between gas supply entering a system, gas supply leaving the system as it is consumed by end users, and the detailed physical configuration of the system. Through the use of transient modeling, the hydraulic model simulates operations across the entire gas day, capturing changes in line pack that the peak day gas balance cannot. Gas utilities routinely use hydraulic assessments to simulate system operations and evaluate the ability to serve load under various demand, supply, and capacity conditions. The CEC independently conducts hydraulic assessments to confirm results obtained from the gas utilities and crafts and runs scenarios and cases for consideration by policy makers.[77] Staff performed hydraulic modeling analysis on the transmission systems of both PG&E and SoCalGas.

SoCalGas

For the hydraulic modeling analysis of the SoCalGas system, staff incorporated the summer peak day demand case as well as the load profiles prepared by utility and submitted to the CEC in 2024. Staff used the pipeline supply of 2,795 MMcfd assumed in the gas balances ratably, meaning the same quantity every hour.[78] Storage injections and withdrawals, in contrast, vary hourly to meet the difference between demand and supply flowing in from the interstate pipelines. Staff found that storage injections would occur on some hours of the peak day, but that overall withdrawals exceeded injections on the summer peak day. Storage withdrawals were needed in peak hours to maintain system pressures and limit the use of linepack (storing gas in the pipeline as opposed to within a storage facility). The hydraulic analysis confirms staff's gas balance results.

Load profiles for electric generation can significantly impact hydraulic modeling results. The load profiles in the hydraulic model assume how gas demand would be distributed for individual or groups of customers throughout the gas day. Load profiles with higher peaks can result in higher storage withdrawal totals during higher demand hours and higher storage injection totals in lower demand hours. In comparison, incorporating load profiles showing more constant gas demand throughout the day can lead to more consistent injection or withdrawal totals. This has real world implications for the summer operation of the gas system. As California's electricity system relies on more solar generation during the morning and afternoon hours, EG gas demand is lower in those hours. Storage injections during those

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77 The CEC uses DNV-GL's Synergi Gas® hydraulic modeling platform for its analysis, including this assessment. Most large gas utilities in the U.S., including PG&E and SoCalGas, use this software. CEC data regulations (Title 20, Division 2, Chapter 3, Article 1 Section 1314 of the California Code of Regulations) require the utilities to provide to the CEC with copies of their hydraulic models. In addition, gas utilities also provide the CEC with information on system minimum and maximum allowable pressures, demand scenarios, and load profiles. Staff bases hydraulic modeling analysis on these submittals.

78 This is the commonly accepted operating practice for gas pipelines and distribution systems and is embodied in company tariffs across the industry.

times may increase, while storage withdrawals may spike more in the evening hours as EG demand increases when the sun goes down. The hours in which demand is low may require more injections to keep system pressures from getting too high.

Staff's analysis of the SoCalGas hydraulic model confirms that if expected summer pipeline conditions hold in combination with small amounts of storage withdrawals, the SoCalGas system should be able to meet summer peak day demand.

PG&E

Staff performed an analysis of the PG&E hydraulic model. PG&E's backbone system hydraulic models are run on a steady state basis as the PG&E gas system can withstand variation in line pack as much as 400 MMcfd within a gas day (whereas SoCalGas cannot). For its analysis, staff used the estimated 1,860 MMcfd summer peak day demand. In its analysis, staff found that the peak day demand could be met, in addition to storage injections and off system deliveries.

Conclusion

Supplies into the state have improved over the last year. El Paso returned to full service in February 2023 its southern mainline that brings gas to Ehrenberg, which increased supplies on SoCalGas Southern system. SoCalGas continued repairs on its Northern system returning capacity to its design capacity of 1,590 MMcfd in 2023, despite Line 3000 operating at reduced pressure. However, ongoing maintenance continues to hamper deliverability, reducing capacity from this nominal amount. Storage is projected to be sufficient to meet peak summer demand. The high ending inventory from winter 2023/2024 provides flexibility for replenishing storage in time for winter. Staff projects zero curtailment on a summer peak day demand. Staff has confirmed this finding using peak day gas balances, a stochastic hourly gas balance and hydraulic simulations of gas system operations. Absent a multi-day, hot weather event with additional infrastructure outages, the risk to reliability is low.

CHAPTER 8: Conclusion

California continues to be a leader on policies that shift energy resources away from fossil fuels, and the state is committed to rapidly building new clean energy resources. At the same time, California is experiencing more frequent and prolonged extreme weather events because of climate change that strains the state's energy systems. The CEC will continue to develop and expand future annual iterations of the California Energy Resource and Reliability Outlook to provide comprehensive, statewide assessments of energy resource planning and reliability. This may include, but is not limited to, incorporating more accurate and frequent data sets, continuing to collaborate with the POUs on reliability topics, and expanding the scope of content contained in the report.

Summer 2024 Outlook Key Takeaways

- Summer climate forecasting predicts higher than average temperatures west wide this year.
- This summer's significant fire potential, in California, is near- to below-normal during June and July, then becomes normal during August and September due to seasonal curing and increased lightning strike potential.
- Fire risk to critical transmission lines such as the California-Oregon Intertie continue to be a concern, as this critical intertie crosses through an "Above Normal" Fire Potential zone[79] in the southeast corner of Oregon.
- In combination with significant reservoir levels, hydroelectric generation is anticipated to be at least at average levels.
- The summer outlook is optimistic based on LOLE modeling and stack analysis.
- A combination of unforeseen events, coincident fire risk, extreme events, and/or resource build-out delays may create challenges during the summer. Delays in storage build-out impact reliability the most.
- Continued growth in the SRR provides nearly 3,500 MW that the state can draw on to support reliability.
- An additional 1,500 MWs of contingency resources may also be available during extreme events.
- The risk to gas service reliability is low, absent a multi-day heat event with additional infrastructure outages.
- Given the projected conditions in the electric and gas systems, weather, and fire outlook, the summer 2024 outlook is cautiously optimistic.

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79 National Significant Wildland Fire Potential. Available at: https://www.nifc.gov/nicc/predictive-services/outlooks

APPENDIX A:
AB 209 POU PRM Recommendations

Recommendations

AB 209 (Committee on Budget, Chapter 251, Statutes of 2022) requires the CEC develop recommendations about approaches to determine an appropriate minimum PRM for local POUs within the California ISO balancing area. The goal is to develop recommendations that promote consistency across the California ISO while also considering utility-specific characteristics. The following provides recommendations for implementation by the POUs to set PRMs.

The recommended approach for PRM setting is a Monte Carlo (stochastic) simulation with the effective load carrying capacity (ELCC)/NQC accounting. This approach models a system calibrated to a target LOLE, then uses existing resource accounting to estimate the PRM. This approach could be conducted on either the whole California ISO system or an individual utility. However, modeling small systems reliant on only a few generators may require very high PRMs to meet reliability targets.

The steps are as follows:

1. Evaluate the reliability of the system, including planned additions, by analyzing the operations under various weather years and combinations of unplanned outages at generating facilities.
2. Calibrate the resource mix to 0.1 LOLE, defined as one day of outage for every ten years sampled. This can be done by either adding/removing load or scaling the supply; either approach should give similar results. If large adjustments are required care should be taken in selecting the approach, and alternatives should be explored.
3. Add up the NQC values for the resource mix appropriately scaled to the 0.1 target.
4. Divide the total NQC required by the forecasted peak, and subtract 1, to get the PRM.
5. Apply utility-specific considerations, such as reductions to account for controllable loads.

If the updated PRM is significantly greater than a POU's current planning standard, it may be necessary to incrementally increase the PRM over time to avoid significant impacts to ratepayers. The CEC acknowledges that the near-term RA market is expected to be tight and short-term contracts to achieve a higher PRM may either not be available or result in costs beyond what has been historically acceptable. However, it is good utility practice to plan for long-term needs and consider the risks of the market. As such, POUs should be planning to meet reliability standards and develop strategies to ensure resources are available to meet their RA needs.

Future Updates

In 2023, the California ISO kicked off its RA Modeling and Program Design Initiative, which is exploring RA rules, requirements, and processes to ensure the future reliability and operability of the grid. Track 1 of this initiative includes updating the California ISO's default PRM and evaluating the extent to which counting rules should reflect resource outages and performance. The CEC is supportive and engaged in the California ISO's RA initiative and will work with the ISO on alignment of future AB 209 recommendations and modeling to identify a specific PRM to maximize consistency. POUs should update their PRMs if the California ISO's default PRM, adjusted for any utility-specific considerations, is above their current Local Regulatory Authority adopted PRM. If necessary, POUs may consider incrementally increasing their PRM over time if market conditions restrict the availability of acceptably priced short-term resource adequacy products. CEC may revisit and revise these recommendations based on the conclusion of CAISO's RA Modeling and Program Design Initiative.

APPENDIX B: Western Coordination Update

Overview

The CEC, CPUC, California ISO and utilities invest significant resources to undertake coordination with many other entities in the Western United States. This investment is essential because California is not an electrical island; its complex electrical system is an integral part of the Western Interconnection (WI) — a synchronous machine that allows 11 western states and two Canadian provinces to operate their generation and transmission at the same frequency. While this may seem straightforward, it is not; the WI is an immense region with great diversity in geography, political boundaries, weather, generation characteristics, loads, and time zones. Mandatory reliability standards put into place by Congress in 2005 have proven necessary to ensure consistent regulation, compliance, and interconnection reliability.

In its *2022 IEPR Update,* the CEC highlighted the importance of increasing integration of the western electricity systems through implementation of more regional approaches to markets, RA and transmission investment. In the two years elapsed, the California energy agencies, key Western states and utilities, and the California ISO have made major progress in developing existing and new integration initiatives. The following subsections provide a status update by highlighting action in four key western integration topic areas: markets, transmission, regional governance and reliability risk assessment.

Markets: Enhancing Economics and Reliability

Significant variations exist in the degree of organization of wholesale markets in the US. While the majority of major load centers are served by Regional Transmission Operators (RTOs), some regions are decentralized in operations and governance of major functions. The WI is one region that has been unable to reach agreement on forming a regional transmission organization in spite of many efforts in past decades to do this at the sub-regional level. At least 38 balancing authorities function in the Western states and two Canadian provinces, dispatching their systems independently from one another. A central goal of regional integration is to bring these autonomous entities into more efficient coordinated methods of system dispatch; wholesale markets are one essential mechanism to do this, including options for real-time, day-ahead and regional full function markets. Most recent Western progress is described below.

Real-Time Markets--Continued Impressive Performance

The energy imbalance market of greatest interest to California is the Western Energy Imbalance Market (WEIM). The WEIM, established in 2014, is a real time wholesale energy trading platform that allows participants from anywhere in the West to buy and sell power. Using advanced market tools, the market ensures that the lowest-cost generation among all the participants is dispatched to meet load, greatly increasing efficiency. This market has attracted voluntary participation of 22 active balancing authorities from 11 states and British Columbia. Administered by the California ISO, the WEIM is governed by an independent body of five non-affiliated directors, nominated by a diverse set of stakeholder sectors.

One result of the large footprint of WEIM is that it has yielded far higher than originally anticipated benefit to entities and their ratepayers. WEIM economic benefits reported for the first quarter (January–March) of 2024 were $436 million[80] and the cumulative total since its 2014 inception is $5.5 billion. Of equal importance to direct ratepayer benefits, WEIM has enhanced reliability in both normal and stressed system operation. In September 2022, for example, the WEIM enhanced balancing area communication and support, providing an important role in the efforts to maintain electric reliability during a long, intense heatwave. In summer of 2023, WEIM added a new feature called the Assistance Energy Transfer mechanism, a voluntary tool allowing balancing authorities to arrange for additional WEIM energy transfers under very tight supply conditions. In August 2023, five balancing areas from across the WI utilized the program to maintain system balance during periods of very high loads.

A second real time market functions primarily on the eastern side of the WI, administered by the Southern Power Pool (SPP). This market, the Western Energy Imbalance Service, is also highly effective, with accrued net benefits approaching $100 million since its inception in early 2021. Its major participants are in Colorado and Wyoming and include investor-owned Excel Energy, public utilities/cooperatives, along with two regions of the Western Area Power Administration, a federal entity responsible for generating, selling and delivering power to mostly rural community customers.

Day-Ahead Markets-- Progress and Evaluation of Benefits

With support from nearly all stakeholder sectors across the WI, major steps forward have been taken during 2023-2024 to harness even greater benefits through increased coordination of system dispatch to harness diversity, moving beyond real-time to day-ahead. Of greatest interest to California is the Enhanced Day-Ahead Market (EDAM), while the SPP has engaged many stakeholders in developing its version of day ahead: Markets+. Development status and benefit evaluation progress are described below.

EDAM Achieves FERC Tariff Approvals

At the time of publishing the *IEPR 2022 Update*, the California ISO was in its final stage of developing EDAM. Through 2023 major strides forward were made. Key milestones included: unanimous joint approval of market design by both the WEIM Governing Board and the California ISO Board of Governors, with support from most stakeholders and the Body of State Regulators; filing of the proposed tariff with FERC in August; holding a public forum in Las

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80 California ISO "*Western Energy Imbalance Market Benefits Report: First Quarter 2024*", April 30, 2024. Available at https://www.westerneim.com/Documents/iso-western-energy-imbalance-market-benefits-report-q1-2024.pdf

Vegas at which time PacifiCorp and BANC announced intention to join the market; most importantly, a FERC Order granting nearly full tariff approval was released in late December, 2023.

Progress has continued in 2024. Additional endorsements and statements of intent to join the EDAM have come from: LADWP, Idaho Power and Portland General Electric. The California ISO, on April 12, 2024, refiled with FERC on the EDAM Transmission Revenue Recovery design which was rejected without prejudice in the December order. On March 7, 2024, FERC approved tariff revisions to enable the California ISO BA to participate in EDAM. Stakeholder working group consideration of GHG tracking/valuation continues and go-live is anticipated January 2026.

Markets+ Makes Tariff Filing

Major progress has also occurred in development of the SPP day-ahead market. Stakeholders in working groups have voted on many dimensions of the market design and developed a draft tariff posted for comment. While myriad issues have been deferred for future resolution, the tariff was ultimately approved by the Participants Executive Committee, State Committee, the Interim Markets+ Independent Panel (IMIP) and the SPP Board of Directors. SPP filed the Markets+ tariff with FERC on March 31, 2024. Phase 1 participant agreements included market development costs incurred during the FERC tariff review; however, one participant, the Western Area Power Administration Desert Southwest region, has elected to withdraw its participation. Phase 2 of Markets+, which requires some financial commitment from prospective participants, is contingent upon FERC approval of the filed tariff and has been delayed until 2025. The tentative schedule from SPP reflects participants desires for Markets+ to begin operations in the second quarter of 2027.

Participants Estimate Potential Benefits of Joining Different Day-Ahead Footprints

Key studies of benefits/costs of organized markets have been undertaken in the past decade. A state led study prepared by Energy Strategies was completed in 2016 and an E3 study was sponsored (but never released by) by 26 utility entities in 2021. Other detailed evaluations of specified market designs for individual participant entities have been performed by Brattle, et al. and were completed in August 2023 and March 2024. These more focused, recent and relevant evaluations described below were funded by individual balancing areas positioning to choose a day-ahead approach. As a caution, benefit estimation for specific day-ahead market designs are fraught with difficulty as in large measure they are dependent on the presumption of participation. Larger and more diverse (in multiple dimensions) footprints, magnitude of load served, and total kWh transactions drive the analytic results. Other key parameters such as the modeling technique (zonal v. nodal) the timeframe and the types of services/benefits quantified will determine magnitude of results. Examples of four major day-ahead market assessment exercises are highlighted below. While methods and results differ, they consistently demonstrate high value for initiatives to further integration through market implementation.

Western Transmission Coordination

Major New Transmission Projects Are Adding Capacity

Despite the long running challenges with regional coordination and interconnection-wide transmission planning, some new regional transmission is getting built. Many of these projects feature designs to enable flows of wind power across the WI from wind resources in the east to load centers in the west. Further, a significant proportion of these projects are being developed under merchant transmission paradigms. Notably, none of the projects are the result of any regional or inter-regional planning process designed to evaluate transmission solution alternatives from a broad WI perspective.

Important regional projects making progress include:

- Ten West Link, California and Arizona – merchant 500 kV line (2024)
- Gateway West, Wyoming to Idaho – 500 kV and 230 kV lines developed by PacifiCorp (2024)
- Gateway South, Wyoming to Utah – 500 kV line developed by PacifiCorp (2024)
- SunZia, New Mexico and Arizona – merchant HVDC line proposing to utilize the novel California ISO subscriber participating transmission owner model (2026)
- Boardman to Hemingway, Idaho and Oregon – 500 kV line in joint development by Idaho Power and PacifiCorp (2026)
- Greenlink North and Greenlink West, Nevada – 525 kV lines developed by NV Energy (2026)
- SWIP - SWIP-North, Idaho to Nevada – merchant 500 kV line; estimated 2027 completion
- TransWest Express, Wyoming to Nevada – merchant 500 kV and 320 kV lines proposing to utilize the novel California ISO subscriber participating transmission owner model (2027).

Increased Western States Engagement

A notable success resulting from the Committee on Regional Electric Power Cooperation (CREPC) 2023 sponsorship of the Western States Transmission Initiative (WSTI) was the formation of the CREPC TC. CREPC TC is an informal working group designed to focus on regional transmission issues. The CREPC TC promotes an environment for CREPC members and staff to collaborate on the critical transmission coordination and development issues in the WI by expressly incorporating the diversity of perspectives from Western states and provinces. The group began meeting in January 2024 and has robust participation from states throughout the West.

The CREP TC intends to assess how that plan develops and evaluate whether additional planning studies might be necessary. The CREPC TC has contracted with the Energy Strategies consultancy to develop an interregional transmission cost allocation framework that might support and even promote multi-state transmission projects throughout the West. The diversity of states' input around cost allocation considerations is expected to meaningfully shape a planned whitepaper from Energy Strategies on a potentially novel framework.

Interconnection-Wide Transmission Assessments Emerge

While western states mobilized on the interregional transmission front through CREPC's transmission collaborative in 2023, a broader initiative led by the Western Power Pool, known as WestTEC, has developed with the main goal of the coalition of growing the recognition more transmission is needed and the current approach to planning is "insufficient". A specific concern is that no regional transmission projects have been built and interregional planning has been virtually nonexistent, despite Federal Energy Regulatory Commission (FERC) Order 1000, which was designed to encourage regional transmission planning. WestTEC is exploring a new approach for West-wide transmission planning that will result in an actionable transmission plan to address regional and inter-regional needs. It seeks to include participants from across the WI and differs from FERC Order 1000 because it will not address cost allocation, is not compliance driven, is voluntary and is a single Interconnection-wide process.

WestTEC has focused its early effort on establishing leadership, funding and governance; its primary committees include Steering, Regional Engagement and WestTEC Assessment Technical Team. With adequate funding available it will contract with a consultant to undertake Interconnection-wide power flow and production cost modeling focusing on distinct 10-year and 20-year futures.

Continent-wide Transmission Assessment Mandated by Congress

Unprecedented work is underway at the national level, spurred by provisions of Section 322 of the federal Fiscal Responsibility Act. In this statute, Congress directly acknowledged the need for improved ability to move power among different sub-areas and regions of the country. Known as the Interregional Transfer Capability Study (ITCS) and led by the North American Electric Reliability Corporation (NERC), the assessment is being conducted by the six regional entities, including WECC, and the transmitting utilities. Phase 1 of the study is determining the total transfer capability between neighboring transmission planning regions; it will rely on a modeling tool never used in the WI before and is scheduled for completion in July 2024. A map of the ITCS source and sink areas for the WI study shows these areas do not correspond to the FERC Order 1000 planning regions that have not succeeded in identifying any interregional projects in well over a decade of planning.

The ITCS is important to California reliability in future years because Phases 2 and 3 of the study will consider "prudent" additional transfer capability between neighboring areas to resolve reliability issues and will identify mechanisms to achieve and sustain the identified transfer capability and enhancements. This could result in the federal government taking action to increase transfer capability in the WI, allowing improved flows of import/export resources particularly in times of energy emergencies or extreme weather events affecting multiple sub-areas. NERC is to deliver the ITCS to FERC December 2, 2024, including the Phase 2 and 3 identification of additional transfer capability needs and mechanisms.

Regional Governance: Exploring Options to Achieve Widest Western Engagement

As stated previously, the West has made previous attempts to establish wholesale regional market entities through time-intensive collaborations with names such as InDeGo, RTO West, Grid West and Desert STAR. Disagreements between various states and utilities over governance, functions, funding and timing caused all of these to fail. One exception to failure is California's ISO, created by the Legislature as a one-state independent system operator for California's investor-owned utilities. The California ISO has functioned well as a BA for most of California for over 20 years. It has further provided an institutional mechanism and capability for all western balancing authorities to voluntarily contract for sub-regional market and reliability services such as through the WEIM. Also of importance is RC West, a California ISO administered independent entity providing reliability coordination functions for over 80 percent of the WI through voluntary contracts as authorized by NERC.

Because the California ISO has provided technical capability and opportunity beyond just California's borders, a persistent complexity point has been the current California ISO governance model in which the California governor appoints a five-member Board of Governors. This one-state approach has understandably proven to be a challenge to initiatives seeking to further expand regional markets and services. Over time, Western stakeholders have worked hard to find innovative "regional" governance approaches; many of these have been implemented and are now being further explored by multiple entities, as described below.

Evolving WEIM/EDAM Governance

WEIM is led by a Governing Body consisting of five independent members nominated by a sector-based committee of Western representatives from diverse elements of the electricity system. The governance of WEIM has a complex set of responsibilities divided into categories of primary authority and joint authority. These authorities may be shared with and are delegated by the California ISO Board of Governors. Most recently this Governing Body was redesignated as the WEIM/EDAM Governing Body. Input to this entity comes from the Body of State Regulators an advisory group of state regulators, one from each state that has a participant in the WEIM. This group is funded by the WEIM utilities and provided technical staff support from the Western Interstate Energy Board.

While the innovative, shared-authority model has served the WEIM well, key points of debate exist. First is the appointment of the California ISO Board of Governors by the California Governor. Second is the dispute resolution process in which disagreements between the WEIM and California ISO Board are remanded to the stakeholder process. The third complaint is that, though the stakeholder process is highly regarded and transparent and well-represented and organized, the ultimate final recommendations are made by the California ISO staff not the stakeholder groups. Finally, the Board of Governors has Section 205 FERC filing rights for proposed tariffs or tariff revisions.

Markets + Governance by Stakeholders, Participants, and the SPP

Participants in the Markets + development process regularly note an appreciation of the governance structure provided by the SPP approach. Generally, this structure promotes participant-led collaboration on design and development proposals through taskforces and working groups. Design and development decisions advance through participant votes at the committee level.

The initial phase of the Markets+ effort took guidance from two committees, the State Committee and the Participant Executive Committee. The State Committee served to provide input from state regulators and energy leadership on key issues and critical decisions arising in the development process. The Participant Executive Committee served to coordinate the efforts of the task forces and working groups to arrive at a market design and associated tariff to put before participants for approval. The committees operated with oversight from the Interim Markets+ Independent Panel, comprised of three members of the SPP independent board of directors. This interim panel serves in a transitional role until such time that Markets+ becomes operational, triggering tariff provisions creating a new Independent Panel separate from the SPP board.

Interconnection Reliability Risks: Evaluating, Ranking, and Prioritizing

WECC Reliability Risk Committee Characterizes and Ranks Interconnection Risks; WECC Board Approves 2024-26 Reliability Risk Priorities

An important first-time initiative emerged from WECC in 2023-24 as the Reliability Risk Committee, one of WECC's two technical member committees, implemented its charter requirements to develop and maintain a ranked list of risks to WI reliability and to identify mitigation. To accomplish this, WECC staff developed descriptions of risks in 10 categories: cybersecurity, changing resource mix, extreme natural events, frequency performance, grid transformation, inverter-based resources, infrastructure, personnel, physical security, and RA. Thirty-one risks were identified, their severity quantified and then ranked from highest to lowest threat to the WI.

This ongoing process has resulted in preliminary identification of a list of risks meriting top focus for mitigation in 2024-25. Toward this end, WECC staff will be developing mitigation plans for eleven major risks falling into four of the above categories:

- Extreme Natural Events: large and prolonged heat waves, cold weather preparedness, wildfire
- Grid Transformation Inverter-based Resources: inadequate interconnection requirements, modeling quality issues, system restoration
- Grid Transformation Changing Resource Mix: generation resource mix impacts on transmission congestion
- Infrastructure: supply chain constraints
- Cybersecurity: malware, zero-day exploit, insider threat

WECC Board Biennial Reliability Risk Priorities. Based on the Risk Register and stakeholder input, every other year, the WECC staff and Board undertake a review of the reliability risks the west faces. This draws on annual work completed by NERC and the Reliability Risk Committee's recent Risk Register. A workshop was held in March, WECC staff has posted a working paper identifying 10 top risks for review and comment. The Board approved the Reliability Risk Priorities on June 12, 2024. WIRAB concurred on the approval of five priorities that will guide the work of WECC in the 2024-26 timeframe:

1. Aridification and associated natural events;
2. Impact of inverter-based resources;
3. Lack of coordinated resource and transmission planning;
4. Modeling quality and input validation; and
5. Potential effects of energy policies in the West

WIRAB 2025 Business Plan and Budget

As an integral component of its annual budget process, WIRAB identifies "Strategic Initiatives" for which it seeks funding through NERC and FERC's review of the regional entities' proposed expenditures and assessments imposed on load serving entities in the WI. This process begins in April and concludes with FERC approval in early November 2024. WIRAB staff's proposed initiatives for 2025 are:

- **Transmission Planning (WestTEC):** Advise WECC to work collaboratively with the Western Power Pool and Western stakeholders to develop an investment-grade transmission plan that effectively improves reliability in the WI.
- **Inverter-based Resource Risk:** Advise WECC to work collaboratively with Western regulators and stakeholders to address and proactively mitigate risks associated with the uncoordinated interconnection of inverter-based resources in the WI.
- **Interregional Transfer Capability:** Advise WECC regarding a process for ongoing assessments and prudent upgrades for inter-regional transfer capabilities in the WI to ensure reliable power flow when the system is stressed.
- **Extreme Weather Event Analysis:** Advise WECC to conduct a systematic review of recent extreme weather events that have tested the grid, focusing on the challenges of maintaining grid reliability during increased demand, unexpected outages, system stress, and near-miss incidents in the WI.
- **Grid Enhancing Technologies for Reliability:** Advise WECC to assess the reliability implications of innovative grid solutions used to maximize the potential of the existing transmission system as utilities modernize the grid in the WI.

The draft initiative written descriptions were included in the first draft Business Plan and Budget (BP&B) May 1, 2024, and were formally approved by unanimous consent on June 13, 2024.

APPENDIX C: Gas Plant Performance

Power plant performance represents a critical aspect of system reliability. Previous staff analysis[81] explored this relationship following the 2020 heat events. In this analysis, staff analyzed power plant performance during the summer reliability months of July, August and September for the years 2021-2023. The analysis focuses on the availability aspect of performance as represented by historical data on capacity outages and derates for resources in the California ISO system. Generally, a capacity "outage" represents the maximum operational capacity of an entire facility going out of service. A capacity "derate" is usually more variable and tied to environmental conditions and can be thought of as a partial outage. This work uses the terms "outage" and "derate" interchangeably.

Findings

Staff developed the following findings:

- Reaching conclusions about system-wide outage trends to inform planning requires very careful analysis. Facility outages occur for a wide range of reasons at different times throughout the year, across seasons and intraday. Outages are not inherently bad if timed effectively, as maintenance is required for long-term availability of facilities. Existing data sources are not easy to interpret and may have incomplete or inconsistent information.
- Heat events in the study period were associated with increased daily peak loads of about 21 percent, on average.
- Heat events in the study period were associated with increased daily maximum derates on natural gas resources, during net peak hours of nearly 300 MW, about 9 percent, on average for that resource group.
- California ISO DMM reports for the years 2020 through 2023 show that aggregate outages in September increased year over year between 2020 and 2022, then decreased slightly in 2023 due to milder ambient temperatures and lower loads.

Data Collection and Analysis

Staff constructed a data set on California ISO resource outages from publicly available Prior Trade Date Reports published by the California ISO covering the summer months of all available years, 2021 – 2023. Working with the Prior Trade Date Report outage data proved more challenging than expected. Extended outages and overlapping outages made the

81 See "*Electric System Reliability and the Recent Role of California's Fossil Fleet*", https://www.energy.ca.gov/sites/default/files/2021-10/CEC-700-2021-002.pdf

handling of multiple Prior Trade Date files particularly difficult. Using the constructed data set, staff takes two views of capacity derates to better understand trends in outages:

1) **Maximum Hourly Derated Capacity**: The maximum instantaneous derated capacity in an hour. For example, derates of 20 MW from 17:00 to 17:50 and 300 MW from 17:51 to 18:00 would have a maximum hourly derate of 300 MW. This measure considers sub-hourly peak derates and is effectively instantaneous.
2) **Average Hourly, Duration Weighted, Derated Capacity**: The average derated capacity over an hour. If a derate amount changes within an hour, then each derate value is weighted by its minutes of duration to show an average derate over the hour. From the previous example, the average hourly derate would be:

$$20MW*(50/60) + 300MW*(10/60) = 17\ MW + 50\ MW = 67\ MW.$$

In addition to covering only the summer months of the years 2021 through 2023, much of this analysis is further restricted to the most critical hours of the day, from a grid operations perspective. The net peak hours, which span the period from 16:00 to 21:00, represent a portion of the day when grid conditions are more likely to be stressed and natural gas units are needed to ramp up and replace the declining early evening solar supply. A focus on these hours is not unique to this analysis. The CPUC, in its RA Slice of Day implementation, found that the evening peak hours in summer months have the tightest generation supply.[82] For summer months, CPUC RA assessment rules apply to the hours from 16:00 through 21:00 for the 2024 compliance year.[83]

Figure 20 shows the sum of maximum hourly derated capacity and the sum of average hourly derated capacity over the net peak hours of 16:00 to 21:00 for September 2022. For each pair of bars, the solid bar shows the monthly total of the maximum hourly derated capacity over the net peak hours while the hashed bar shows the monthly total of average hourly derated capacity over the net peak hours. Figure 20 illustrates that natural gas resources experienced the highest levels of maximum hourly derated capacity[84] and average hourly derated capacity, followed by hydroelectric resources. This observation relates to installed capacity measures, as natural gas-powered resources make up the largest share of the California ISO resource fleet.[85]

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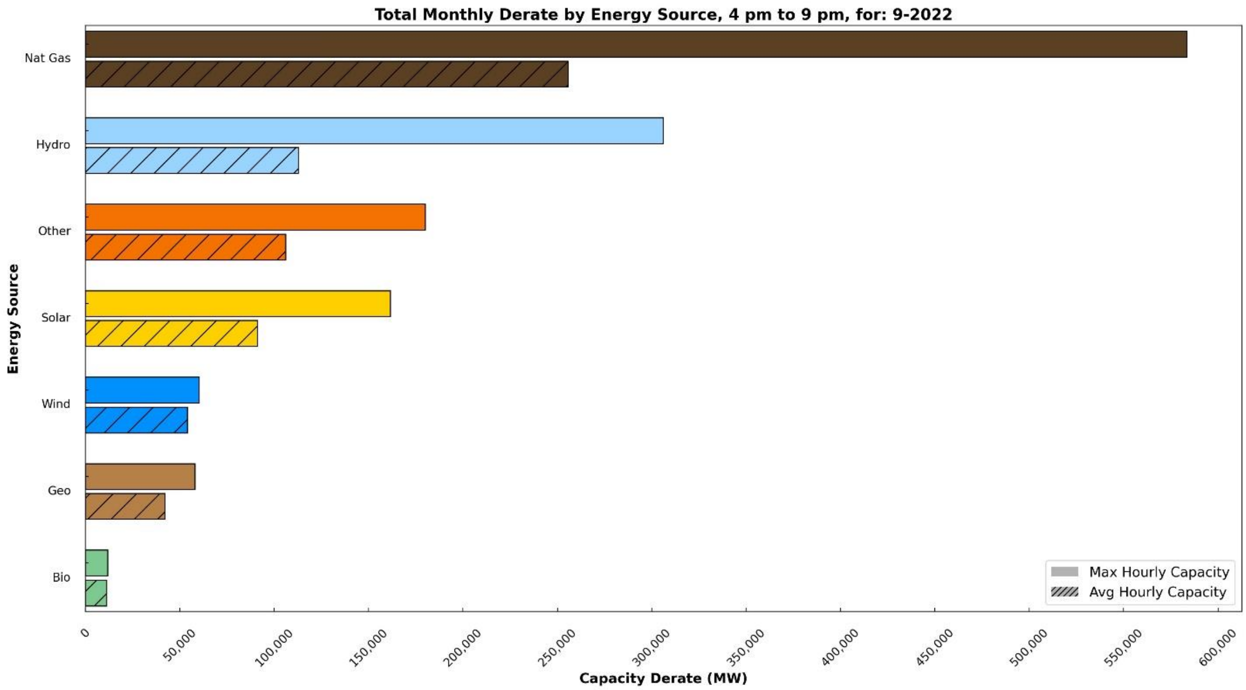
82 California Public Utilities Commission, *Energy Division Report on RA SOD Implementation and Year Ahead Showings*, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/energy-division-report-on-ra-sod-implementation-and-year-ahead-showings.pdf.

83 California Public Utilities Commission, *Final 2024 Resource Adequacy Guide*, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/guides-and-resources/final-2024-ra-guide-clean.pdf.

84 In August 2023, solar PV resources experienced the second largest total monthly derate. All other months, hydro resources experienced the second largest derate.

85 In the California ISO controlled grid, natural gas resources comprise over 30,000 MW of nameplate capacity with combined cycle plants accounting for about half of that total.

Figure 20: Total Derate by Energy Source



Source: CEC staff analysis of California ISO data

For additional detail on total derates beyond the energy source, the staff-constructed data set also allowed for categorization by resource technology types. This additional detail proved useful in analyzing resource trends within the natural gas energy source category.

Figure 21 shows the monthly total derate measure in the same style as the previous figure but categorized by resource technology type instead of energy source. Using the more detailed categorization, the figure charts the sum of maximum hourly derated capacity and the sum of average hourly derated capacity over the net peak hours of 16:00 to 21:00 for September 2022. Combined cycle natural gas plants show the most total derated capacity in all months except for August 2021, where hydroelectric resources had more total derated capacity due to drought conditions. Many combined cycle units experience large capacity derates for short periods of time, often proportional to their larger unit size. Combined cycle natural gas plants represent about half of the total natural gas nameplate capacity in California ISO.[86]

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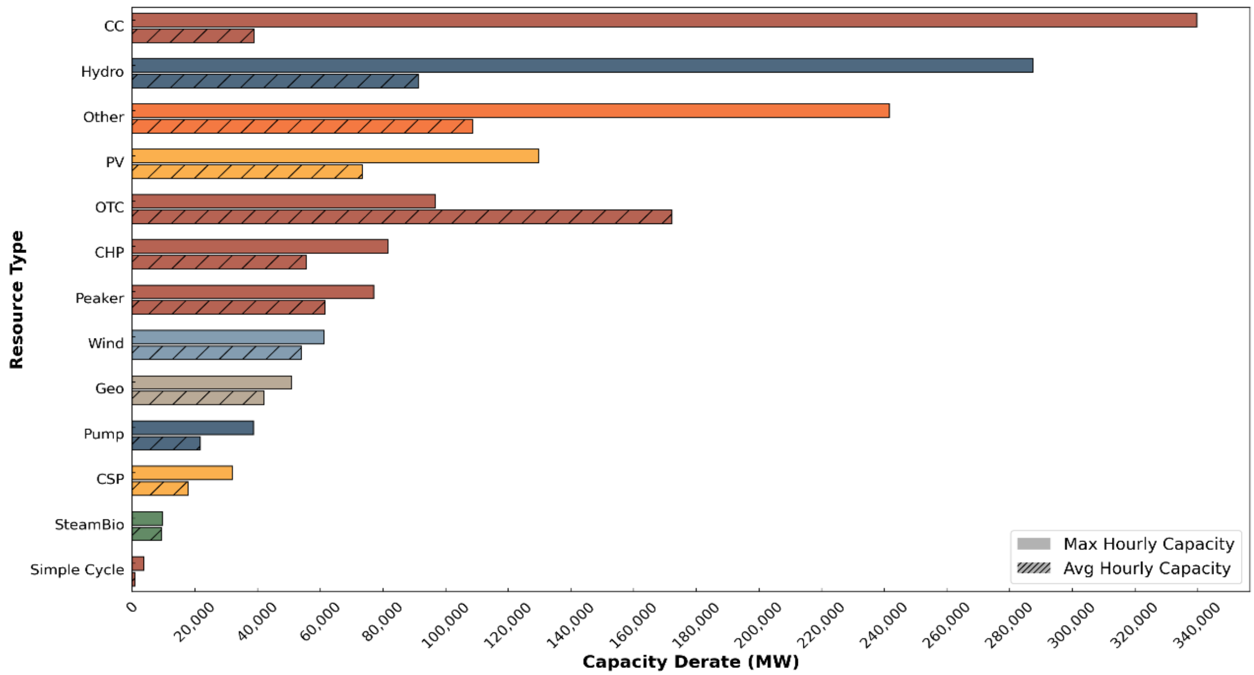
86 California ISO OASIS master gen file, downloaded July 2023.

Figure 21: Total Derate by Resource Type, September 2022



Source: CEC staff analysis of California ISO data

Both Figure 20 and Figure 21 show that monthly totals for maximum hourly derated capacity across the net peak hours can differ significantly from monthly derated average hourly capacity. There are multiple ways to view derated capacity depending on the research question and needed analysis. Again, staff considers two derate metrics in this analysis: maximum hourly derated capacity and average hourly derated capacity. The maximum hourly derated capacity represents the peak derated capacity at any point within the hour while the average hourly derated capacity represents derated capacity, weighted by the duration of the derate, averaged over the whole hour.

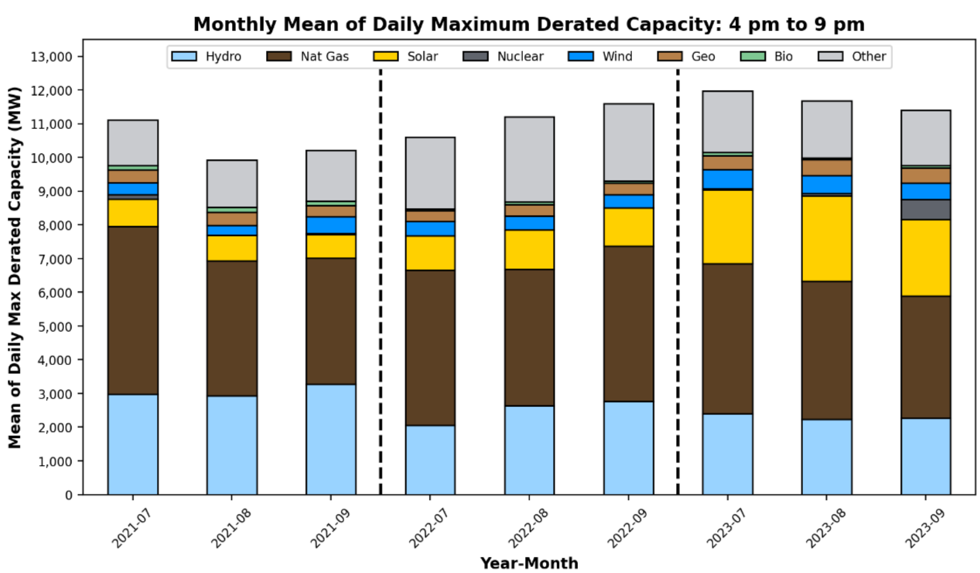
A list of descriptions for resource types appearing in Figure 21 follows:

- CC: Combined cycle natural gas plant that uses both a gas turbine and a steam turbine in tandem to generate electricity
- Hydro: represents hydroelectric power plants
- Other: this category is for resources where California ISO data had no unit type specified
- PV: solar PV resources
- One-through cooling (OTC): OTC units on the California coast that use ocean water for power plant cooling
- CHP: combined heat and power plants usually supporting cogeneration operations
- Peaker: fast ramping natural gas plants (aeroderivative) used to meet load on short notice
- Wind: power plants that generate electricity through wind turbines

- Geo: geothermal power plants (both flash and binary)
- Pump: pump storage hydroelectric plants
- CSP: concentrating solar-thermal power that uses collector mirrors to reflect the sun to heat up a fluid to power a turbine
- SteamBio: biomass and biogas power plants that burn biofuels to spin a steam turbine to generate electricity
- Simple Cycle: natural gas power plant that runs hot gas through a turbine to generate electricity; these units generally do not have fast start capability like peakers (aeroderivative)

Figure 22 shows monthly averages of the maximum daily capacity derates as represented by the maximum hourly capacity derate observed during the net peak hours of 16:00 to 21:00 for each day. On average, the daily maximum derated capacity of natural gas resources increased by 4 percent from 2021 to 2022 and decreased by about 8 percent from 2022 to 2023. The chart shows that the severity of total outages from all energy sources has increased in summer months: a 7 percent increase from 2021 to 2022, and another 5 percent increase from 2022 to 2023. Figure 22 compares well with a figure regularly featured in outage reporting from the California ISO.[87] However, Figure 22 has a larger percentage of total derate coming from the 'other' fuel category when compared with the similar California ISO figure.

Figure 22: Monthly Capacity Derate by Energy Source, Maximum Hourly

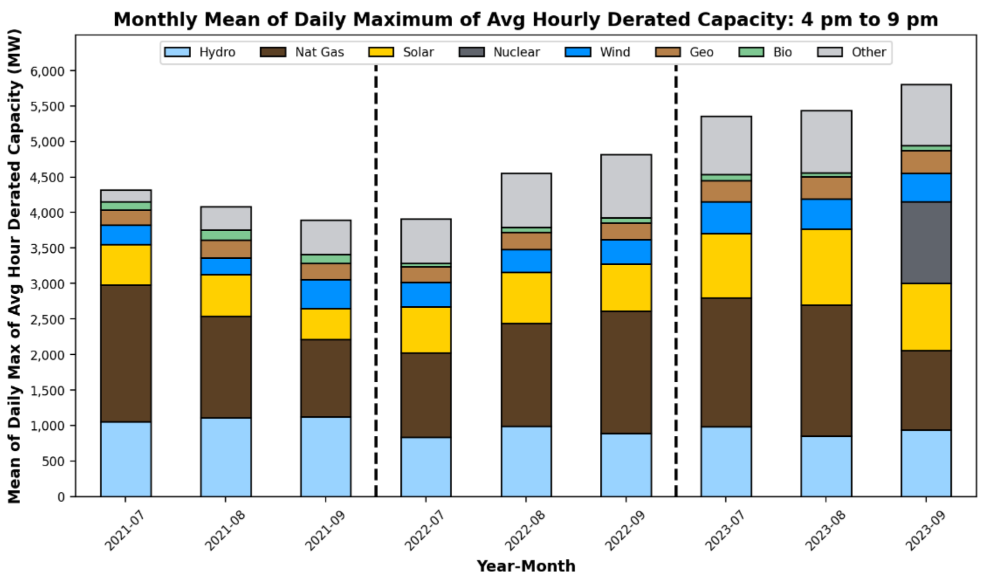


Source: CEC staff analysis of California ISO data

87 See Figure 1.26, http://www.caiso.com/Documents/2022-Annual-Report-on-Market-Issues-and-Performance-Jul-11-2023.pdf

Figure 23 shows the monthly averages of the maximum daily capacity derates as represented by the average hourly capacity derate (weighted by duration of derate) observed during the net peak hours of 16:00 to 21:00 for each day.

Figure 23: Monthly Capacity Derate by Energy Source, Average Hourly



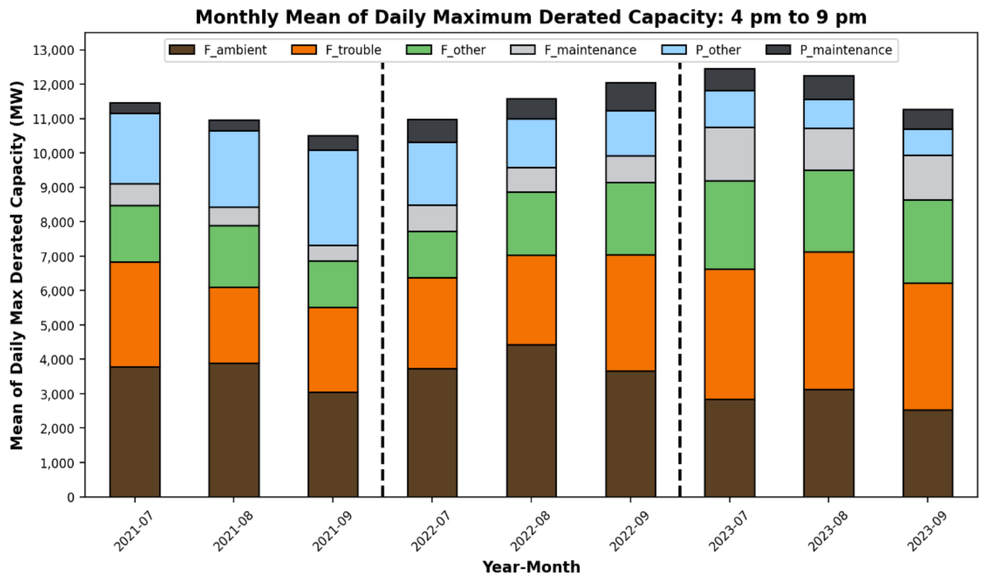
Source: CEC staff analysis of California ISO data

Figure 23 shows that natural gas resources, under this metric, exhibit significantly more variability. During the summer months from 2021 through 2023, monthly average capacity derates for natural gas resources decreased by 2 percent from 2021 to 2022 and an increased 10 percent from 2022 to 2023. The total of monthly average derates across all energy sources increased from 2021 through 2023: an 8 percent increase from 2021 to 2022, and a 25 percent increase from 2022 to 2023. Figure 22 and Figure 23 highlight different aspects of a general trend showing that outages and derates during summer months have become more severe over the last few years.

The next two charts are similar to the previous pair of figures (Figure 22 and Figure 23), but instead show derates by type of outage rather than by energy source. In the charts, data labels beginning "F_" represent forced outages, meaning that the outage was submitted with less than seven days advanced notice to California ISO. Data labels beginning "P_" in the charts mean the outage was planned, meaning that the outage was submitted with at least seven days of advanced notice to California ISO.

Figure 24 shows the monthly average of the daily maximum capacity derates as represented by the maximum hourly capacity derated capacity observed during the net peak hours of 16:00 to 21:00 for each day and categorized by outage type. Forced outages make up most of the derates, with outages from ambient conditions and plant trouble combined, being more than half of total outages. Ambient outages decreased slightly from 2021 through 2023 while plant trouble outages increased by 48 percent from 2021 to 2023. Planned outages showed a small increase but remained roughly similar over the study period.

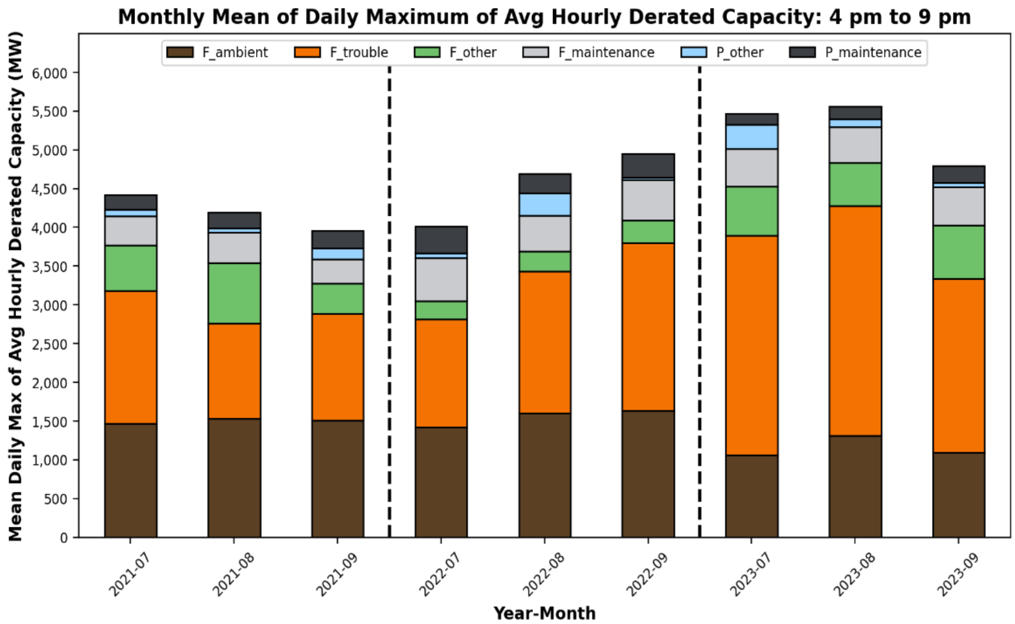
Figure 24: Monthly Capacity Derate by Outage Type, Maximum Hourly



Source: CEC staff analysis of California ISO data

Figure 25 utilizes the style of Figure 24, but instead shows monthly averages of the maximum daily capacity derates as represented by the average hourly capacity derate (weighted by duration of derate) observed during the net peak hours of 16:00 to 21:00 for each day and categorized by outage type. This figure shows that plant trouble and ambient outage categories comprise most of total outages, and the magnitudes of these outage types increase during summer months year over year. Plant trouble and ambient outages combined, account for 55 percent, on average, of total outages - inclusive of both forced and planned outages. Outages from these two categories are roughly 10 percent higher in 2022 and 2023 compared to 2021. These graphs show that most outages during summer months are of the forced type and are due to ambient temperature derates and plant trouble outages, which generally have become more severe over the last few years.

Figure 25: Monthly Capacity Derate by Outage Type, Average Hourly



Source: CEC staff analysis of California ISO data

Comparison of Event versus Non-event Days:

California ISO event declarations in summer months roughly correspond with heat events that bring heavy loads and stressed system conditions. California ISO can declare, and issue notice of, official operating events for any conditions that threaten electric or transmission grid capability (extreme heat, equipment failure, etc.). These declarations include flex alerts, restricted maintenance operations (RMO), and different levels of EEAs.[88] This section defines a California ISO Event Day as any day upon which the grid operator has issued one or more alert, warning, or emergency operations notice to its market participants.

For reference, Table 17 at the end of this appendix lists the dates upon which the California ISO issued any RMO, alert, warning, or emergency notices during the study period of 2021 through 2023 for the months of July, August and September. On May 1, 2022, California ISO changed some emergency alert definitions to align with federal reliability standards. The "Warning" and "Stage 1-3" emergency notice designations were incorporated into various EEA designations, although there were differences that did not translate one for one.

During the study period, daily peak loads averaged nearly 37 GW. On non-event days, which comprise most days in the study period, daily peak loads averaged slightly lower at 36 GW. Over the 37 days of the study period associated with California ISO Event Day declarations, daily peak loads averaged over 43 GW, about 21 percent higher than non-event days.

88 California Independent System Operator, *Emergency Notifications Fact Sheet*, available at: https://www.caiso.com/Documents/Emergency-Notifications-Fact-Sheet.pdf.

Peak load levels are not the only aspect of the system affected by heat events. These stressed conditions can also impact resource performance. In particular, the performance of flexible, dispatchable capacity, primarily from resources fueled by natural gas, can be affected. During the study period, the daily maximum derate averaged nearly 3,300 MW for these resources, with no significant change in the metric during non-event days. However, during California ISO Event Day declarations the average daily maximum derate increased by 9 percent to just over 3,600 MW for natural gas fueled resources. Nearly all the increase was attributable to outage type categories related to ambient derates.

To better understand how California ISO event days affect natural gas resources, staff compared derated capacity for event and non-event days. This is a simple comparison, and a more detailed look at extreme weather days could provide additional insights. Table 17 compares the average of the maximum daily derated capacity of natural gas (all natural gas technologies combined, for maximum hourly derated capacity) for event and non-event days. The table shows that most months have higher average maximum daily derated capacity during event days. Notably, August 2023 and September 2021 had less derated capacity during event days despite being the months containing the respective peak load days for those years.[89] See Table 17:

Table 17: Average of Maximum Daily Derate of Natural Gas Resources

Year	Month	Non-Event Day Total Derate (MW)	Event Day Total Derate (MW)	Percent Difference (Total)	Non-Event Day Ambient Derate (MW)	Event Day Ambient Derate (MW)	Percent Difference (Ambient)
2021	7	3,872	4,149	7.2%	1,241	1,407	13.4%
2022	7	3,619			1,844		
2023	7	3,682	4,150	12.7%	1,259	1,360	8.0%
2021	8	2,982	3,080	3.3%	1,223	1,406	14.9%
2022	8	3,067	3,169	3.3%	1,610	1,670	3.8%
2023	8	3,516	3,196	-9.1%	1,267	1,556	22.8%
2021	9	2,729	2,717	-0.4%	1,078	1,402	30.0%
2022	9	3,355	4,181	24.6%	1,281	2,228	73.9%
2023	9	2,987			1,030		

Source: CEC staff analysis of California ISO data

Table 17 also shows ambient derated capacity. Considering just ambient derates, in the summer months, natural gas resources appear to have more capacity derated during event days compared to non-event days. On average, August experienced 14 percent more derated capacity during event days and September experienced over 50 percent more. One explanation for the elevated metric during the month of September is the tendency for this

89 July 2022 and September 2023 had no event days.

month to experience more extreme temperature conditions in the first few weeks of the month, while the latter half of the month tends to be much milder. Such conditions later in September can raise derated capacity levels as resources have more opportunity to perform maintenance once stressed summer operating conditions subside.

Table 18 below[90] compares event day[91] and non-event day capacity derates by natural gas technology type[92]. Although combined cycle plants have the largest daily maximum capacity derates, as the most prevalent natural gas facility type, OTC units, followed by simple cycle facilities show the largest percent derated capacity increase from non-event to event days. In the summer months of 2023, the maximum daily derated capacity of OTC units was 450 percent larger for event days compared to non-event days. For simple cycle facilities, the difference was 63 percent higher, and over 40 percent higher for combined cycle plants.

Table 18: Average of Maximum Ambient Daily Derate of Natural Gas Resources, By Technology

		CC (MW)	CC (MW)	CC (MW)	SC (MW)	SC (MW)	SC (MW)	FT (MW)	FT (MW)	FT (MW)	OTC (MW)	OTC (MW)	OTC (MW)
Year	**Month**	**Non-Event**	**Event**	**Percent Difference**	**Non-Event**	**Event**	**Percent Difference**	**Non-Event**	**Event**	**Percent Difference**	**Non-Event**	**Event**	**Percent Difference**
2021	7	858	995	16%	246	295	20%	106	99	-6%	32	24	-23%
2022	7	857			240			106			16		
2023	7	774	988	28%	202	286	42%	96	91	-5%	5	34	650%
2021	8	1,429	981	-31%	323	271	-16%	88	93	6%	5	53	891%
2022	8	1,214	1,199	-1%	283	294	4%	103	108	5%	21	70	242%
2023	8	906	1,452	60%	240	441	83%	79	112	41%	65	227	248%
2021	9	916	957	5%	237	280	18%	89	92	3%	34	22	-34%
2022	9	803	1,018	27%	316	338	7%	107	120	12%	50	83	68%
2023	9	729			215			93			5		

Source: CEC staff analysis of California ISO data

Once again, looking at just California ISO event days, rather than the specific event types and event totals for each day, represents a simplistic categorization for extreme heat days that does not consider that some event days may be more severe than others. Staff could consider

90 The first row of the table utilizes the following abbreviations to maximize the use of available space: CC – Combined Cycle, SC – Simple Cycle, FT – Frame Turbine, OTC – Once Through Cooling.

91 There were no events declared in the months of July 2022 and September 2023.

92 The ‘Other’ category includes reciprocating engines and was left out as it was small compared to technologies featured in the table.

more detailed event day categorizations in future analyses to provide some type of magnitude for different event days.

California ISO Outage Reporting

The California ISO DMM provides independent oversight and analysis of the California ISO market. The DMM Annual and Quarterly Reports for the years 2020 through 2023 show that aggregate outages in September increased year over year between 2020 and 2022, then decreased slightly in 2023 due to milder temperatures and lower loads.

Reporting on outages from California ISO groups besides the DMM, usually performed by California ISO Market Performance group and Market Design group staff, is almost exclusively focused on the RA program perspective. Since there are some resources without any RA capacity and other resources with only partial RA capacity, outage reporting with this limited focus does not extend to the entire California ISO fleet and may be inappropriate to support outage analysis needed for situations when every MW counts.

Staff includes below California ISO outage definitions excerpted from official documentation. It should be noted that these definitions do not highlight certain submittal timing criteria maintained by the grid operator to differentiate between planned outages and forced outages. In particular, all outages submitted to the California ISO outage management system less than seven days in advance of the outage are deemed to be forced outages.

California ISO Outage Definitions[93]

- Planned Outage - A period of time during which a Generation or Transmission Operator (i) takes its transmission facilities out of service for the purposes of carrying out routine planned maintenance, new construction work or for work on de-energized and live transmission facilities (e.g., relay maintenance or insulator washing) and associated equipment; or (ii) limits the capability of, or takes out of service, its generating unit or system unit for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work.
- Forced Outage - An outage for which sufficient notice cannot be given to allow the outage to be factored into the Day-Ahead Market or RTM bidding processes. California ISO-defined forced outages include the following (among others): annual, monthly, short-term, or other use limit reached, transmission induced, plant maintenance, plant trouble, ambient due to temp, ambient not due to temp, ambient due to fuel insufficiency, power system stabilizer, new generator test energy, environmental restrictions, contingency reserves management.

Source: CEC staff analysis of California ISO data

93 California Independent System Operator, *Outage Management*, available at: https://www.caiso.com/market/Pages/OutageManagement/Default.aspx.

APPENDIX D: Gas Demand Forecast Methodology

The methodology for the gas demand forecast for SoCalGas involves several steps to ensure robust short-term forecasting of monthly average and peak-day demands across customer classes and temperature scenarios. Here is a summary of the key steps involved.

Exploratory Data Analysis

This step involves analyzing historical data to identify trends, patterns, and key explanatory variables for gas demand. Gas demand is driven primarily by temperature, directly in the winter and indirectly in the summer. Gas demand is higher on cold winter days to meet heating needs. Gas demand is also higher on hot summer days as it is used for electricity generation to meet summer cooling loads. The data exhibits non-linear trends, seasonality, lagging temperature effects, and variations in demand based on weekdays, holidays, and seasons. Customer classes exhibit different temperature effects, with the core customers peaking during winter and the electric generation peaking during summer. The other customer classes, including noncore, transport to SDG&E, and others, are not significantly affected by temperature and seasonality.

Data Sources

NOAA provided historical daily maximum and minimum temperature data for 30 years (1994-2023). Temperature data for the forecast period (2024-2026) comes from downscaled bias-corrected global climate model projections available through the Cal-Adapt Analytics Engine.[94] Climate change is anticipated to increase average temperatures, reducing heating loads but increasing cooling loads.

These temperatures come from relevant weather stations in SoCalGas's service area, including Burbank, Long Beach, Santa Barbara, Bakersfield, and Riverside. The temperatures are a daily weighted average, weighted by population to represent its service area.

SoCalGas provided daily gas demand data disaggregated by customer classes from 2017 to 2022 and aggregated daily data from 2010 to 2023 was sourced by CEC from the SoCalGas Envoy® website.

Modeling

The modeling step adopts a probabilistic additive linear regression model, which extends traditional linear regression techniques by incorporating probabilistic principals to capture

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94 Ongoing research supported by EPIC has delivered a suite of hybrid (statistical-dynamical) downscaled, bias-corrected projections over California at a 3 kilometer by 3 kilometer resolution. This effort is supported by several EPIC applied research efforts, including the Cal-Adapt Analytics Engine which provides analytic support for localizing projections to nearby weather stations based on historical observed data that provide a basis for bias correction.

factors, such as trends, seasonality, and drivers such as historical temperatures and calendar variables and other variables.

The daily data are pre-processed by resampling to monthly averages and log-transforming for symmetry and to reduce variability, serial correlation, and non-linearity. The impact of temperature on gas demand is quantified using average temperatures, which fit better than any other temperature-derived variables, as a third-degree polynomial.

Lagging temperature effects are accounted for using a weighted average of three consecutive daily temperatures: 6/10 of the current day's temperature, 3/10 of the previous day's temperature, and 1/10 of the temperature two days prior. The data is partitioned into training, validation, and test sets, and hyperparameters are tuned to optimize model performance according to standard evaluation metrics, including out-of-sample cross-validation.

Forecasting

The analysis employs separate probabilistic additive modeling to forecast monthly average and peak-day gas demands up to three years ahead. The monthly model uses monthly data as an input, whereas the peak-day model uses daily data. The peak day model also incorporates calendar drivers, which are factors related to a specific day of the month or year, such as holidays, weekends, or seasonal patterns. In contrast, these factors do not apply to the monthly model. Both models use the same fundamental methodology and capture the relationship between gas demand and demand drivers and reflects gas demand based on projected temperature conditions.

From the projected temperature conditions, the 50 percent, 10 percent, and 2.86 percent probabilities of exceedance are calculated by identifying the 50th, 90th, and 97.14th percentiles, respectively. These exceedance probabilities were selected after a randomly drawn daily values simulation from a projected temperature model pool.

After identifying the relationship between total gas demand and the demand drivers, the temperatures corresponding to the exceedance probabilities are used as inputs to the model to forecast gas demand under each condition.

Core and electric generation profiles as a percentage of total gas demand are modeled and projected separately, following the probabilistic additive models described above. The projected profiles are then applied to the projected total gas demand values to derive the demand by customer class for the 3-year forecast period. The remaining customer class profiles and projected gas demands are scaled based on core and electric generation values.

APPENDIX E: Acronyms and Abbreviations

AB - Assembly Bill

ALJ - Administrative Law Judge

BAA - Balancing Authority Area

BA - Balancing Authority

BANC - Balancing Authority of Northern California

BCF – Billion Cubic Feet

CalGEM - California Department of Conservation's Geologic Energy Management Division

CCA - Community Choice Aggregators

CERRO – California Energy Resource and Reliability Outlook

CEC - California Energy Commission

CED – California Energy Demand Forecast

CGR – California Gas Report

CPC - Climate Prediction Center

CPUC - California Public Utilities Commission

CREPC - Committee on Regional Electric Power Cooperation

CREPC TC - Committee on Regional Electric Power Cooperation Transmission Collaborative

DCPP - Diablo Canyon Power Plant

DMM - Department of Market Monitoring

DOE - Department of Energy

DR - Demand Response

DSGS - Demand-Side Grid Support

EIA - Energy Information Administration

ELRP - Emergency Load Reduction Program

ESSRRP - Electricity Supply Strategic Reliability Reserve Program

EDAM – Extended Day-Ahead Market

FERC - Federal Energy Regulatory Commission

GADS - Generating Availability Data System

GHG - Greenhouse Gas

GW - Gigawatt

GWh - Gigawatt-hour

IEPR - Integrated Energy Policy Report

IID – Imperial Irrigation District

IMIP - Interim Markets + Independent Panel

IOU - Investor-Owned Utility

IRP - Integrated Resource Planning

ISO - Independent System Operator

ITCS - Interregional Transfer Capability Study

kWh – Kilowatt Hour

KV - Kilovolt

LADWP - Los Angeles Department of Water and Power

LOLE - Loss of Load Expectation

LSE - Load-Serving Entity

MAVRIC - Multi-Area Variable Resource Integration Convolution

MMcfd - Million Cubic Feet per Day

MW - Megawatts

MWh - Megawatt-hour

NERC - North American Electric Reliability Corporation

NREL - National Renewable Energy Laboratory

NVE – Nevada Energy

NQC – Net Qualifying Capacity

OTC – Once-Through Cooling

PACW - PacifiCorp-West

PGE - Portland General Electric

PG&E – Pacific Gas and Electric

PLEXOS - Power System Simulation for Long-Term Planning

POU - Publicly Owned Utility

PR - Public Resources Code

PRM - Planning Reserve Margin

PSP - Preferred System Plan

PV - Photovoltaic

RA - Resource Adequacy

RMO - Restricted Maintenance Operations

ROD - Record of Decision

RPG – Regional Planning Groups

RPS - Renewable Portfolio Standard

RTO – Regional Transmission Organizations

SB – Senate Bill

SOD – Slice of Day

SoCalGas – Southern California Gas

SPP - Southwest Power Pool

SMUD - Sacramento Municipal Utility District

SWIP - Southwest Intertie Project

TED - Tracking Energy Development

TID - Turlock Irrigation District

WECC - Western Electricity Coordinating Council

WEIM - Western Energy Imbalance Market

WMEG - Western Markets Exploratory Group

WSTI - Western States Transmission Initiative

WI - Western Interconnection

APPENDIX F: Glossary

For additional information on commonly used energy terminology, see the following industry glossary links:

- California Air Resources Board Glossary, available at California Energy Commission Energy Glossary, available at https://ww2.arb.ca.gov/glossary
- California Independent System Operator Glossary of Terms and Acronyms, available at: https://www.caiso.com/glossary
- California Public Utilities Commission Glossary of Acronyms and Other Frequently Used Terms, available at https://www.cpuc.ca.gov/glossary/
- Federal Energy Regulatory Commission Glossary, available at https://www.ferc.gov/about/what-ferc/about/glossary
- North American Electric Reliability Corporation Glossary of Terms Used in NERC Reliability Standards, available at: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
- US Energy Information Administration Glossary, available at: https://www.eia.gov/tools/glossary/

Balancing authority

A balancing authority is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time. Balancing authorities in California include BANC, California ISO, Imperial Irrigation District, TID, and LADWP. The California ISO is the largest of about 38 balancing authorities in the WI, handling an estimated 35 percent of the electric load in the West. For more information, see the WECC Overview of System Operations: Balancing Authority and Regulation Overview Web page.

Balancing Authority of Northern California (BANC)

The Balancing Authority of Northern California is a joint powers authority consisting of the SMUD, Modesto Irrigation District, Roseville Electric, Redding Electric Utility, Trinity Public Utility District, and the City of Shasta Lake. The BANC is a partnership between public and government entities and provides an alternative platform to other balancing authorities like the California ISO.

Billion Cubic Feet

Standard unit of measurement for natural gas supply/demand - 1,000,000 MMBtu = 1 Bcf.

British thermal unit

The standard measure of heat energy. Quantity of heat required to raise the temperature of one pound of water 1 degree Fahrenheit at sea level. One Btu is equivalent to 252 calories, 778 foot-pounds, 1055 joules, and 0.293 watt-hours. Note: In the abbreviation, only the B is capitalized.

Climate change

Climate change refers to a change in the state of the climate that can be identified (for example, by using statistical tests) by changes in the mean and/or the variability of its properties and that persists for an extended period, typically decades or longer. Climate change may be due to natural internal processes or external forces such as modulations of the solar cycles, volcanic eruptions, and persistent anthropogenic changes in the composition of the atmosphere or in land use. **Anthropogenic** climate change is defined by the human impact on Earth's climate while **natural** climate change are the natural climate cycles that have been and continue to occur throughout Earth's history. Anthropogenic (human-induced) climate change is directly linked to the amount of fossil fuels burned, aerosol releases, and land alteration from agriculture and deforestation.

Community Choice Aggregation (CCA)

Community Choice Aggregation (CCA) is a program that allows cities, counties, and other qualifying governmental entities available within the service areas of IOUs, to purchase and/or generate electricity for their residents and businesses. The IOU continues to deliver the electricity through its transmission and distribution system and provide meter reading, billing, and maintenance services for CCA customers.

Core Load

A **core load** is that of residential and small business natural gas customers.

Demand response (DR)

Demand response refers to providing wholesale and retail electricity customers with the ability to choose to respond to time-based prices and other incentives by reducing or shifting electricity use ("shift DR"), particularly during peak demand periods, so that changes in customer demand become a viable option for addressing pricing, system operations and reliability, infrastructure planning, operation and deferral, and other issues. It has been used traditionally to shed load in emergencies ("shed DR"). It also has the potential to be used as a low-greenhouse gas, low-cost, price-responsive option to help integrate renewable energy and provide grid-stabilizing services, especially when multiple distributed energy resources are used in combination and opportunities to earn income make the investment worthwhile.

For more information, see the CPUC Demand Response Web page.

Distributed energy resources (DER)

Distributed energy resources are any resource with a first point of interconnection of a utility distribution company or metered subsystem. Distributed energy resources include:

Demand response, which has the potential to be used as a low-greenhouse gas, low-cost, price-responsive option to help integrate renewable energy and provide grid-stabilizing services, especially when multiple distributed energy resources are used in combination and opportunities to earn income make the investment worthwhile.

Distributed renewable energy generation, primarily rooftop PV energy systems.

Vehicle-Grid Integration, or all the ways plug-in electric vehicles can provide services to the grid, including coordinating the timing of vehicle charging with grid conditions.

Energy storage in the electric power sector to capture electricity or heat for use later to help manage fluctuations in supply and demand.

Effective load carrying capability (ELCC)

Effective load carrying capability (ELCC) is the increment of load that could met by the resource while maintaining the same level of reliability. The ELCC of a variable renewable energy resource is based on both the capacity coincident with peak load and the profile and quantity of existing variable renewable energy resources. For a detailed description of ELCC implementation in RESOLVE, see page 87 of the Inputs & Assumptions: CEC SB100 Joint Agency Report.

Extreme event

An extreme event is an event that is rare at a particular place and time of year. Definitions of rare vary, but an extreme weather event would normally be as rare as or rarer than the 10th or 90th percentile of a probability density function estimated from observations. By definition, the characteristics of what is called extreme may vary from place to place in an absolute sense. Examples of extreme events can include drought, extreme heat, and wildfires.

Extreme weather event

An extreme weather event is an event that is rare at a particular place and time of year. Definitions of rare vary, but an extreme weather event would normally be as rare as or rarer than the 10th or 90th percentile of a probability density function estimated from observations. By definition, the characteristics of what is called extreme weather may vary from place to place in an absolute sense. When a pattern of extreme weather persists for some time, such as a season, it may be classed as an extreme climate event, especially if it yields an average or total that is itself extreme (e.g., drought or heavy rainfall over a season).

Federal Energy Regulatory Commission

Regulates natural gas transportation in interstate commerce and construction of gas pipeline, storage, and liquefied natural gas facilities.

Henry Hub

A natural gas pipeline located in Erath, Louisiana, that serves as the official delivery location for futures contracts on the New York Mercantile Exchange.

Integrated Energy Policy Report (IEPR)

SB 1389 (Bowen and Sher, Chapter 568, Statutes of 2002) requires the CEC to prepare a biennial integrated energy report. The report, which is crafted in collaboration with a range of stakeholders, contains an integrated assessment of major energy trends and issues facing California's electricity, natural gas, and transportation fuel sectors. The report provides policy recommendations to conserve resources, protect the environment, ensure reliable, secure, and diverse energy supplies, enhance the state's economy, and protect public health and safety. For more information, see the CEC Integrated Energy Policy Report Web page.

Integrated Resource Planning (IRP)

The CPUC's Integrated Resource Planning (IRP) process is an "umbrella" planning proceeding to consider all of its electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply. The proceeding is also the Commission's primary venue for implementation of the SB 350 (De León, Chapter 547, Statutes of 2015) requirements related to IRP (Public Utilities Code Sections 454.51 and 454.52). The process ensures that load serving entities meet targets that allow the electricity sector to contribute to California's economy-wide greenhouse gas emissions reductions goals. For more information see the CPUC Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP) Web page.

Investor-owned utility (IOU)

Investor-owned utilities (IOUs) provide transmission and distribution services to all electric customers in their service territory. The utilities also provide generation service for "bundled" customers, while "unbundled" customers receive electric generation service from an alternate provider, such as CCAs. California has three large IOUs offering electricity service: Pacific Gas and Electric, Southern California Edison (SCE), and San Diego Gas & Electric.

Liquified Natural Gas

Natural gas that has been cooled to a liquid state, at about -260° Fahrenheit, for shipping and storage.

Load-serving entity (LSE)

A load-serving entity is defined by the California ISO as an entity that has been "granted authority by state or local law, regulation or franchise to serve [their] own load directly through wholesale energy purchases."

Loss of load expectation (LOLE)

The expected number of days per year for which the available generation capacity is insufficient to serve the demand at least once in that day. California has a planning target of expecting no more than one day with an outage every 10 years. Assessments of the LOLE for a system use hundreds or thousands of potential combinations of various system, weather, and resource supply conditions for a single year. The LOLE is then determined by dividing the total number of days with an outage by the total number of simulated years. If the result is not greater than 0.1, the planning target has been met even if all the days with an outage occurred in a single simulated year.

Million British Thermal Unit

A thermal unit of measurement for Natural Gas. See British thermal unit definition.

Million Cubic Feet Per Day (MMcfd)

A unit of measurement used to express the amount of fluid (gas, water etc.) that is consumed, produced or traversed in a pipeline on any given day.

Natural Gas

A hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.

Net qualifying capacity (NQC)

The amount of capacity that can be counted towards meeting RA requirements in the CPUC's RA program. It is a combination of the CPUC's qualifying capacity counting rules and the methodologies for implementing them for each resource type, and the deliverability of power from that resource to the California ISO system.

Noncore Load

Electric generators, industrial customers, commercial, and all other noncore customers.

Once-through cooling (OTC) *Once-through cooling* technologies intake ocean water to cool the steam that is used to spin turbines for electricity generation. The technologies allow the steam to be reused, and the ocean water that was used for cooling becomes warmer and is then discharged back into the ocean. The intake and discharge have negative impacts on marine and estuarine environments. For more information on the phase-out of power plants in California using once-through cooling, see the Statewide Advisory Committee on Cooling Water Intake Structures Web page.

Planning reserve margin (PRM)

Planning reserve margin (PRM) is used in resource planning to estimate the generation capacity needed to maintain reliability given uncertainty in demand and unexpected capacity outages. A typical PRM is 15 percent above the forecasted 1-in-2 weather year peak load, although it can vary by planning area. The CPUC's RA program is increasing the PRM requirement to 16 percent minimum for 2023, and 17 percent minimum for 2024 and beyond.

Publicly owned utility (POU)

Publicly owned utilities (POUs), or Municipal Utilities, are controlled by a citizen-elected governing board and utilizes public financing. These municipal utilities own generation, transmission and distribution assets. Examples include the LADWP and the SMUD. Municipal utilities serve about 27 percent of California's total electricity demand.

Renewables Portfolio Standard (RPS)

The Renewables Portfolio Standard, also referred to as RPS, is a program that sets continuously escalating renewable energy procurement requirements for California's load-serving entities. The generation must be procured from RPS-certified facilities (which include solar, wind, geothermal, biomass, biomethane derived from landfill and/or digester, small hydroelectric, and fuel cells using renewable fuel and/or qualifying hydrogen gas). More information can be found at the CEC Renewables Portfolio Standard web page and the CPUC RPS Web page.

Resource adequacy (RA)

The program that ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves, at or deliverable to locations and at times as may be necessary to ensure local area reliability and system reliability. For more information, see the CPUC Resource Adequacy Web page.

Scenario

A plausible description of how the future may develop based on a coherent and internally consistent set of assumptions about key driving forces (for example, rate of technological change, prices) and relationships. Note that scenarios are neither predictions nor forecasts but are used to provide a view of the implications of developments and actions.

Southern California Gas Company

A utility company and primary provider of natural gas to Los Angeles and Southern California.

Synergi Gas

The long-time industry standard for hydraulic modeling of large, complex distribution and transmission systems.

Time-dependent electricity rates

Time-dependent electricity rates vary depending on the time periods in which the energy is consumed. In a time-of-use rate structure, the most common type of time-dependent rate, higher prices are charged during utility peak-load times. Such rates can provide an incentive for consumers to curb power use during peak times.

Transmission Planning Process (TPP)

The California ISO's annual transmission plan, which serves as the formal roadmap for infrastructure requirements. This process includes stakeholder and public input and uses the best analysis possible (including the CEC's annual demand forecast) to assess short- and long-term transmission infrastructure needs. For more information, see the California ISO Transmission Planning Web page.

Western Electricity Coordinating Counsel (WECC)

The Western Electricity Coordinating Council (WECC) operates as a non-profit corporation ensuring a reliable Bulk Electric System in the geographic area known as the Western Interconnection. WECC has been approved by the Federal Energy Regulatory Commission (FERC) as the Regional Entity for the Western Interconnection. The North American Electric Reliability Corporation (NERC) has delegated authority to create, monitor, and enforce reliability standards to WECC (and other Regional Entities in North America) through a Delegation Agreement.

Western Interconnection (WI)

The physical infrastructure comprising the Bulk Electric System in the geographic area encompassing all or parts of:

- 14 states situated west of, yet including, Montana, South Dakota, Colorado, New Mexico and Texas
- the Canadian provinces of Alberta and British Columbia
- the state of Baja California, Mexico

Generally, transmission lines at or above 100 kV, and the generation and storage resources interconnected to them in the above geographic area make up the Western Interconnection.

Western States Transmission Initiative (WSTI)

A collaboration of western states' regulators and policy leaders focused on developing new approaches to transmission planning and cost allocation in the western interconnection. WSTI proceedings are led by the Gridworks facilitation group for the benefit of members of the Committee on Regional Electric Power Cooperation (CREPC). A primary goal of WSTI is to address energy transition challenges by building a shared understanding of transmission issues among western regulators and state energy policy leaders, surfacing strategies for CREPC to address both opportunities for transmission development across a regional footprint and supporting regulatory and policy foundations. For more information, see the WSTI web page.