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Joint Agency Reliability Planning Assessment

Covering the Requirements of SB 846 (First Quarterly Report for 2026) and SB 1020 (Annual Report)

Gavin Newsom, Governor

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ABSTRACT

The *Joint Agency Reliability Planning Assessment* addresses requirements for electricity reliability reporting in Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) and Senate Bill 1020 (Laird, Chapter 361, Statutes of 2022). The report provides the first quarterly review of 2026, including the demand forecast, supply forecast, and potential high, medium, and low risks to reliability in the California Independent System Operator territory from 2026 to 2036, as required by SB 846. As required by SB 1020, this report also provides a joint reliability progress report that reviews system and local reliability, with a particular focus on summer reliability, identifies challenges and gaps to achieving system and local reliability, and identifies the amount and cause of any delays to achieving compliance with all energy and capacity procurement requirements set by the California Public Utilities Commission.

Keywords: Reliability, Reliability Planning Assessment, SB 846, California ISO, CEC, CPUC, California, electricity, supply and demand, extreme weather, electricity system planning, stack analysis, summer reliability, resource procurement, extreme events

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Introduction

California continues to experience a substantial shift in conditions affecting the electric grid, as it transitions to the state's clean energy future, while confronting the impacts of climate change. Senate Bill 100 (De León, Chapter 312, Statutes of 2018) set 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 this target are resulting in the development of unprecedented quantities of new clean energy resources, primarily utility-scale solar and storage.

From 2020 to 2025, California's electric grid has experienced increasingly unpredictable weather patterns that continue to test system reliability. The state has faced a series of contrasting events, from record breaking heat waves to cooler than average seasons. In 2020, a severe August heat event led to rotating outages lasting between 8 and 90 minutes within the California Independent System Operator (California ISO) balancing area. In 2021, the Bootleg Fire in southern Oregon, which burned from July 6 to August 15, reduced import capability to California by roughly 4,000 megawatts (MW). A year later, extreme heat in early September 2022 drove electricity demand in California to a record peak. In 2024, much of the western United States experienced record-breaking electricity demand, with the Western Interconnection reaching its highest peak on record on July 10, 2024. In contrast, 2025 brought on average, some of the coolest summer temperatures California has experienced in recent years, resulting in lower electricity demand and reduced stress on the grid.

While these weather extremes created operational challenges year to year, broader economic and logistical factors have also influenced the pace of California's energy transition. Global supply chain disruptions compounded these challenges, as delays in obtaining materials for solar panels, battery storage, and other clean energy technologies slowed the state's progress toward expanding renewable energy and firm capacity. Furthermore, supply chain disruptions in network components, such as circuit breakers, dramatically increased project timelines. For example, high voltage circuit breakers, which typically have a lead time of up to 50 weeks, currently have a 200-week lead time because of supply chain issues.

Recognizing these challenges, Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) mandated the California Energy Commission (CEC) and California Public Utilities Commission (CPUC) to develop a quarterly joint agency reliability planning assessment. The assessment is required to include estimates of supply and demand for the next 10 years under different risk scenarios, information on existing and new resources and delays, and a description of barriers to timely deployment of resources. This report is the first quarterly report of 2026. The data analysis completed in this report is based on data that was available through October 1, 2025.

Senate Bill 1020 (Laird, Chapter 361, Statutes of 2022) requires the CEC, CPUC, and California Air Resources Board (CARB) to issue a joint reliability progress report that reviews system and local reliability, with a particular focus on summer reliability; identifies challenges and gaps to achieving system and local reliability; and identifies the amount and cause of any delays to achieving compliance with all energy and capacity procurement requirements set by the CPUC.

The request from SB 1020 is being incorporated into this joint agency assessment to fulfill the requirements of the annual SB 1020 report. The relevant content can be found in Chapter 7.

California's Reliability Situation

Climate change, which is resulting in greater weather variability and natural disasters, continues to create challenges for the expansion of clean energy resources in California, most of which are weather-variable themselves. This interaction has resulted in challenges related to timely and effective planning, securing sufficient scale and diversity of resources needed, and preparing for extreme weather events, including wildfires. State energy entities continue to take steps towards developing new strategies to address potential imbalances of electrical supply and demand. Furthermore, there is greater uncertainty in new resource build due to tariff pressures and the phase-out of federal tax credits.

Demand Forecast

As directed in SB 846, this reliability analysis uses the most recently available *Integrated Energy Policy Report (IEPR)* forecast. For the analysis, staff used the 2024 IEPR Update Planning Forecast from the *2024 IEPR Update*. The planning forecast is the forecast scenario that will be used by the CPUC for its Integrated Resource Planning efforts. In the planning forecast, the annual managed sales for the California ISO region increases from 200,000 gigawatt-hours in 2025 to 293,000 gigawatt-hours in 2034. The 1-in-2 coincident summer peak increases from 46,000 MW in 2025 to 59,000 MW in 2034. The primary drivers for the increase in electricity demand are transportation electrification, building electrification and new data centers.

Supply Forecast

California has separate Integrated Resource Plan processes established by Senate Bill 350 (De León, 2015) for the load serving entities under jurisdiction of CPUC and the largest publicly owned utilities, respectively, to plan for mid- and long-term procurement of energy resources. Meeting increased load from economic and demographic growth and more extreme weather, replacing aging, retiring generation, and achieving greenhouse gas (GHG) emissions reductions translate into an enormous level of procurement in the mid- and long-term. CPUC-jurisdictional load serving entities and publicly owned utilities are procuring new energy resources to meet reliability and GHG emissions reduction targets, but they are facing a variety of barriers, including permitting, financing, and supply chain issues. This report contains information on new supply resources for both CPUC-jurisdictional entities and publicly owned utilities.

The CPUC Integrated Resource Plan process includes a "planning track" and a "procurement track." In the planning track, the CPUC adopts a Preferred System Plan and sets requirements for load serving entities to plan toward it. The Preferred System Plan is an optimal portfolio of resources for meeting state electric sector policy objectives at least cost to ratepayers. In 2019, the CPUC initiated the Integrated Resource Plan "procurement track" to explore possible actions it could take to address potential reliability or other procurement needs. On February 15, 2024, the CPUC adopted the 2023 Preferred System Plan and the 2024-25 Transmission Planning Process portfolios via Decision 24-02-047. Among other things, the decision:

- adopted an aggregated portfolio that reduces statewide yearly GHG emissions from the electric sector to 25 million metric tons by 2035, and
- provided an expected resource development portfolio for the California ISO to be utilized to plan transmission investments for their Transmission Planning Process.

Within the Integrated Resource Plan Proceeding's procurement track, the CPUC has approved three decisions:

- Decision 19-11-016 covering the near term (ending in 2023) reliability;
- Decision 21-06-035 covering the midterm (ending in 2028) reliability; and
- Decision 23-02-040 (supplemental midterm reliability) adding additional procurement to 2026 and 2027

Across these decisions, the CPUC has ordered CPUC-jurisdictional load serving entities to procure a combined amount of 18,800 MW of net qualifying capacity of new electricity resources to come online between 2021 and 2028. These orders will result in more than 25,000 MW of new nameplate capacity, depending on the technology preferences of the procurement entities.

Publicly owned utilities are non-profit community owned utilities that provide electric service within their territories and are governed by locally elected governing boards. While many publicly owned utilities have used integrated resource plans to guide their resource procurement for years, SB 350 established the requirement for the 16 largest publicly owned utilities to adopt integrated resource plans by January 1, 2019, and every five years thereafter, and submit them to the CEC for evaluation of consistency with SB 350 requirements, the state's GHG emissions reduction targets, Renewables Portfolio Standard procurement requirements, and other planning goals. The publicly owned utilities filed the first round of Integrated Resource Plans in 2018-2019, and the CEC found all to be consistent with SB 350 and other requirements. The CEC is currently reviewing the second round of Integrated Resource Plans. So far, all that have been reviewed have been found to be consistent with statutory and guideline requirements. The CEC expects to finish its second review cycle in early 2026.

Tracking Project Development

Since 2020, California energy entities have taken steps to address the potential imbalances between the electrical supply and demand in California, in particular as the electric grid transforms to rely on a high penetration of renewables and low-carbon resources. The Tracking Energy Development Task Force is an inter-agency working group to track new clean energy projects under contract to help overcome barriers to completion. It consists of the CEC, California ISO, CPUC and the Governor's Office of Business and Economic Development.

Large-scale renewable energy projects continue to face the challenges previously reported: unclear or inconsistent permitting processes, supply chain problems that delay project timelines, transmission issues, and impediments to interconnecting to the grid. The Tracking Energy Development Task Force continues to gather information through outreach efforts with developers, governmental entities and other stakeholders that will help to inform our understanding of the issues and build on current progress accelerating energy project deployment.

Reliability Assessments

This report employs both deterministic and probabilistic reliability assessment approaches to evaluate forecasted demand and supply for the 2026–2036 period. While SB 846 mandates analysis at the 5- and 10-year intervals, the CEC and CPUC continue to expand the scope to include annual results for greater detail. This preliminary summer 2026 analysis will be updated in the SB 846 Second Quarterly Report to incorporate timely updates, including hydroelectric conditions and the 2025 IEPR demand forecast. This report also highlights near-term projects expected to come online within the next 1–2 years and provides a comprehensive probabilistic analysis extending to the 10-year horizon.

Near-Term Summer Reliability Assessment

The approach used for the near-term reliability assessment in this report remains consistent with the deterministic Summer Stack Analysis included in prior SB 846 *Joint Agency Reliability Planning Assessment* reports. The analysis evaluates the hourly supply stack against projected demand for peak days in summer, accounting for resource availability and potential stress scenarios.

In summer 2026, California's grid is expected to maintain system reliability under all modeled conditions. Under planning standard conditions, the system shows a surplus of over 4,100 MW, while the 2020 equivalent event and 2022 equivalent event scenarios result in smaller surpluses of over 2,000 MW and 300 MW, respectively. These values represent a modest decline relative to last summer's outlook. The decline is primarily due to lower 2026 net qualifying capacity values, reduced demand response capacity, and delays in several new projects that were originally scheduled to come online in 2025. These resources are expected to be added back into future assessments once their revised operational dates are confirmed.

Wildfire events can also significantly reduce available capacity. For example, transmission impacts from the 2021 Bootleg Fire in Oregon resulted in a 4,000 MW loss of import capability. Such coincident events can compound system risk by significantly reducing supply margins when the grid is already stressed.

The updated analysis highlights the need to continue developing clean energy, address delays from supply chain and permitting challenges, and implement proactive contingency measures to ensure reliability under extreme conditions.

Mid-Term Probabilistic Reliability Assessment (CEC)

The CEC performed a probabilistic assessment of the mid-term state-wide reliability outlook for California from 2031 to 2036, under the supply forecast in the CPUC 2023 Preferred System Plan. The goal of this analysis was to determine if California is meeting the reliability criterion of 1 day in 10-year loss of load expectation, or 0.1 days/year loss of load expectation, under a variety of scenarios related to the retirement of Diablo Canyon Power Plant and import uncertainty. The study finds that the current resource mix and proposed Preferred System Plan additions contain sufficient resources to exceed the 0.1 loss of load expectation reliability criterion and serve load under challenging demand and resource conditions. However, the study did not evaluate all potential risk, and future work is being conducted to evaluate winter reliability risks, the impacts of transmission outages, and drought conditions. Additionally, alternative load scenarios, such as increased or different electric vehicle charging patterns, may drive summer resource adequacy risks not captured here.

System reliability is expected to continue to significantly improve due to (1) significant new resource additions (including utility-scale solar, wind, and batteries, and distributed rooftop solar), (2) new energy efficiency and demand flexibility programs, and (3) the near-term retention of Diablo Canyon Power Plant.

CHAPTER 1: Introduction

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

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 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, which was nearly 2,000 MW higher than the previous record. In late July 2023, parts of the West outside California experienced extreme heat, which drove challenging and fast-moving market dynamics. In 2024, California's mean temperature of 81.7 degrees Fahrenheit in July was ranked the warmest on record compared with a 75.2-degree Fahrenheit average over the previous 130 years. The same year, California was also impacted by the Park Fire in July and Pine Fire in October, which reduced the capacity of key transmission lines. On July 10, 2024, the Western Interconnection[1] reached a new all-time peak demand of 167,988 MW.[2] In contrast, summer 2025 experienced relatively mild conditions compared with recent summers. As a result, the electric system operated under lower stress with California not experiencing any grid emergency events or alerts for 2025.

Addressing Reliability Challenges

Since 2020, California energy entities have taken steps to address the potential imbalances between the electrical supply and demand in California as the electric grid transforms to a high penetration of renewables and low-carbon resources. Even with programmatic changes, resource additions, and Strategic Reliability Reserve (SRR)[3] resources, there exists uncertainty

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1 The Western Interconnection extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.

2 California ISO. 2024. *Summer Market Performance Report: July 2024*. https://www.caiso.com/documents/summer-market-performance-report-july-2024.pdf

3 Developed 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 weather events such as heat and wildfires.

in the supply-and-demand balance in the 5- and 10-year horizons. Despite a boom in new project development, the state needs an even greater buildout of clean energy resources to meet near-term reliability and the long-term clean energy policy goals, embedded in SB 100 and in support of the deep decarbonization strategy outlined in the 2022 Scoping Plan for Achieving Carbon Neutrality that includes meeting the AB 1279 (Muratsuchi, Chapter 337, Statutes of 2022) 85 percent reduction in economy-wide anthropogenic GHG emissions.[4] New strategies are needed to achieve the scale and diversity of resources necessary to accomplish the transition, especially considering continued supply chain disruptions for solar and storage.

Additionally, climate change and extreme heat and wildfire events are affecting the ability of existing models to assess energy reliability into the future due to increasing divergence from historical norms. Planning models and approaches need to continue to be enhanced to account for greater weather variability. The state will continue to benefit from updated planning strategies for bringing on new resources faster and at a larger scale, while engaging more closely with communities on solutions that meet their needs.

California's energy reliability planning requires coordination among the CEC, CPUC, and California ISO. These entities collaborate to enhance forecasting accuracy, streamline resource planning, and assess system reliability for the near-, mid-, and long-term. Since 2020, the following actions have been taken to address these reliability challenges:

- **Increasing Coordination**
  - The Tracking Energy Development (TED) Task Force[5] continues to track the new clean energy projects under development to help overcome barriers to their completion.
  - CEC, CPUC, and California ISO updated their 2010 Memorandum of Understanding in December 2022 to establish and reaffirm linkages among the planning activities at each entity to support the significant number of new resources and transmission needed to meet state goals.[6]
- **Establishing Contingency Resource Programs**
  - The SRR is comprised of three programs that provide funding to secure conventional generation resources, efficiency upgrades at existing natural gas plants, demand response (DR), and distributed generation.
- **Increasing Transparency and Greater Analytics**
  - Regular reports, such as this, provide frequent and ongoing reliability analysis to inform the Legislature and energy policy.

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4 California Air Resources Board. 2022. 2022 Scoping Plan Documents.

https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents

5 Working group between the CEC, CPUC, California ISO, and Governor’s Office

6 2022 Memorandum of Understanding Between The California Public Utilities Commission (CPUC) And The California Energy Commission (CEC) And The California Independent System Operator (ISO) Regarding Transmission and Resource Planning and Implementation. Available via

https://www.energy.ca.gov/sites/default/files/2023-01/MOU_Dec_2022_CPUC_CEC_ISO_signed_ada.pdf

- The CEC revised the California Energy Demand (CED) forecast in the *IEPR* to account for climate change.
- **Increasing Supply Procurement**
  - The CPUC ordered a total of 18,800 MW of net qualifying capacity to be procured by its jurisdictional load-serving entities (LSEs) from 2021-2028.
  - The CPUC is considering ordering an additional 6,000 MW of net quality capacity for the 2029-2032 timeframe.[7]
  - The California ISO conducts the Transmission Planning Process (TPP), which helps assess and prioritize major transmission upgrades to add capacity and relieve grid limitations. The California ISO also continues to improve its interconnection queue through the Interconnection Process Enhancements Initiative with the goal of accelerating the deployment of generation projects.

7 California Public Utilities Commission. Administrative Law Judge's Ruling Seeking Comments on Electricity Portfolios for 2026-2027 Transmission Planning Process and Need for Additional Reliability Procurement. In Section 3: Procurement Need Analysis and Recommendations. Rulemaking 25-06-019. September 30, 2025. Available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M582/K082/582082526.PDF

CHAPTER 2: Summer 2025 Reliability Summary

California entered summer 2025 with a strong reliability outlook supported by continued additions of clean energy resources, including more than 4,500 MW of new capacity added by September. Favorable weather conditions also played a key role, as summer 2025 was significantly cooler than 2024's record breaking heat, with some regions in California experiencing their coolest summer months in decades. Summer electricity demand peaked just above 44,500 MW on August 21, roughly 2,200 MW lower than the forecasted average year. No Flex Alerts or Energy Emergency Alerts (EEAs) were issued, marking the first summer in several years without any alerts, highlighting the impact of moderate weather, new resource additions, and improved planning in maintaining grid reliability.

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 operational playbook, which fosters collaboration and communication with entities such as state agencies, LSEs, and other balancing authorities.

The CPUC's Resource Adequacy (RA) program also contributed to a highly reliable summer in 2025, with all LSEs meeting or exceeding RA requirements based on the CEC's 1-in-2 forecast plus a 17 percent Planning Reserve Margin. Per Decision D.23-06-029,[8] investor-owned utilities (IOUs) also procured additional summer reliability resources beyond RA requirements toward an effective PRM target. Across the June through October showing months, IOUs collectively procured between 791 and 2,107 MW of supply- and demand-side resources, further contributing to system reliability throughout the summer.[9]

Notably, 2025 marked the first year of binding Slice-of-Day (SOD) implementation, representing a fundamental shift in the RA framework away from a single monthly system peak to hourly capacity showings. Under SOD, LSEs demonstrated both resource and storage charging sufficiency across all 24 hours of the CEC's forecasted "worst day" load profile. LSEs successfully made this transition, procuring portfolios to meet all hourly reliability needs, and no system RA deficiencies occurred in any month of 2025.[10]

In addition, the continued development and implementation of the SRR, supplemented existing programs to address reliability risks during extreme events. The SRR includes two demand-side programs administered by the CEC and one supply-side program administered by the Department of Water Resources (DWR). The three programs administered under the SRR include the following:

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8 California Public Utilities Commission. Decision 23-06-029, Decision Adopting Local Capacity Obligations for 2024-2026, Flexible Capacity Obligations for 2024, and Program Refinements. Rulemaking 21-10-002, July 5, 2023. Available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF

9 2025 IOU Excess Resource Reports.

10 2025 Resource Adequacy Month-Ahead Filings.

- **Distributed Electricity Backup Assets Program –** The Distributed Electricity Backup Assets (DEBA) Program[11] incentivizes construction of cleaner, more efficient distributed energy assets that serve as on-call emergency supply or load reduction for the state's electrical grid during extreme events. DEBA provides incentives for efficiency upgrades, maintenance, and capacity additions to existing power generators, as well as new zero- or low-emission technologies, including, but not limited to, fuel cells or energy storage, at existing or new facilities. DEBA was launched in October 2023 when the CEC adopted guidelines with funding to be made available through grants. The first Distributed Energy Backup Assets program grant funding opportunity was released in December 2023 for bulk grid efficiency upgrades and capacity additions at existing bulk grid power plants with a funding allocation of $150 million. In April 2024, the CEC released a Notice of Proposed Awards for nine projects requesting $123 million. If these projects move forward and are approved, they would add about 297 MW of new capacity by 2027 to increase California's grid reliability. Bulk grid projects are anticipated to be completed and come online by summer 2027.
- **Demand Side Grid Support Program** - The Demand Side Grid Support (DSGS) Program[12] was created as a temporary emergency load reduction measure by AB 205 in response to the August 2020 rotating outages. The DSGS Program reduces load by providing incentives to electric customers that provide load reduction and backup generation to support the state's electrical grid during extreme events, reducing the risk of blackouts. The DSGS program was launched in August 2022 with the adoption of initial program guidelines. Those guidelines were later revised in July 2023 to bring on more clean resources with expanded participation eligibility, additional incentive options for clean resources, including storage virtual power plant, and streamlined processes. In May 2024, the CEC further adopted additional revisions to the guidelines for the 2024 summer season, continuing to streamline participation and allowing bi-directional electric vehicle chargers to participate in the storage virtual power plant option. In April 2025, the CEC adopted revisions to program guidelines to further expand participation by clean resources in the 2025 season, including a new emergency load flexibility virtual power plant participation option. The Demand Side Grid Support Program operates from May 1 through October 31 each year and has four incentive options under which customers can participate, as captured in Table 1Table 1.

11 For more information, see the CEC's Distributed Electricity Backup Assets Program webpage, https://www.energy.ca.gov/programs-and-topics/programs/distributed-electricity-backup-assets-program

12 For more information, see CEC's Demand Side Grid Support Program webpage, https://www.energy.ca.gov/programs-and-topics/programs/demand-side-grid-support-program

Table 1: Demand Side Grid Support Incentive Options and Summer 2025 Events

	Option 1: Emergency Dispatch	Option 2: Market Integrated Demand Response	Option 3: Market Aware Storage Virtual Power Plant	Option 4: Emergency Load Flexibility Virtual Power Plant
Eligible Resources	Any load reduction resource	Market-integrated demand response	Storage (batteries + V2X)	Smart thermostats, heat pumps water heaters, electric resistance water heaters, EVSE, stationary batteries, and residential smart electrical panels
Event Trigger	EEA issued by a balancing authority	California ISO energy market bidding & scheduling	California ISO day-ahead energy market locational marginal price (LMP) ≥ $200 per megawatt-hour (MWh), EEA, or a test event	EEA issued by a balancing authority or test events
Summer 2025 Events	None	N/A	Monthly test events (no market LMP or EEA triggered events)	No EEA events; two test events

Source: CEC

- **Electricity Supply Strategic Reliability Reserve Program** – The Electricity Supply Strategic Reliability Reserve Program (ESSRRP)[13] is a statewide program managed by DWR with support from CEC, CPUC, CARB and the California ISO to secure additional energy resources and extend the life of retiring facilities to support grid reliability during extreme events. The ESSRRP was launched in July 2022 by DWR. In 2022, DWR managed 120 MW of temporary and emergency natural gas resources from a separate program operationally aligned to the ESSRRP, 82 MW of emergency backup diesel generators, and 3,349 MW of firm energy import contracts. For summer 2023, DWR closed the Backup Diesel Generation program early in favor of approximately 148 MW of lower-emitting temporary and emergency natural gas resources and 3,391 MW of firm energy import contracts. For 2024, the portfolio of natural gas-powered resources increased up to 3,100 MW, reflecting the inclusion of contracted resources that would have otherwise retired. Aside from necessary testing, these resources are defaulted off until a California-centric balancing authority (BA) issues an EEA or, for long-start resources in the California ISO footprint, ordered by the California ISO to turn on to address extreme events. Approximately 3,100 MW were also available for summer 2025.

Summer 2025 Balancing Authority Recaps

The following sections provide a recap of the reliability performance of multiple balancing authority areas (BAA) in California during summer 2025. These recaps highlight the unique

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13 For more information about the ESSRRP, see DWR's Statewide Energy Office webpage, https://water.ca.gov/Programs/Statewide-Energy-Office

challenges faced and the measures taken by each BAA to maintain grid stability throughout the season.

California Independent System Operator

Overall, reliability conditions across summer 2025 were stable, with the California ISO territory better positioned on resource adequacy (RA) due to the continued addition of new generation and storage resources. Several wildfires were active in summer 2025. The California ISO monitored and managed wildfire risks and potential impacts on grid infrastructure.

Despite periods of heat and wildfire risks during summer 2025, the California ISO did not call any Flex Alerts or EEAs during summer 2025. This further highlights the improved conditions compared to previous years. In 2022, the California ISO issued a record 10 consecutive days of Flex Alerts[14] between August 31 and September 9. Since then, the California ISO has not called any Flex Alerts.

There were several factors that contributed to grid reliability across summer 2025. These include:

- Continued growth of new, clean generation on the California ISO system, notably a proliferation of battery storage resources that charge when solar is abundant and discharge across net peak periods when the sun starts to set.
- The Western Energy Imbalance Market continues to be effective to help balance supply and demand across the wider Western footprint.
- Strong planning and coordination between the California ISO and state agencies, LSEs, and regional partners in advance of and across summer.
- Strategic reliability reserve and demand-side programs were available to provide grid support during extreme weather events.

Balancing Authority of Northern California

The Balancing Authority of Northern California (BANC) is a joint powers agency whose members include the Modesto Irrigation District, City of Redding, City of Roseville, Sacramento Municipal Utility District, City of Shasta Lake, and Trinity Public Utilities District. The BANC footprint also includes the Western Area Power Administration-Sierra Nevada Region and the 500 kilovolt (kV) California-Oregon Transmission Project intertie to the Pacific Northwest. In preparing for summer 2025, BANC performed a reliability analysis, updated its operating procedures, trained its operators, and engaged in joint training exercises with the California ISO and other adjacent BAAs. Similar to analyses conducted by the CEC and California ISO for the California ISO territory, BANC conducted reliability analyses that considered such factors as potential heat events, hydro derates, and potential impacts to imports resulting from wildfires. The BANC assessment determined that BANC had sufficient resources to meet the 1-in-2 and 1-in-10 load for summer 2025 with sufficient operating margins. The assessment also showed sufficient resources for extreme events such as wildfire smoke and California ISO reaching an

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14 Flex Alerts are voluntary calls for consumers to conserve electricity. A Flex alert is typically issued in the summer when extremely hot weather drives up electricity use, making the available power supply scarce. This usually happens in the evening hours when solar generation is going offline, and consumers are returning home and switching on air conditioners, lights, and appliances.

EEA 3. However, BANC would have risks in the event of a West-wide heat event causing a 1-in-20 load and reduced import availability. BANC's 2025 peak load reached 4,316 MW on July 11, 2025, and was 627 MW lower than the all-time peak set in September 2022. BANC members also dealt with a decrease in transfer capability of California–Oregon Intertie (COI) in the range of 475 - 1800 MW due to derate on the 500kV COI transmission lines from scheduled line maintenance by Pacific Gas and Electric (PG&E). This was offset in part by an increase of 52 MW of new solar generation and an increase in hydro power generation due to the above normal water year in 2024/2025. It should also be noted that the Energy Imbalance Market (EIM) performed well during 2025 demonstrating the benefits of peak diversity.

Some of the other efforts to maintain reliability were:

- Increased communications with members and other BAs.
- Appropriate use of EEAs to assist in initiating demand response programs and deploying reserves.
- Increased energy procurement efforts by members as needed.

In preparation for 2026, BANC will continue to conduct detailed summer assessments of anticipated reliability under different scenarios and to evaluate resource adequacy policies in response to heat events. BANC will continue coordination with other BAs, the state, and DOE to identify resources that may be underused, including backup generators.

Contingency Resources

The agencies and the California ISO are continuing to track contingency resources, which are resources outside of those considered in the stack analysis and provide support during an extreme event. Contingency resources, identified in Table 2, were expected to provide between 4,100 MW and 4,600 MW during extreme events. The values for CPUC programs shown in Table 2 are sourced from the three investor-owned utilities' (IOUs') Excess Resources Reports, which are submitted monthly to the CPUC during the peak season (May - October) per Decision D.21-12-015 of Emergency Reliability Rulemaking R.20-11-003.[15] This report uses the data from the IOUs' October filings.[16]

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15 The Emergency Reliability Final Decision D.21-12-015 and Rulemaking R.20-11-003 are available on the Summer Reliability website here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/summer-2021-reliability.

16 PG&E: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/pgeexcess-resource-reporting-d211201509032024.xlsx,

SCE: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/sceexcess-resource-reporting-d211201509302024.xlsx,

SDG&E: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/sdgeexcess-resource-reporting-d21120150912024.xlsx

Table 2: Recap of Contingency Resources for Summer 2025

TYPE	CONTINGENCY RESOURCE	AVAILABLE MW JULY	AVAILABLE MW AUGUST	AVAILABLE MW SEPTEMBER
SRR, SPAP	DWR[13] Electricity Supply Strategic Reliability Reserve Program and State Power Augmentation Program (SPAP)	3,079	3,079	3,079
SRR	Demand Side Grid Support	639	657	678
SRR	Distributed Electricity Backup Assets (under development)	0	0	0
CPUC	Ratepayer Programs (Emergency Load Reduction Program, Smart Thermostats, etc.)	128	123	124
CPUC	Imports Beyond Stack	0	0	0
CPUC	Capacity at Co-gen or Gas Units Above RA	599	599	499
NON-PROGRAM	Balancing Authority Emergency Transfers	300	300	300
NON-PROGRAM	Thermal Resources Beyond Limits: Gen Limits Needing 202c	25	25	25
	Total	4,743	4,783	4,737

Source: CEC staff with California ISO, Department of Water Resources, and CPUC data.

Conclusion

In summer 2025, the joint state agencies and BAAs successfully prepared the grid to manage high demand, extreme heat, and wildfire risks. During August 2025, LADWP operated through multiple heatwaves without rolling blackouts and relied on conservation messaging while only experiencing localized distribution outages rather than system-level outages[17]. IID faced tight conditions in early August[18] and issued conservation alerts to avoid any heat-driven load shedding. Continued operation of the SRR provided critical backup resources, while favorable weather conditions and the ongoing growth of clean energy and battery storage supported overall grid stability. Collaboration among the BAAs played a key role in minimizing emergency measures, such as Flex Alerts, and ensuring reliability.

17 City News Service. 2025. "Southern California power grid holding firm as heat wave grips region." Los Angeles Daily News. https://www.dailynews.com/2025/08/21/thousands-without-power-in-la-county-and-city-as-heat-wave-grinds-on/

18 NBC Palm Springs. 2025. "IID Issues Conserve Alter to Prevent Power Outages This Week." https://www.nbcpalmsprings.com/2025/08/06/iid-issues-conserve-alert-to-prevent-power-outages-this-week

Looking ahead to 2026 and beyond, maintaining California's grid reliability will depend on continued investment in clean energy, resource planning, and coordination among balancing authorities, agencies, and reliability partners. As climate and demand pressures intensify, ongoing refinement of contingency resources and emergency preparedness programs will be essential to ensuring the grid can respond effectively to extreme weather, wildfires, and other unexpected events. These combined efforts will help California maintain system stability while advancing its transition toward a clean, reliable, and resilient energy future.

CHAPTER 3: California Energy Security Plan

The 2021 Infrastructure Investment and Jobs Act[19] requires State Energy Security Plans to be reorganized to:

- Address all energy sources
- Provide an updated state energy profile
- Provide an updated energy sector risk assessment and energy sector hazard assessment
- Address multi-state, tribal, and regional coordination.

States are required each year through October 2025 to submit to the DOE an energy security plan for review or a Governor's letter affirming that the existing plan meets all Section 40108 provisions.

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. Recent California Energy Security Plan submission activities include the following:

- In September of 2023, a draft updated California Energy Security Plan was submitted to the DOE Office of Cybersecurity, Energy Security, and Emergency Response (CESER) 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.
- On September 24, 2024, the CEC resubmitted the California Energy Security Plan satisfying the submission requirements.
- On September 29, 2025, the CEC submitted a revised California Energy Security Plan satisfying the submission requirements. The 2025 State Energy Security Plan review and update activities included the following:
    - Updated the California Energy Profile and key data sections with information collected through the first quarter of 2025.
    - Aligned the document with statewide planning documents by incorporating updates from California's most recent emergency, hazard mitigation, and cybersecurity plans.
    - Enhanced the resilience and reliability content by adding details on recent programs, initiatives, and activities.

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19 2021. H.R.3684 - *Infrastructure Investment and Jobs Act*.
https://www.congress.gov/bill/117th-congress/house-bill/3684.

- Updated the coordination activities to reflect current regional, federal, and tribal engagement efforts.

The CEC team continues to engage the CESER team and California agencies in support of continued improvement on issues that pertain to energy security and reliability.

CHAPTER 4: Demand Forecast

Demand Forecast Scenarios

As directed in SB 846, this reliability analysis uses the most recently available IEPR Forecast, which is the *2024 IEPR Update*, adopted in January of 2025. The *2024 IEPR Update* includes a baseline forecast, a planning forecast, and a local reliability forecast. This analysis uses the planning forecast, which considers the impacts of "additional achievable" scenarios for energy efficiency, fuel substitution and transportation electrification beyond the baseline forecast, and is typically used for planning resource procurement and transmission.

For more information on the 2024 IEPR Update Forecast, including inputs and assumptions, methodology, and results, see the *2024 IEPR Update*[20] and the December 12, 2024, IEPR workshop materials.[21]

2024 IEPR Update Planning Forecast Results

In the planning forecast, the annual statewide sales increases from 245,000 gigawatt hours (GWh) in 2025 to 354,000 GWh in 2034. Sales for the California ISO region[22] increase from 200,000 GWh in 2025 to 293,000 GWh in 2034. The 1-in-2 coincident summer peak for the California ISO region increases from 46,000 MW in 2025 to 59,000 MW in 2034. The primary drivers for the increase in electricity demand are transportation electrification, building electrification and new data centers, although there are uncertainties in the magnitude and timing for each of these areas of load growth.

For more information, refer to Chapter 4 of the *Joint Agency Reliability Planning Assessment: Covering the Requirements of SB 846 (Combined First and Second Quarterly Report for 2025) and SB 1020 Annual Report,*[23] which contains a more detailed analysis of the *2024 IEPR Update* impacts on reliability.

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20 Bailey, Stephanie, Mathew Cooper, Quentin Gee, Heidi Javanbakht, Jake McDermott, Danielle Mullany. 2024. *2024 Integrated Energy Policy Report Update*. California Energy Commission. Publication Number: CEC-100-2024-001.
https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report

21 IEPR Workshop presentations and event recordings are available at
https://www.energy.ca.gov/event/workshop/2024-12/iepr-commissioner-workshop-draft-forecast-results.

22 The California Independent System Operator region primarily consists of the Transmission Access Charge (TAC) areas for PG&E, SCE, and SDG&E.

23 Yee Yang, Chie Hong, and Brendan Burns (CPUC). May 2025. *Joint Agency Reliability Planning Assessment: Covering the Requirements of SB 846 (Combined First and Second Quarterly Report for 2025) and SB 1020 (Annual Report)*. California Energy Commission. Publication Number: CEC-200-2025-004.
https://www.energy.ca.gov/publications/2025/joint-agency-reliability-planning-assessment-covering-requirements-sb-846

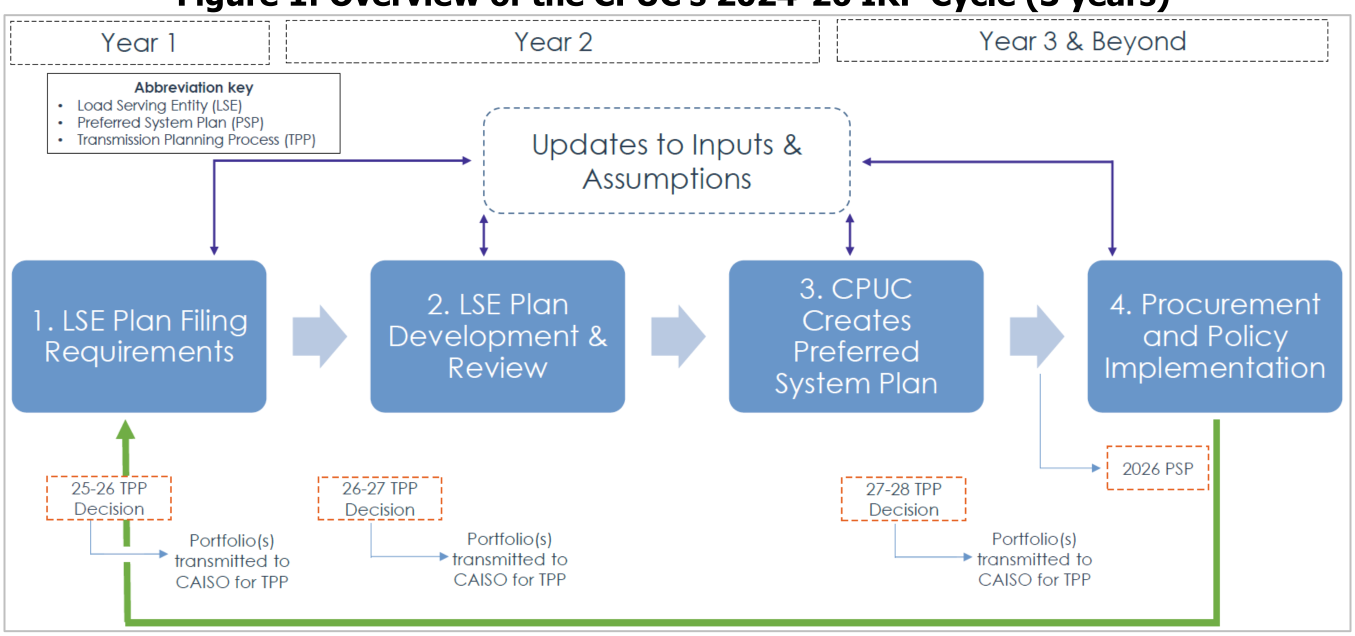
CHAPTER 5: Supply Forecast

Background

California has an Integrated Resource Planning (IRP) process that was established by SB 350 to plan for mid- and long-term procurement of energy resources. The process differs for CPUC-jurisdictional entities and non-CPUC-jurisdictional entities. The IRP process for CPUC-jurisdictional LSEs succeeded the CPUC's longstanding Long-Term Procurement Planning process, established by Assembly Bill 57 (Wright, Chapter 835, Statutes of 2001). The CPUC IRP process aims to reduce the cost of achieving GHG emissions reductions and other policy goals by looking across LSE boundaries and resource types to identify solutions to reliability, cost, or other concerns that might not otherwise be found. Separately from the CPUC IRP process, the 16 largest publicly owned utilities submit IRPs to the CEC every five years and are reviewed by CEC staff for consistency with SB 350 requirements.

The CPUC's IRP is a multi-step process, the major steps of which are laid out in Figure 1 below. The first half of an IRP cycle typically builds on the findings of the previous cycle. It is designed to provide analysis and guidance for those who provide power to the grid (LSEs) to plan for meeting their GHG emissions, reliability, and cost objectives. The second half of the IRP cycle is designed to consider the portfolios and actions that each LSE proposes for meeting these objectives. At this stage, the CPUC reviews each LSE plan, aggregates each individual IRP, and develops a Preferred System Plan (PSP) portfolio. The development and adoption of a PSP represents the final step of an IRP cycle.

Figure 1: Overview of the CPUC's 2024-26 IRP Cycle (3 years)



Source: CPUC Staff

CPUC IRP Planning Track

The CPUC is currently running the 2024-26 IRP Cycle. At this point in the planning cycle, it manages two related workstreams. The first effort is to support the development of a PSP with targeted adoption in 2027. LSEs are developing their individual integrated resource plans (IRPs) based on filing requirements materials that CPUC staff produced for LSEs to meet statutory requirements for reliability and emissions reduction at lowest cost. As part of developing the filing requirements for LSEs, the CPUC conducted a stakeholder process in 2025 to update its modeling inputs and assumptions that underlie IRP modeling. Second, the CPUC is currently developing and vetting portfolios for study in California ISO's 2026-27 TPP, described in the following section.

Annual TPP Cycle

Every year, CPUC staff develops a recommended base case portfolio and can also develop a sensitivity portfolio for the California ISO to use in its annual TPP.[24] The California ISO evaluates a reliability and/or policy-driven base case portfolio to see if transmission upgrades are needed. Under the California ISO tariff adopted by the Federal Energy Regulatory Commission, if the results of the base case analysis show the need for additional transmission development, California ISO brings the transmission projects to its board for approval in the spring of the second year of the TPP. If approved by the California ISO Board, the project would receive cost recovery through the transmission access charge (TAC). Along with the base case analysis that leads directly to transmission project approval, the California ISO can analyze one or more "sensitivity" portfolios. Policy-driven sensitivity portfolio analyses are designed either to support a "least regrets" approach that provides a reasonable range of future scenarios that can be linked to the base case or to gather additional transmission information to support future portfolios' development. Identified transmission solutions in policy-driven sensitivities do not directly go to the California ISO Board for approval, but they can help inform base case solutions.

In February 2025, the CPUC adopted the 2025-26 TPP portfolio in Decision (D.) 25-02-026. This Decision included both a base case and a sensitivity portfolio that the California ISO is currently analyzing. The base case portfolio was based on a scenario that achieves a 25 million metric ton (MMT) GHG emissions target in 2035, including 4.5 gigawatts (GW) of offshore wind based on the amounts LSEs submitted in their last IRP submissions in November 2022. Offshore wind is not optimally selected in IRP's last-cost modeling. The 2025-26 base case portfolio corresponds to the low end of the 2030 target range for GHG emissions set by CARB when it adopted the most recent Scoping Plan update.[25] The sensitivity portfolio was a "Long Lead-Time (LLT) Resource" scenario, based on the upper bounds of the need determination analysis of LLT resource volumes. Significant amounts of LLTs are often identified in the portfolios that CPUC's IRP process develops and adopts. There are multiple pathways for these

24 During years that the CPUC adopts a PSP (once per IRP cycle, or every two to three years), its adopted TPP base case portfolio is identical to the PSP portfolio. In the other years, the TPP portfolios use an updated set of model assumptions compared to the most recently adopted PSP.

25 California Air Resources Board. December 15, 2022. *2022 Climate Change Scoping Plan for Achieving Carbon Neutrality*. https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2022/res22-21.pdf.

resource types to be procured, though. DWR, as a Central Procurement Entity, could potentially procure these, as reflected in the Commission's adopted decision (D.24-08-064). Any solicitations done by DWR through this mechanism are subject to CPUC approval. The need determination in D.24-08-064 included geothermal, long-duration energy storage (LDES) with specified durations, and offshore wind resources.

On September 30, 2025, the CPUC issued an Administrative Law Judge's Ruling Seeking Comments on Electricity Resource Portfolios for 2026-2027 TPP.[26] The Administrative Law Judge's Ruling and CPUC staff's supplemental analysis[27] considered two TPP portfolio classifications. This included a proposed 2025-2026 TPP Base Case and CPUC staff's recommended sensitivity portfolio of a "Limited Wind" scenario. This proposed sensitivity reflects the recent lack of wind development in California, the recent increased difficulty of permitting wind in California, and the recent changes in Federal policy toward wind projects. The Ruling also describes an alternative of not recommending a sensitivity portfolio for the California ISO to study in the 2026-2027 TPP cycle and includes two other potential sensitivity portfolios that are not recommended by CPUC staff. CPUC staff reviewed party comments on the 2026-2027 TPP Ruling and are working toward adoption of a 2026-2027 TPP Decision in the first quarter of 2026.

CPUC IRP Procurement Track

New Megawatts Online

Throughout the California ISO balancing authority, 29,001 MW of new nameplate capacity have come online from January 2020 to October 31, 2025. As shown in Figure 2, California continues to experience rapid growth in renewable resources, particularly solar photovoltaics and energy storage. In 2024 alone, roughly 7,000 MW of new nameplate capacity were added to the electric grid. This growth took place despite challenges outlined in previous reports including permitting, construction, and the interconnection processes. Increased transmission development, approved by the California ISO, should increase the amount of both in-state and out-of-state project development in the coming years.

Figure 2 below shows cumulative new capacity additions within the California ISO service territory from January 2020 to October 2025 as well as expected new resource additions based on current LSE contracts through 2028.

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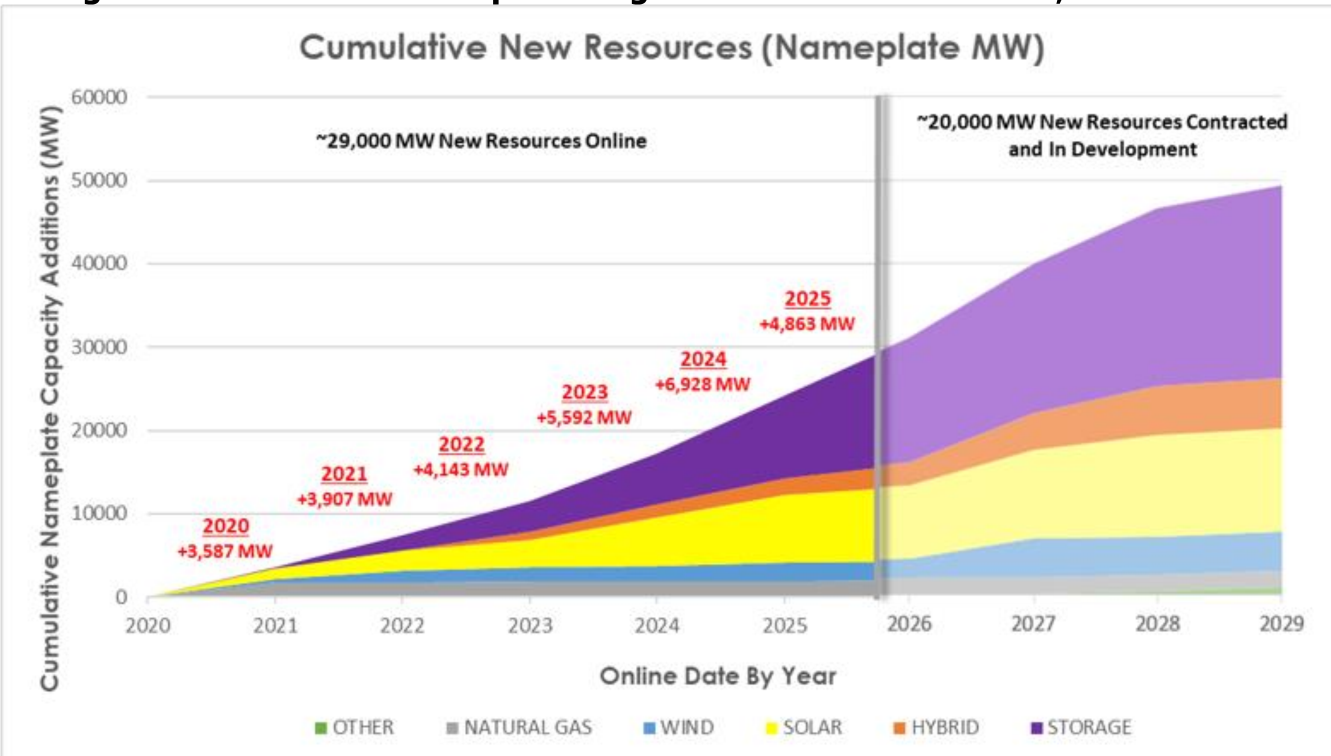
26 California Public Utilities Commission. September 12, 2024. *Administrative Law Judge's Ruling Seeking Comments on Electricity Resource Portfolios for 2025-2026 Transmission Planning Process*. Rulemaking 20-05-003.
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M539/K999/539999211.PDF.

27 California Public Utilities Commission. September 12, 2024. *2025-2026 TPP RESOLVE Modeling Results [presentation].* Rulemaking 20-05-003.
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2025-2026-tpp/25-26-proposed-tpp-resolve-analysis-slide-deck_final_ver2.pdf.

Figure 2: Cumulative Nameplate Megawatts of New Resources, 2020 to 2028



Source: CPUC, October 2025

Overview of IRP Procurement Orders (D.19-11-016, D.21-06-035, and D.23-02-040)

Through three decisions in the IRP proceeding, the CPUC has ordered 18,800 MW Net Qualifying Capacity (NQC)[28] of procurement from CPUC-jurisdictional LSEs from 2021-2028.[29] The 3 decisions ordering procurement, D.19-11-016, D.21-06-035 Mid Term Reliability (MTR), and D.23-02-040 (Supplemental MTR), are summarized in Table 3Table 3.

Table 3: IRP Procurement Orders (MW NQC)

CPUC Orders	Total	2021	2022	2023	2024	2025	2026	2027	2028
D.19-11-016 Applies to 25 LSEs since 18/43 LSEs opted out	3,300	1,650	825	825	n/a	n/a	n/a	n/a	n/a

28 A measure of how much capacity system planners can rely upon the resources to provide to the grid during typical September conditions when peak loads are high and renewable generation is low

29 The IRP procurement order decisions, D.19-11-016, D.21-06-035, and D.23-02-040, are available on the IRP Procurement track website here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track.

CPUC Orders	Total	2021	2022	2023	2024	2025	2026	2027	2028
D.21-06-035[30] (MTR) Applies to all CPUC-jurisdictional LSEs. No opt-outs allowed	11,500	n/a	n/a	2,000	6,000	1,500	n/a	n/a	2,000
D.23-02-040 (Supplemental MTR) Applies to all CPUC-jurisdictional LSEs. No opt-outs allowed	4,000	n/a	n/a	n/a	n/a	n/a	2,000	2,000	n/a
Cumulative Procurement Ordered	18,800	1,650	2,475	5,300	11,300	12,800	14,800	16,800	18,800

Source: CPUC Decision 19-11-016, Decision 21-06-035, Decision 23-02-040, Decision 24-02-047

Compliance with CPUC 2019 Procurement Order (D.19.11-016) Near Term Reliability and (D.21-06-035) Mid Term Reliability

In July 2025, CPUC staff released the Summary of Compliance with IRP Order D.19-11-016 and MTR (D.21-06-035) Procurement after analyzing the LSEs' December 2024 compliance filings.[31] All of the data released in the CPUC staff analysis shows claimed procurement by LSEs towards IRP procurement orders. CPUC staff review of the December 2024 filing

30 (1) D.21-06-035 required 2,500 of the 9,000 MW required between 2023-2025 be zero-emitting generation, generation paired with storage, or demand response resources for Diablo Canyon Replacement Firm Zero Emitting (DCR Firm ZE). (2) D.21-06-035 required 2,000 MW of Long-Lead Time Procurement by 2026, with an option to extend to 2028: 1,000 MW of long-duration storage and 1,000 MW of firm zero-emitting. D.23-02-040 automatically extends the procurement obligation to 2028. D.24-02-047 provides additional options to extend those deadlines until 2031 on a project-by-project basis.

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

indicates LSEs subject to MTR and Supplemental MTR procurement obligations have largely met their obligations for MTR Tranches 1 and 2 (corresponding to Years 2023 and 2024).

High levels of compliance were achieved despite interconnection challenges and a constrained generation market, due to both the large number of new resources that have come online in the past few years and the regulatory flexibility for LSEs to use bridge resources (largely imports) in the event of project delay.[32]

For 2023, LSEs procured and brought online 99 percent of their cumulative 2,000 MW NQC obligation, and for 2024, they procured and brought online about 93 percent of their cumulative 8,000 MW NQC obligation. Much of the contracted capacity submitted for MTR and Supplemental MTR compliance was for battery storage, solar, or hybrid resources. More comprehensive information about compliance with IRP procurement orders can be found in the CPUC Summary of Compliance with IRP Order D.19-11-016 and MTR D.21-06-035 Procurement.[33]

Estimates of Resources Under Contract to CPUC-Jurisdictional LSEs

This section updates the estimated expected new capacity currently under contract to CPUC-jurisdictional LSEs through 2028. Table 4 through Table 6 include resources being developed for compliance with IRP procurement orders as well as procurement for LSE compliance with other regulatory compliance obligations, including RA, Renewables Portfolio Standard (RPS), and procurement the CPUC approved in the Emergency Reliability proceeding. All totals provided below represent the cumulative LSE-reported expected September NQC under contract to CPUC-jurisdictional LSEs.[34]

LSE procurement activity is still ongoing and evolves regularly to meet LSE procurement portfolio needs. Shown in Table 4 through Table 6 are estimated resources by TAC area, LSE type, and technology type. The tables do not include all known resources in development in California, nor in all of the California ISO's footprint, and represent only resources known to be under contract to CPUC-jurisdictional LSEs between 2025 and 2028, as of October 2025. These

32 D.21-06-035 (MTR) allowed the use of a short-term, "bridge" contract to be used to ensure compliance in the event of a specific delayed resource. D.23-02-040 stated that bridge contracts cannot be longer than three years. D.24-09-006 allowed bridge contracts that meet certain requirements to count towards the Diablo Canyon Replacement category of the MTR Decision.

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

34 Developers often aim to bring projects online in advance of contractual obligations. The data underlying the expected projects can be challenging to track. A new resource can have several expected on-line date changes, multiple off-takers, several on-line dates for different tranches of a project, multiple technologies in various configurations, changes to project sizing, changes to project naming, and multiple California ISO resource identification numbers once they come online.

totals are subject to change as the CPUC receives new data from LSEs, conducts field calls with developers and IOUs' interconnection departments, and continues to evaluate the data. The tables below show new supply resources that are expected to come online each quarter from October 2025 until 2028.[35] In Table 4 through Table 6, the new supply resources are measured in NQC. Figure 2 in the "New Megawatts Online" section shows roughly 20,000 MW of new nameplate capacity will come online in the next few years, and the tables below show those same resources, using NQC accounting, as roughly 14,000 MW of NQC.

Procurement by TAC Area

Table 4: Estimated New September NQC (MW) by TAC Area 2025 through 2028

TAC Area	2025 Q3-Q4	2026 Q1-Q2	2026 Q3-Q4	2027 Q1-Q2	2027 Q3-Q4	2028 Q1-Q2	2028 Q3-Q4
East Central	656	1,619	2,495	4,239	4,620	5,969	5,990
North	337	791	1,057	2,229	2,488	2,595	2,771
South	11	525	598	721	795	795	795
Other	570	1,444	2,428	2,871	4,111	4,590	4,590
Total	**1,573**	**4,378**	**6,578**	**10,060**	**12,014**	**13,949**	**14,145**

Source: CPUC Staff Aggregation of October 2025 LSEs' Procurement Status Reports

Procurement by LSE Type

Table 5: Estimated New September NQC (MW) by LSE Type 2025 through 2028

LSE Type	2025 Q3-Q4	2026 Q1-Q2	2026 Q3-Q4	2027 Q1-Q2	2027 Q3-Q4	2028 Q1-Q2	2028 Q3-Q4
IOU[36]	1,254	2,279	3,499	4,503	6,103	7,064	7,064
Non-IOU	319	2,099	3,079	5,557	5,911	6,885	7,081
Total	**1,573**	**4,378**	**6,578**	**10,060**	**12,014**	**13,949**	**14,145**

Source: CPUC Staff Aggregation of October 2025 LSEs' Procurement Status Reports

Procurement by Resource Type

Table 6: Estimated New September NQC (MW) by Resource Type 2025 through 2028

35 Each figure in Tables 1-6 is rounded up to the nearest MW; consequently, the values in the "Total" rows may diverge slightly from the sum of the subtotal values directly above each of them, respectively.

36 Investor-owned utility.

Resource Type	2025 Q3-Q4	2026 Q1-Q2	2026 Q3-Q4	2027 Q1-Q2	2027 Q3-Q4	2028 Q1-Q2	2028 Q3-Q4
Solar	81	109	555	709	1,477	1,477	1,477
Battery	1,347	3,100	4,003	6,323	7,334	8,756	8,870
Paired / Hybrid	125	893	1,242	2,120	2,255	2,288	2,338
Wind	16	252	658	658	658	662	662
Geo-thermal	-	20	110	241	282	756	788
Biomass / Biogas	4	4	10	10	10	10	10
Total	**1,573**	**4,378**	**6,578**	**10,060**	**12,014**	**13,949**	**14,145**

Source: CPUC Staff Aggregation of October 2025 LSEs' Procurement Status Reports

Proposed New Procurement Order

On September 30, 2025, a CPUC Administrative Law Judge issued a ruling[37] that included a proposal to order additional procurement from LSEs. The proposed order would be a collective 1,500 MW in each year from 2029 to 2032, for a total of 6,000 MW of new incremental capacity for the California ISO area. The ruling included the proposal after a CPUC staff analysis, using the 2024 IEPR demand forecast, found that the volumes of expected resources available from 2029 to 2032 as modeled would be insufficient to meet the reliability standard of 0.1 loss of load expectation (LOLE). The ruling proposed that LSEs could count "excess" procurement (beyond the minimum required to comply with the previous procurement orders) toward their assigned obligations and that LSEs' respective procurement would be accounted for in a potential successor program, described in the next section.

37 California Public Utilities Commission. Administrative Law Judge's Ruling Seeking Comments on Electricity Portfolios for 2026-2027 Transmission Planning Process and Need for Additional Reliability Procurement. Rulemaking 25-06-019. September 30, 2025. Available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M582/K082/582082526.PDF

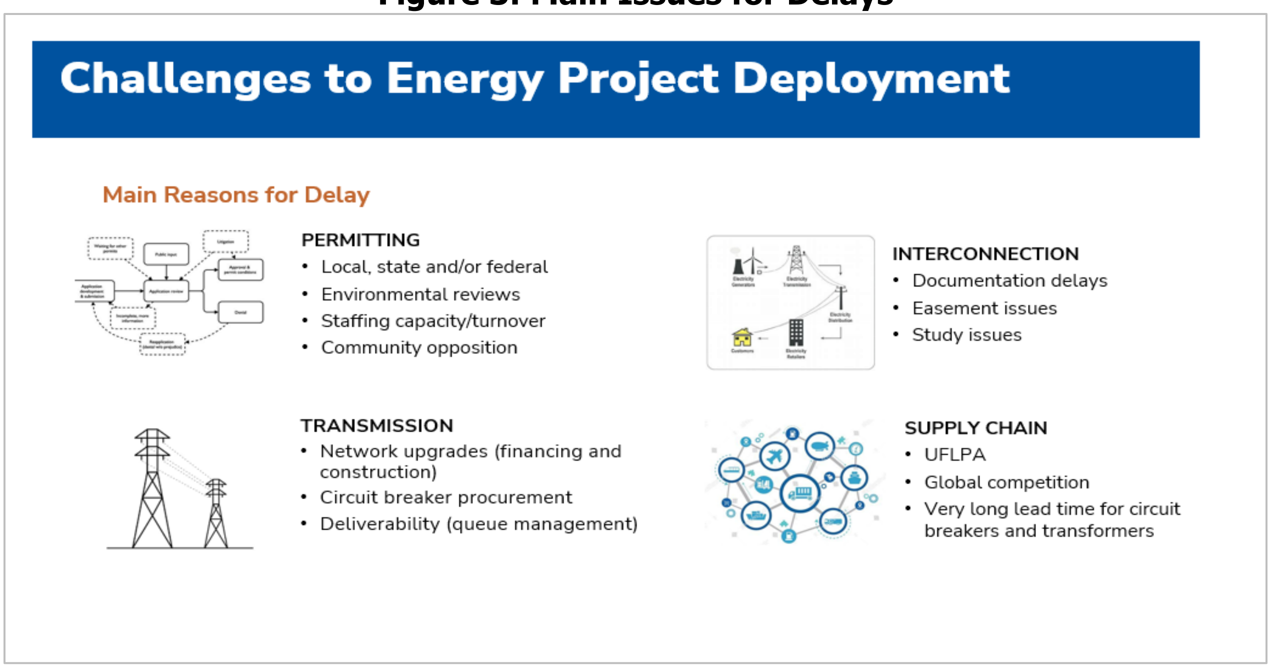
CHAPTER 6: Tracking Project Development

Since 2020, California energy entities have taken steps to address the potential imbalances between the electrical supply and demand in California, in particular as the electric grid transforms to rely on a high penetration of renewables and low-carbon resources. The CEC, CPUC, California ISO, and Governor's Office substantially increased coordination and developed the 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 their completion. The priority focus for the TED Task Force is near-term projects, defined as those that can come online in the next one to three years.

Tracking Energy Development Task Force

The TED Task Force continues to gather information through outreach efforts with developers, governmental entities and other stakeholders that will help to inform the Task Force's understanding of the issues and build on the current work progress to accelerate energy project deployment. The TED Task Force has found that clean energy project deployments face many of the same challenges as previously reported. These challenges include supply chain shortages for critical equipment, interconnection delays, transmission capacity, and permitting and siting approval delays. Figure 3[38] lists the most cited issues/problems facing developers.

Figure 3: Main Issues for Delays



38 "UFLPA" refers to the Uyghur Forced Labor Prevention Act.

Source: GO-Biz

A large-scale energy project takes years from start of development to finally reach commercial operation and may encounter more than one issue that could delay it reaching its commercial operation date (COD).[39] Additionally, some categories of issues are interconnected. For example, the network upgrade needed for transmission is delayed by procurement of critical equipment such as a circuit breaker.

As of October 21, 2025, the TED Task Force is tracking 194 projects that are expected to come online over the next several years. Of the total projects:

- 39 projects are currently on track to meet COD;
- 59 projects have encountered issues that *may* delay reaching COD; and
- 96 projects have faced issues that resulted in an extension of the COD, with the average delay time of about 20 months from the original COD.

Elimination of Federal Tax Credits for Clean Energy Projects

A significant issue impacting deployment of clean energy projects is the recent federal actions taken to eliminate the federal tax credits for clean energy projects. The House of Representatives Bill 1 (HR 1), together with new measures implemented by the Department of Interior, will end the long-term incentives created under the Inflation Reduction Act of 2022 for clean energy projects, hamper deployment of current projects in the state and negatively impact California's progress towards achieving carbon-fee electricity by 2045.

In response to HR 1, the Governor issued an Executive Order N-33-25[40] to help projects capture the expiring federal tax credits. Specifically, the Executive Order does the following:

- Designates the Energy Working Group of the Governor's Infrastructure Strike Team to track projects eligible for tax credits and state agencies' actions to accelerate clean energy project development.
- Directs relevant state agencies to prioritize actions within their purview that support projects beginning construction before July 4, 2026, or coming online by December 31, 2027, to capture the expiring federal tax credits.
- Directs state energy agencies to assess actions both to capture expiring clean energy tax credits and to further expedite clean energy deployment, and to submit recommendations to the Governor for consideration.

Clean Energy Projects Deployed

As of October 1, 2025, 77 projects totaling 4,130 MW came online this year.

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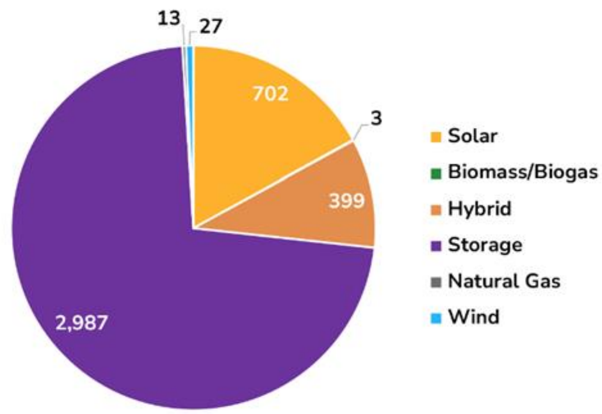
39 A project's commercial operation date is when a project is complete and commercially operating on the market. Note that CODs are estimated by developers based on a variety of factors that could affect when the project will become operational.

40 Executive Order N-33-25 available at: https://www.gov.ca.gov/wp-content/uploads/2025/08/Clean-Energy-EO_8.29.25_Formatted.FINAL_ATTESTED.pdf

Figure 4 shows the new MW online by resource type. And Figure 5 lists the top 10 counties by MW added to the grid, as well as a map showing location of deployed projects.

Figure 4: 2025 Online MW by Resource Type



2025 | Total Online Megawatts (MWs)

Online MWs	4,130
Online Projects	77

Source: GO-Biz, as of October 1, 2025

Figure 5: 2025 Top 10 Counties by MW Deployed, January-October

County	Online MWs	Online Projects
Kern	1,002	21
San Diego	557	4
Imperial	300	2
Fresno	297	4
Alameda	275	1
Kings	249	9
Riverside	192	6
San Joaquin	145	2
San Bernardino	121	6
San Luis Obispo	100	1

Source: GO-Biz

New resources span a range of technology types. Table 7 summarizes MW and projects added in 2025 by technology. It summarizes the same data points for cumulative additions from 2020 to 2025.

Table 7: Cumulative New Resource Additions, in 2025 and for January 2020 through September 30, 2025

Technology Type	Nameplate Capacity (MW) 2025	Estimated Sept. Net Qualifying Capacity (NQC) MW 2025	Number of Projects 2025	Nameplate Capacity (MW) 2020-2025	Estimated Sept. Net Qualifying Capacity (NQC) MW 2020-2025	Number of Projects 2020-2025
STORAGE	2,922	1,858	35	12,715	11,417	172
SOLAR	552	82	27	8,521	2,385	148
HYBRID (STORAGE/ SOLAR)	395	316	5	2,168	1,473	29
WIND	27	6	1	1,128	249	23
GEOTHERMAL				41	31	1
BIOGAS, BIOGAS, HYDRO	3		1	42	0.1	12
Subtotal Total New SB 100 Resources, California ISO	**3,899**	**2,261**	**69**	**24,615**	**15,555**	**385**
NATURAL GAS, incl. Alamitos & Huntington Beach	13	1	4	1,551	1,487	19
Total New Resources, California ISO	**3,911**	**2,262**	**73**	**26,166**	**17,042**	**404**
New Imports, Pseudo-Tie or	150	58	1	2,033	1,119	16

Dynamically Scheduled						
Total New Resources, including Imports	**4,061**	**2,320**	**74**	**28,199**	**18,162**	**420**

Source: California ISO Master Control Area Generating Capability Lists and CPUC NQC Lists, January 1, 2020 to September 30, 2025

CHAPTER 7: Near-Term Reliability Assessment and SB 1020

CEC staff conducted the Near-Term Reliability Assessment used for this chapter, which is consistent with the same assessment used in previous SB 846 *Joint Agency Reliability Planning Assessment* reports.[41] Chapter 8 provides a probabilistic analysis for the mid- and long-term horizons. The analysis in this chapter compares an hourly evaluation of anticipated supply against the projected hourly demand for the peak day of each month, July through September. The comparison stacks the resources expected to be available in each hour and compares the total against the projected demand plus an 18 percent reserve margin (referred to as the current RA planning standard, or planning standard), equivalent events to 2020 and 2022 peaks, and those situations under high fire risk. This assessment identifies the max hourly shortfall by year for each scenario. The stack analysis is used primarily for understanding the extent of contingency resources that might be needed to support grid reliability in extreme events.

Stack Analysis

The following is a summary of the key input assumptions used in this analysis.

- **Demand**: The hourly demand scenario used for this analysis is the Final 2024 CED Planning Forecast.[42] Additional information on this can be found in CHAPTER 3: California Energy Security Plan

The 2021 Infrastructure Investment and Jobs Act requires State Energy Security Plans to be reorganized to:

- Address all energy sources
- Provide an updated state energy profile
- Provide an updated energy sector risk assessment and energy sector hazard assessment
- Address multi-state, tribal, and regional coordination.

States are required each year through October 2025 to submit to the DOE an energy security plan for review or a Governor's letter affirming that the existing plan meets all Section 40108 provisions.

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

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

42 California Energy Commission. "2024 CED Planning Scenario." https://efiling.energy.ca.gov/GetDocument.aspx?tn=262289.

the state has secure, reliable, and resilient energy infrastructure. Recent California Energy Security Plan submission activities include the following:

- In September of 2023, a draft updated California Energy Security Plan was submitted to the DOE Office of Cybersecurity, Energy Security, and Emergency Response (CESER) 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.
- On September 24, 2024, the CEC resubmitted the California Energy Security Plan satisfying the submission requirements.
- On September 29, 2025, the CEC submitted a revised California Energy Security Plan satisfying the submission requirements. The 2025 State Energy Security Plan review and update activities included the following:
    - Updated the California Energy Profile and key data sections with information collected through the first quarter of 2025.
    - Aligned the document with statewide planning documents by incorporating updates from California's most recent emergency, hazard mitigation, and cybersecurity plans.
    - Enhanced the resilience and reliability content by adding details on recent programs, initiatives, and activities.
    - Updated the coordination activities to reflect current regional, federal, and tribal engagement efforts.

The CEC team continues to engage the CESER team and California agencies in support of continued improvement on issues that pertain to energy security and reliability.

- CHAPTER 4:
  Demand Forecast.
- **Conditions Relative to the 1-in-2 Forecast**: This analysis explores 3 system conditions (Table 8).
- **Current RA Planning Standard (average conditions)**: Assumes an 18 percent reserve margin, beginning in 2026.
    - **2020 Equivalent Event**: Includes 50 percent higher forced outages and demand variability, requiring a 22.5 percent reserve margin above the forecasted peak demand.
    - **2022 Equivalent Event**: Increases demand variability to 12.5 percent, aligning with the September 2022 event, and requires a 26 percent reserve margin above the forecasted peak demand.

All these conditions were also evaluated under a scenario where delays in new resource development could temporarily limit available capacity, as well as a coincidental fire risk that reduces total import capacity by up to 4,000 MW, similar to the impacts observed during the 2021 Bootleg Fire in Oregon.

Table 8: System Conditions Defined

Condition Relative to 1-in-2 Forecast	Operating Reserves	Outages	Demand Variability	Coincidental Fire Risk (MW)	Notes
Current RA Planning Standard – 18%	6%	5%	7%	0	18% beginning 2026
2020 Equivalent Event: Additional capacity needed to weather heat event like 2020	6%	7.5%	9%	4,000	9% higher demand over median, and 2.5% higher levels of outages
2022 Equivalent Event: Additional capacity needed to weather heat event like 2022	6%	7.5%	12.5%	4,000	12.5% higher demand over median, and 2.5% higher levels of outages

Source: CEC Staff – January 20, 2023, Lead Commissioner Workshop

- **California ISO 2026 NQC List:**[43] Used for existing resources in the 2026 summer stack analysis.
- **Resource Updates**: Two resource builds are used in this analysis. The first is based on mid-term reliability procurement with additional resource builds. The second is based on California ISO interconnection queue data.[44] For the purposes of the stack analysis, the mid-term reliability procurement and TPP portfolio are used for the 10-year outlook for years 2027 to 2036 while the near-term 2026 preliminary summer outlook used the California ISO queue data.
- **Demand Response:** The IOU DR monthly projections are published by the CPUC.[45] These numbers are used in addition to the CPUC's 2025 NQC list for the baseline DR. The DR numbers in Table 9 are assumed to be fixed to 2035 because the IOUs do not forecast or report DR numbers to a 10-year horizon.

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43 California ISO. *Net Qualifying Capacity Report for Compliance Year 2026*. https://www.caiso.com/notices/2026-net-qualifying-capacity-values-for-resource-adequacy-resources-2.

44 California ISO. *Generator Interconnection Resource ID Report*. https://www.caiso.com/Documents/Generator-Interconnection-Resource-ID-Report.xlsx.

45 California Public Utilities Commission. *Supply Side Demand Response Totals*. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

Table 9: 2026 Aggregated DR Numbers Reported by IOUs

	July	August	September
Demand Response (MW)	884	802	794

Source: CEC Staff with Load Impact Protocol Report data

- **RA Imports:** Standard imports are set to 5,500 MW in every hour. The 5,500 MW of fixed RA imports was set in consultation with California ISO and CPUC. The value is consistent with modeling approaches used by both entities. In addition to the 5,500 MW of RA imports, the stack analysis includes contributions from new out-of-state wind resources on new transmission interconnected directly into the California ISO above this total RA import number, consistent with CPUC modeling for the PSP.
- **Wind and Solar:** The CEC uses hourly shapes to estimate generation from onshore wind and solar located within the California ISO BA footprint. These are based on historic generation on high-load days between 2014 and 2024. Out-of-state wind resources are included in the stack based on the expected effective load carrying capability values for those resources.[46]
- **Battery Storage:** Battery storage is limited to 6 hours of total discharge within a 24-hour stack. This means a four-hour battery may discharge at full output for four hours, at half output for eight hours, or in any combination that does not exceed the total daily energy limit. Battery storage is dispatched first to the hours with the largest capacity shortfalls and continues until the battery storage is exhausted or when all shortfalls have been eliminated. If energy remains, the remaining capacity is evenly distributed across the evening peak hours. The full nameplate capacity for battery storage is included in the stack, rather than the expected effective load carrying capability values because discharge limits are directly incorporated. See Hourly Wind, Solar, and Battery Shapes, below for additional information.
- **Contingency Resources and Retirements:** The stack analysis reflects that the Once-Through-Cooling (OTC) plants have been removed from the supply stack and considered as contingency resources under the SRR and that Diablo Canyon Power Plant (DCPP) retires based on new retirement dates of October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2). Diablo Canyon Power Plant Units 1 and 2 are assumed to be offline by end of 2030, resulting in 2,280 MW of net qualifying capacity reduction to the supply stack.

Supply Delay Scenarios

Given that there are uncertainties in when new clean energy resources may come online (for example, supply chain, tariffs, phase-out of tax credits, construction, interconnection, and permitting), the analysis looks at different scenarios that might affect timely online dates. The delay scenarios assume that each year a percentage of resources will be delayed in the current summer but will be available in the next summer. Scenarios were run for a 0 percent delay, 20 percent delay and a 40 percent delay.

Transmission Planning Process (TPP) Portfolio

46 California Public Utilities Commission. *2023 CPUC IRP PSP – Resolve Public Release v1.0.2*. https://files.cpuc.ca.gov/energy/modeling/LTPP/2023%20CPUC%20IRP%20PSP%20-%20Resolve%20Public%20Release%20v1.0.2.zip.

The CPUC provided information on the projected new resources based on the total resource build for the TPP portfolio from the February 2025 decision.[47] This resource build portfolio includes resources counting towards MTR targets and additional resource builds beyond the MTR. The total nameplate capacity added for this scenario is provided in Table 10. Because CPUC-jurisdictional LSEs procure resources to meet binding procurement orders, while the TPP Portfolio includes additional resources intended to achieve broader GHG emissions reduction and reliability goals, the TPP Portfolio represents a more optimistic view of resource development in the mid- and long-term compared to the procurement orders. However, the battery additions are consistent with recent build rates, while out-of-state wind additions appear reasonable given the 2026 in-service date SunZia transmission project.

Table 10: Total Builds in TPP Base Case Portfolio (Nameplate MW)

Resource Type	2026	2027	2028
Geothermal	116	232	348
Biomass/Biogas	0	0	0
Hydro	0	0	0
In-State Wind	250	500	750
Out-of-State Wind	1436	2186	2936
Solar	3998	9499	15000
Battery Storage (4-hr)	3908	5310	6712
Battery Storage (8-hr)	178	613	1048
Location Constrained Storage (12-hr)	0	0	0
Shed DR	0	0	0
TOTAL	**9887**	**18340**	**26794**

*Values are cumulative and in nameplate capacity.

Source: CPUC Data

Hourly Wind, Solar, and Battery Shapes

Hourly wind shapes and solar shapes were developed from California ISO-wide aggregated generation profiles, normalized to installed capacity, for each hour from 2014-2024. Using historic hourly demand data from the California ISO OASIS portal, the median wind and solar generation values for each hour of the day was calculated based on the five highest-load days of each month for each year 2014-2024. The 20th percentile for both wind and solar generation values is calculated similarly. The profiles are a weighted average of the median and the 20th percentile, with 80 percent of the weight going to the median and 20 percent to the 20th percentile. This weighting method is similar to the NQC approach for projecting non-dispatchable hydro capacity.

$$\text{Hourly Profile} = (0.2 \times 20^{th}\text{ Percentile}) + (0.8 \times \text{Median})$$

Battery storage and long duration storage are optimized so that the energy shortfall does not result in numbers higher than the capacity shortfall. The profile is created in five steps:

47 California Public Utilities Commission. *DECISION TRANSMITTING ELECTRICITY RESOURCE PORTFOLIOS*. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M557/K879/557879249.PDF.

1. Find the capacity shortfall. This is the highest shortfall in any hour with the batteries discharging at full capacity.
2. Then, spread the battery discharge out so that in any hour that has a shortfall without battery discharge, the shortfall in that hour is less than or equal to the capacity shortfall.
3. If there is battery capacity remaining after step 2, the battery discharge is used to eliminate the smallest hourly shortfall or reduce it as much as the capacity and power of the batteries allows.
4. Step 3 is repeated until the battery discharge reaches four total hours.
5. If every hour has either no shortfall or the maximum hourly battery discharge before total discharge reaches four hours, the remaining discharge is split evenly between the 4 and 10 PM hours[48] that have not reached maximum hourly discharge.

Table 11 shows the hourly profile used for solar, wind and battery resources. While the solar and wind profiles remain unchanged throughout the analysis, the battery profile changes to reduce the shortfalls. Therefore, the battery profile in Table 11 is for 2026 September peak hours, which was created using the California ISO supply case with a 40 percent delay. The California ISO supply scenario with a 40 percent delay is the extreme case in 2026-4; thus, the battery profile is optimized to reduce the shortfalls as much as possible across all critical hours.

Table 11: Wind, Solar, and Battery Hourly Profiles

Time (PDT)	Jul - Wind	Aug - Wind	Sep - Wind	Jul - Solar	Aug - Solar	Sep - Solar	Jul - Battery	Aug - Battery	Sep - Battery
4PM-5PM	0.46	0.35	0.18	0.56	0.55	0.41	0.39	0.48	0.35
5PM-6PM	0.49	0.40	0.21	0.32	0.25	0.10	0.42	0.51	0.66
6PM-7PM	0.51	0.42	0.25	0.07	0.03	0.00	0.77	0.85	1.00
7PM-8PM	0.54	0.47	0.27	0.00	0.00	0.00	1.00	0.98	1.00
8PM-9PM	0.55	0.49	0.28	0.00	0.00	0.00	0.84	0.71	0.64
9PM-10PM	0.56	0.50	0.28	0.00	0.00	0.00	0.58	0.48	0.35

Source: CEC staff utilizing California ISO data

Annual Results

The annual results discussed are the maximum capacity shortfalls found in each of the deterministic scenarios introduced above, within each reliability year (defined as year ending

48 Typical hours cover peak and net-peak. However, hours expanded further to allow battery discharge to apply to tail-end hours.

September 30). It should be noted that the deterministic scenarios are not directly tied to any particular probability; however, insights can be drawn from the results relative to one another.

2026 Expected New Resources

As in previous quarterly reports, staff adopted a more conservative approach for counting new resources due to the uncertainty in project development timelines. This approach excludes projects that show no clear indication of progressing toward commercial operation.

As of October 1, 2025, a total of 1,788 MW of new capacity is still slated to come online by the end of 2025, with an additional 223 MW of new resources currently expected in early 2026. The values shown in Table 12 are cumulative totals of the capacity expected to be online by each listed month. The majority of these additions come from battery storage and solar projects, which continue to represent the largest share of new nameplate capacity added to the system. This forecast reflects the best available information at the time of analysis and will continue to evolve as new project data become available.

Table 12: Expected New Resource Additions

Resource Type	Oct 2025	Nov 2025	Dec 2025	Jan 2026	Feb 2026	Mar 2026	Apr 2026	May 2026	June 2026
Battery	844	884	884	884	969	1,019	1,019	1,019	1,019
Geothermal	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0
Other	0	2	2	2	2	2	2	2	2
Solar	712	754	899	902	987	987	987	987	987
Wind	0	0	0	0	0	0	0	0	0
Total Expected	**1,556**	**1,640**	**1,785**	**1,788**	**1,958**	**1,958**	**1,958**	**1,958**	**1,958**

Source: California ISO New Resource Implementation. Accessed 10/01/2025.

California ISO Area: Updated Resource Stack for Summer 2026

As shown in Table 13, several changes have been made to the resource stack since the release of the *2025 Fourth Quarterly Joint Agency Reliability Planning Assessment.* This analysis continues to focus on Hour 18 of September, the period of highest reliability risk due to peak demand and lower renewable generation output.

Since the last report, total available supply has decreased by more than 1,800 MW due to a combination of factors. Updates to the 2026 NQC data show lower available capacity, though this number is expected to increase as additional resources are certified closer to summer. The decrease also reflects a reduction in DR capacity, which dropped by about 240 MW, and a decline in forecasted new resources, as some resources are not expected to achieve their originally scheduled 2025 online dates. These delayed projects are not included in the current stack analysis and will be added back once updated data confirm their revised operational timelines and capacities. In contrast, battery capacity continues to grow, with more than 450 MW of new storage included in this analysis.

On the demand side, the forecasted September peak demand increases by 564 MW for 2026. These figures are based on the 2024 CED Forecast and are expected to be refined once the 2025 CED forecast becomes available.

Table 13: Comparison of Summer Assessment Results for September 2025, Hour 18 to September 2026, Hour 18

	2025 4th Quarterly Report	2026 1st Quarterly Report	Change Since Last Update
Supply			
Existing Resources [49]	49,122[50]	48,746[51]	▼**376**
Solar	1,769	1,771	▲**2**
Wind	1,307	1,307	**0**
RA Imports	5,500	5,500	**0**
Demand Response	1,033	794	▼**239**
Expected New Resources[52]	2,307[53]	1,050[54]	▼**1,257**
Total (MW)	**61,038**	**59,498**	▼**1,870**
Demand			
Sept. Peak Demand	**46,094**	**46,658**	▲**564**
Surplus/Shortfalls			
Planning Standard	7,319	4,442	▼**2,877**[55]
2020 Equivalent Event	4,794	2,342	▼**2,452**
2022 Equivalent Event	3,187	708	▼**2,479**

Source: CEC staff with California ISO data

The stack analysis in this report shows surpluses of over 4,400 MW under average planning standard conditions, up to 2,300 MW for a 2020 equivalent event, and over 700 MW for a 2022 equivalent event. Compared to the previous quarterly report, these values represent a significant decline across all scenarios.

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49 "Existing resources" refer to the amount of firm, dispatchable energy capacity currently available on the grid. This category excludes intermittent resources such as solar and wind generation.

50 This value was calculated using the 2025 vintage Final NQC List, with a data date of August 11, 2025.

51 This value was calculated using the 2026 vintage Final NQC List, with a data date of October 15, 2025.

52 "New resources" refers to the sum of expected new generation capacity projected to come online, with adjustments made based on their hourly generation profiles, where applicable (e.g., for solar, wind, or batteries).

53 This value was calculated using California ISO New Resource Interconnection Queue, with a data date of August 11, 2025.

54 This value was calculated using California ISO New Resource Interconnection Queue, with a data date of October 15, 2025.

55 The planning standard has been updated to reflect a higher Planning Reserve Margin, increasing from 17% in the previous report to 18% starting in 2026.

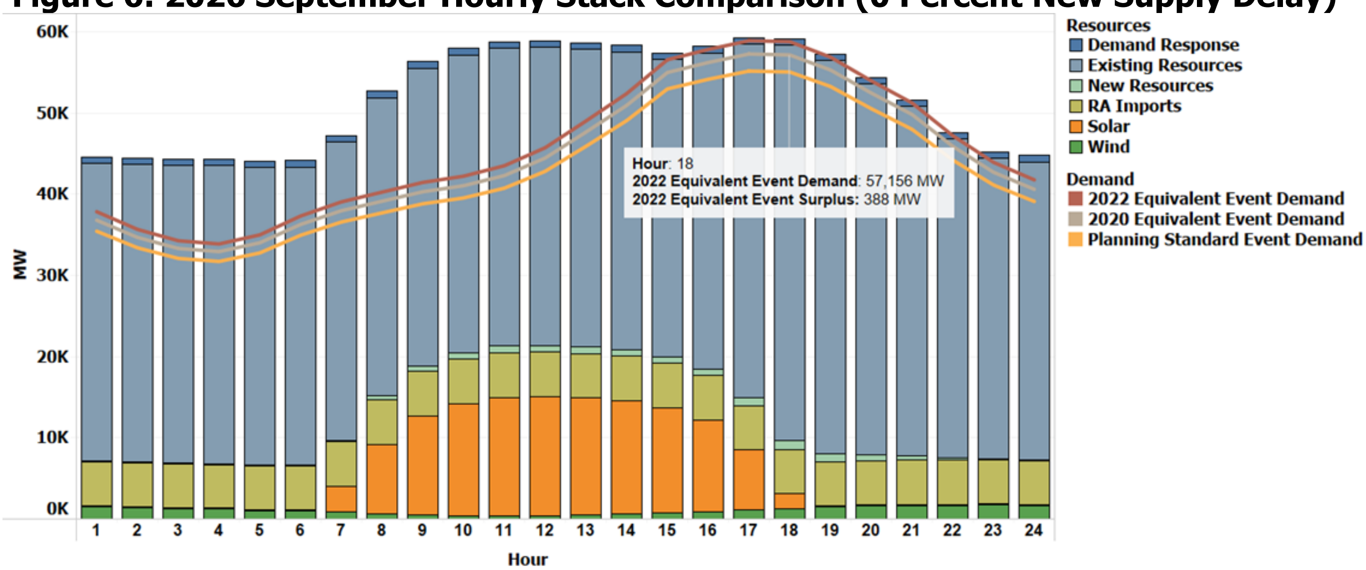
As shown in Table 13, the largest driver of the decrease in supply is the reduction in expected new resources, which declined 1,250 MW compared to the previous report. This reflects delays in project development and interconnection timelines, resulting in the exclusion of these resources from the current stack. In addition, the updated 2026 NQC data shows lower available capacity with the largest reduction coming from hydro resources, which declined by over 400 MW. This decline was primarily due to hydro condition uncertainty for 2026. The remaining NQC data changes are from the small adjustments in revised NQC values.

Alongside these supply side changes, September peak demand is forecasted to increase over 560 MW from the previous summer. In addition to the increase in demand, the PRM for the planning standard increased from 17 to 18 percent starting in 2026, raising the required capacity by more than 460 MW.

Additional Reliability Risks

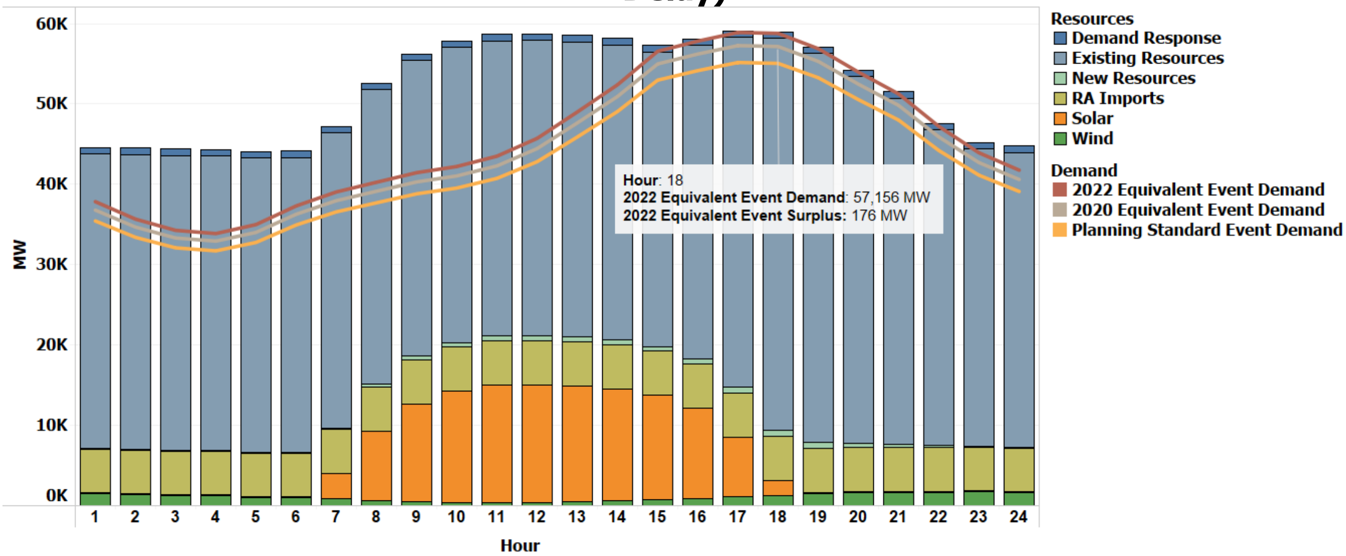
Outside of extreme heat events, the stack analysis results do not account for other potential risks, outside of extreme heat, to reliability, including delays in new resource development and wildfire related transmission constraints. New supply delays can occur for several reasons, including supply chain challenges, permitting barriers, transmission and interconnection issues. If expected new resources are delayed by up to 40 percent, the grid still shows sufficient supply to maintain reliability under planning standard and 2020 equivalent event conditions. However, if a 2022 equivalent event were to occur under the same 40 percent delay, the system would require up to 35 MW of contingencies during hour 18, the peak demand hour. Figure 8 illustrates how hourly supply compares to demand during a 2022-equivalent event with a 40 percent delay in new supply. A 40 percent delay in expected new resources would reduce available capacity by roughly 400 MW from the current supply stack. Even with this reduction, the system is projected to retain sufficient capacity to meet planning standard conditions.

Figure 6: 2026 September Hourly Stack Comparison (0 Percent New Supply Delay)



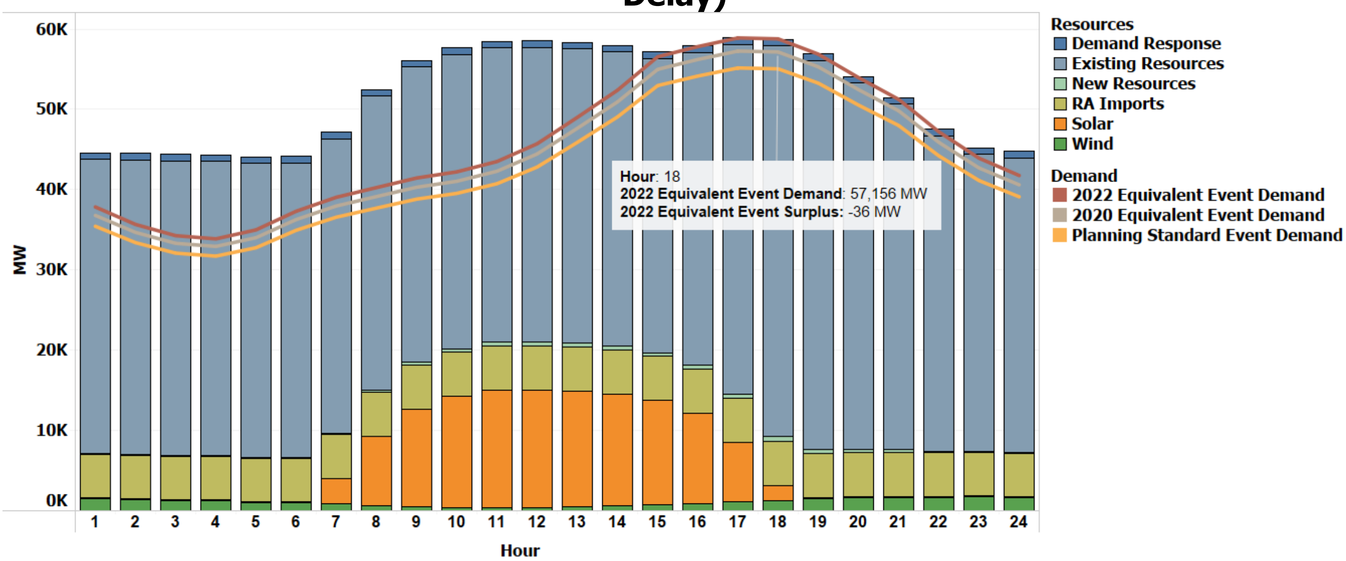
Source: CEC

Figure 7: 2026 September Hourly Stack Comparison (20 Percent New Supply Delay)



Source: CEC

Figure 8: 2026 September Hourly Stack Comparison (40 Percent New Supply Delay)



Source: CEC

Wildfire remains another major source of uncertainty, with the potential to reduce capacity primarily through impacts on major transmission corridors such as the COI which lost up to 4,000 MW of import capability from the Bootleg fire in 2021. Modeling of a similar outage scenario indicates that under typical conditions, the system is expected to remain reliable even with such transmission losses. However, if a wildfire related outage were to coincide with extreme heat, there could be a need for contingencies up to 1,600 MW and 3,200 MW under 2020 and 2022 equivalent events, respectively.

Table 14: Reliability Impacts from COI Outage Wildfire Scenarios

System conditions	Surplus/Shortfalls
Planning Standard	**442 MW**
2020 Equivalent Event	**-1,658 MW**
2022 Equivalent Event	**-3,292 MW**

Source: CEC staff

5-Year Overview (2027 to 2031):

Within the 5-year horizon, the planning standard resulted in surplus in all scenarios through 2031. This is an improvement compared to the previous 5- and 10- year outlook in the 2025 Combined First and Second Quarterly *Joint Agency Reliability Planning Assessment*, where shortfalls were observed starting in 2032. This improvement is due to additional resources selected in the TPP portfolio that were incremental to the PSP used in last year's assessment. Note that these scenarios, as shown in Figure 9, do not include a coincident event of transmission capacity loss from a wildfire.

10-Year Overview:

This section explores the supply and demand balance in the 10-year horizon using 0, 20, and 40 percent project delay adjustments to the TPP supply (Table 10: Total Builds in TPP Base Case Portfolio (Nameplate MW)) in each year. The annual supply was compared to a planning standard (average conditions) of an 18 percent reserve margin. Then, the annual supply was compared to more extreme events, which were defined as a 2020 event and a 2022 event – consistent with previous report extreme scenarios.

Under the average conditions, the TPP portfolio resulted in surplus for all delay scenarios until 2033, which is due to no new supply being built after 2028 and the gradual demand increase year to year. The max shortfall observed, in average conditions, was 6,400 MW in 2035 (Figure 9). The shortfalls observed, starting in 2033, could indicate that there is a potential need for additional resources.

Figure 9: 10-Year Stack Analysis - Hour 18

	New Resource Delay	Year 2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
2022 Event	40	3,400	2,800	400	0	-2,000	-3,800	-5,700	-7,800	-9,900	-11,300
	20	3,700	3,100	700	0	-2,000	-3,800	-5,700	-7,800	-9,900	-11,300
	0	4,000	3,300	900	0	-2,000	-3,800	-5,700	-7,800	-9,900	-11,300
2020 Event	40	5,100	4,500	2,200	1,900	-100	-1,800	-3,700	-5,700	-7,800	-9,200
	20	5,400	4,800	2,500	1,900	-100	-1,800	-3,700	-5,700	-7,800	-9,200
	0	5,600	5,000	2,700	1,900	-100	-1,800	-3,700	-5,700	-7,800	-9,200
Average Conditions	40	7,200	6,700	4,500	4,200	2,400	700	-1,100	-3,000	-5,000	-6,400
	20	7,600	7,000	4,800	4,200	2,400	700	-1,100	-3,000	-5,000	-6,400
	0	7,800	7,200	5,000	4,200	2,400	700	-1,100	-3,000	-5,000	-6,400

Source: CEC staff with CPUC data

When considering the impacts of extreme events, the outlook becomes worse with 2036 having a 11,000 MW shortfall in a 2022 equivalent event. It is important to note that DCPP Units are currently planned to be fully retired beginning in 2031, with one unit retiring in 2030.

Another element to consider in addition to extreme events, which can worsen an already strained power grid, is loss of transmission. The effects of losing 4,000 MW in the 10-year horizon leads to shortfalls in most years, including shortfalls under average planning standard conditions starting in 2030 and greatly increasing the shortfalls in the most extreme events, up to 15,000 MW.

After 2026, the expiration of the SRR removes a program designed to provide additional reserve capacity during periods of tight system conditions. This change aligns with the scheduled retirement of OTC units, which will reduce the pool of dispatchable reserve resources that were quickly established or extended to manage tight conditions after the summer of 2020. However, at the same time, new and existing programs are continuing to grow and evolve to prevent or respond to emergency events and to transition away from temporary programs such as DSGS and ELRP. These programs include many types of load shifting and virtual power plant options, including PG&E's Automated Response Technology program and EV Connect, SCE's Behind the Meter Optimization of Load Technology, and capacity bidding programs and critical peak pricing programs, among others. There is also the possibility of continuing the Resource Adequacy program's Effective Planning Reserve Margin, which currently adds approximately 1,260 to 2,300 MW to the summer 2026 and 2027 planning standard and could be used to reduce the likelihood of tight operating margins during extreme events in the future.

Comparison to Past Stack Analyses

The Stack Analysis began in early 2021 in response to the August 2020 blackouts as a way to quickly assess near-term, worst-case reliability scenarios. The first few iterations assessed summer 2021 and 2022 and focused on the implications of solar dropping off in the late evening and hydroelectric resources losing effectiveness during drought conditions. In 2022, the CEC extended the time horizon for the stack analysis to assess planning priorities out to 2026. The analysis was expanded in part to evaluate the impacts of OTC retirements. Hourly shapes for wind, solar, and other new resources were introduced to better represent the limitations of resources the state will rely on in the future.

For summer 2026, the stack analysis incorporates updated hourly shapes for wind and solar, while battery shapes remain unchanged. Additionally, RA imports remain fixed at 5,500 MW. Initial projections for 2026 are based on California ISO New Resource Implementation Queue data, enabling the CEC stack analysis to more accurately evaluate the need for contingency resources based on resources coming online beyond what has already been ordered and contracted.

Table 15 below shows the progression of the stack analysis during 5-6 PM in September. Table 15 includes the average and elevated reserve margins and shortfall numbers at the same hour. Assuming that all projected resources come online by the start of summer, this will be the second year in a row that no shortfalls were observed under extreme scenarios.

Table 15: Summer Stack Results from September 2021 to January 2026

Publication Date	Summer Assessed	Average Reserve Margin	Average Shortfall (MW)	Elevated Reserve Margin	Extreme Shortfall (MW)*
Sep 2021	2021	15%	60	17.5%	1,180
Sep 2021	2022	15%	980	22.5%	4,350
May 2022	2022	15%	40	22.5%	3,500
May 2022	2023	15%	0	22.5%	600
Jan 2023	2023	16%	0	26%	2,700
May 2024	2024	17%	0	26%	90
Jan 2025	2025	17%	0	26%	0
Jan 2026	2026	18%	0	26%	0

*Elevated Reserve Margin definition: 26% elevated reserve margin is equivalent to a 2022 September heat event and 22.5% elevated reserve margin is equivalent to a 2020 August heat event.

Source: CEC Staff

SB 1020

SB 1020 sets interim targets to SB 100 of 90 percent by 2035 and 95 percent by 2040, and requires the CPUC, CEC, and CARB, to annually issue a joint reliability progress report that:

- reviews system and local reliability within the context of the SB 100 and SB 1020 interim targets, with a particular focus on summer reliability
- identifies challenges and gaps, if any, to achieving system and local reliability
- identifies the amount and cause of any delays to achieving compliance with all energy and capacity procurement requirements set by the CPUC

California ISO 2026 Local Capacity Area Technical Study

To satisfy the requirements of SB 1020, this report draws on insights from the California ISO 2026 Local Capacity Area study.[56] The technical study focuses on addressing the minimum capacity necessary in identified transmission-constrained "load pockets" or local capacity areas to ensure compliance with mandatory reliability standards.

The concept of local capacity requirements (LCR) predates the 1998 restructuring of the California electric system. Before restructuring, investor-owned utilities made deliberate trade-offs between investing in transmission and generation, relying on local generation to supplement transmission capacity in certain areas. While electric restructuring did not alter the physical need for local generation, it changed the means of accessing such resources. Following restructuring, the California ISO entered contracts with ”reliability must-run” generation to meet local reliability needs. The state's adoption of RA requirements has shifted the procurement of resources to LSEs, aligning with the technical study to ensure sufficient local generation for reliability standards.

The assumptions and processes employed in the 2026 Local Capacity Technical (LCT) Study align closely with those utilized in the 2007-2025 LCT Studies. However, the 2026 LCT study used the CEC’s 2024 IEPR demand forecast.[57] Since the release of the 2026 LCT study, a new CEC IEPR demand forecast has been released. Overall, the capacity required for LCR, from 2025 to 2026, increased by approximately 234 MW, or 1.03 percent.

The specific areas with decreased LCR needs include Humboldt, Bay Area, Sierra, Stockton, Fresno, North Coast/North Bay and Big Creek/Ventura due to load forecast decreases. Between 2025 and 2026, the LA Basin, Big Creek/Ventura, and Greater Bay Area experienced the largest changes in Local Capacity Requirement needs. The Los Angeles Basin saw the most significant increase, with its LCR need rising by approximately 1,689 MW, from 4,123 MW in 2025 to 5,812 MW in 2026.

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56 California ISO. 2025. 2026 LOCAL CAPACITY TECHNICAL STUDY.

https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-2026-Local-Capacity-Technical-Report.pdf.

57 *CED 2024 Planning Forecast LSE and BAA Tables*.

https://efiling.energy.ca.gov/GetDocument.aspx?tn=262788.

Table 16: 2026 Final LCR Needs (MW)

	August Qualifying Capacity (AQC)	AQC	AQC	AQC	Capacity Available at Peak	2025 LCR Need	2026 LCR Need
Local Area Name	**QF/ Muni**	**Non-Solar**	**Solar**	**Total**	**Total**	**Capacity Needed**	**Capacity Needed**
Humboldt	0	174	0	174	174	164	136
North Coast/ North Bay	135	893	0	1,028	1,028	967	848
Sierra	1,236	707	0	1,943	1,943	1,532	1,354
Stockton	130	613	15	758	743	735	756
Greater Bay	596	7,902	8	8,506	8,501	7,441	7,558
Greater Fresno	205	3,194	440	3,839	3,399	2,532	2,100
Kern	12	377	71	460	389	434	452
Big Creek/ Ventura	448	4,258	400	5,106	5,106	2,145	1,369
LA Basin	1,266	9,481	29	10,776	10,776	4,123	5,812
San Diego/ Imperial Valley	3	5,893	243	6,139	6,139	2,709	2,631
Total	**4,031**	**33,491**	**1,206**	**38,729**	**38,198**	**22,782**	**23,016**

Source: California ISO

The results of the 2026 LCT Study are forwarded to the CPUC for consideration in its 2026 RA requirements program. These results will be utilized by the California ISO as "Local Capacity Requirements" to determine the minimum local capacity necessary to meet the LCR criteria. Additionally, the results assist in allocating costs for any California ISO procurement of capacity required to achieve Reliability Standards, independent of the RA procurement by LSEs. California ISO will finalize a 2027 LCT study in the second quarter of 2026.

CHAPTER 8: Mid-Term Probabilistic Reliability Assessment (CEC)

The CEC performed a probabilistic assessment of the mid-term statewide reliability outlook for California from 2031 to 2036, under the supply forecast in the CPUC's Adopted 2023 PSP. The goal of this analysis was to determine if California is meeting the reliability criterion of 1 day in 10-year LOLE, or 0.1 days/year LOLE with the planned retirement of DCPP. The nuclear plant has a current retirement date of 2030. The probabilistic assessment incorporates multiple reliability risks, combining uncertainty in resource availability, hourly demand, unexpected generator outages, and lower than expected imports. This analysis was conducted throughout all months in each year to better understand the shifting reliability risk over the study horizon due to changes in the load and resource mix.[58]

The study finds that the current resource mix and proposed PSP additions for CPUC-jurisdictional LSEs and supply from additions for POUs contain resources sufficient to exceed the 0.1 LOLE reliability criterion and serve load under challenging demand and resource conditions. The scenario evaluated in this analysis show increasing winter risk after 2035. The most recent *California Energy Resource and Reliability Outlook, 2025* (*CERRO*)[59] has shown this to be an emerging trend. However, neither this study nor the *CERRO* evaluates all potential risk, and future work is being conducted to evaluate wildfire risks, the impacts of transmission outages, and reduced availability of new resources or imports, among others. Additionally, alternative load scenarios, such as increased or different electric vehicle charging patterns, may drive summer reliability risks not captured here. While the study results show that California is expected to meet or exceed its reliability targets across the broad risk under study, higher than expected temperatures across the Western Interconnection, combined with drought and transmission outages could lead to loss of load.[60]

That said, system reliability is expected to continue to significantly improve in the near-term due to (1) significant new resource additions (including utility-scale solar, wind, and batteries, and distributed rooftop solar), (2) new energy efficiency and DR programs, (3) the near-term retention of DCPP up to October 31, 2030, and (4) projected reduction in summer peak demands relative to those that were used to design the generation mix used in this study (the 2023 PSP). Without DCPP as a part of California's resource mix, the details regarding reliability risk may evolve, as DCPP is a 24-hour firm, clean resource. Planned retirement of the nuclear

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58 For this analysis, the 2024 CED Demand Forecast update, released March 2025, was implemented in the model.

59 Yee Yang, Chie Hong, Kristen Widdifield, Liz Gill, Jake McDermott, Justin Cochran, Joseph Merrill, Bryan Neff, Jason Orta, Matthew Cooper, Paul Deaver, Ashley Emery, Justin Szasz, and Michael Nyberg. July 2025. *California Energy Resource and Reliability Outlook, 2025*. California Energy Commission. Publication Number: CEC-200-2025-011.
https://efiling.energy.ca.gov/GetDocument.aspx?tn=264559&DocumentContentId=101432.

60 The CPUC is considering adding 6,000 MW of net quality capacity for the 2029-2032 timeframe through Rulemaking 25-06-019 (see Chapter 5: Supply Forecast). This addition is not considered in this analysis.

plant confirms the conclusion from previous reliability reports that California will continue to meet 0.1 LOLE reliability criteria through 2036 under the 2023 PSP.[61] Results of the scenarios and sensitivities are provided in Table 17.

Table 17: Resource Adequacy Results Across Scenarios

Results	Units	2031	2036
Base Case, Planned Retirement of DCPP	LOLE (days/year)	0.00	0.02

Source: CEC staff

Model Development and Key Assumptions

To evaluate the RA of California's power system under a variety of scenarios, a probabilistic, hourly, chronological RA simulation was conducted in the PLEXOS modeling software. This software is also utilized by other California entities for RA, including the California ISO. This California RA model was developed using public information to the maximum extent possible. Where relevant, CEC aligned key inputs and assumptions with the CPUC RA Study and the California ISO Summer Reliability Assessments.

Notable Updates from Previous SB 846 Joint Agency Reliability Planning Assessment Reports[62]

While the overall model is consistent with previous analysis conducted by the CEC, there are notable updates that have been made over the past several months. On net, these changes have improved the modeled reliability outlook for California. The list below provides an overview of the major changes implemented in the model.

- **Demand Update** – The CEC issued a revision to the 2024 CED, which lowered forecasted peak loads and classified data center load as a distinct load modifier from the original forecast. The net peaks increased relative to the previous 2023 CED and the load forecast used to develop the PSP.
- **California ISO import constraint extension** – The maximum import constraint was extended to morning (hours 6-9) and evening (hours 16-22) peaks across the whole year, to constrain imports during peak hours of wintertime loads. This change was made due to the finding from the 2025 CERRO analysis that California faces increased risk during the

61 Yee Yang, Chie Hong, Kristen Widdifield, Liz Gill, Jake McDermott, Justin Cochran, Joseph Merrill, Bryan Neff, Jason Orta, Matthew Cooper, Paul Deaver, Ashley Emery, Justin Szasz, and Michael Nyberg. July 2025. *California Energy Resource and Reliability Outlook, 2025*. California Energy Commission. Publication Number: CEC-200-2025-011.
https://efiling.energy.ca.gov/GetDocument.aspx?tn=264559&DocumentContentId=101432.

62 Yee Yang, Chie Hong, and Brendan Burns (CPUC). April 2025. Joint Agency Reliability Planning Assessment. California Energy Commission. Publication Number: CEC-200-2025-004.
https://efiling.energy.ca.gov/GetDocument.aspx?tn=265662&DocumentContentId=102509

winter.[63] It is a conservative estimate that imports could be limited in the winter as supply in the west tightens. This import assumption will be explored more in future reports as electrification continues.
- **Stochastic loads** – The CEC developed underlying stochastic load profiles aligned with historical weather patterns. These profiles ensure the simulated electricity demand follows similar chronological weather patterns as the simulated solar and wind profiles. The utility-scale solar, distributed solar, and land-based wind profiles are based on historical weather years (see Table 20).
- **Inclusion of 2022 and 2023 weather years** – The weather years underpinning the modeling and analysis were expanded to include 2022 and 2023. This expansion was done across load, wind, and solar profiles.
- **Renewable availability profiles** – The underlying development process for utility-scale renewable plant profiles was updated to capture increased granularity of project siting to improve modeling accuracy.
- **Updated outage modeling** – The natural gas outage sampling in PLEXOS was updated to better align to the NERC Generating Availability Data System Forced Outage Factor. The net effect reduced the modeled forced outage rate, making the gas fleet more reliable.

Model Topology

The CEC's RA model is California-centric, meaning power plants for the state are modeled in detail, but areas outside the state are represented as generic imports. California is modeled as seven regions, including the three investor-owned utility service areas (PG&E, Southern California Edison, and San Diego Gas &Electric), which are grouped together as California ISO when appropriate, as well as four publicly owned utility BAAs (BANC, Turlock Irrigation District, Los Angeles Department of Water and Power, and Imperial Irrigation District). Transmission is represented between the regions. The California ISO regions have a total California ISO import limit of 11,665 MW, and 5,500 MW during reliability risk hours (H6-9 and H16-22 throughout the whole year).[64] Imports into California are limited at 12,450 MW in all hours of the day, subject to monthly energy limits. The statewide import constraint is the 95th percentile of historic imports reported on Energy Information Administration (EIA) Form 930.

LOLE results are reported for the entire state, though the California ISO regions experience most of the loss of load events.

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63 Yee Yang, Chie Hong, Kristen Widdifield, Liz Gill, Jake McDermott, Justin Cochran, Joseph Merrill, Bryan Neff, Jason Orta, Matthew Cooper, Paul Deaver, Ashley Emery, Justin Szasz, and Michael Nyberg. July 2025. *California Energy Resource and Reliability Outlook, 2025*. California Energy Commission. Publication Number: CEC-200-2025-011.

64 The 5,500 MW figure exceeds the 4,000 MW figure that has been used in California ISO models due to the treatment of pseudo-tie resources, specifically Palo Verde and Hoover. Palo Verde and Hoover are treated as generic imports in the CEC RA model but are modeled explicitly in the California ISO RA model.

Generation from pseudo-tie units, such as Palo Verde, Hoover, and other jointly owned resources located outside of the state are modeled as generic imports and generation from these units counts against the import limits listed above.[65]

Demand Forecast

This analysis utilizes the revised 2024 IEPR CED forecast. The underlying demand and behind-the-meter solar layers are assumed to be weather dependent and varied across weather years. The model uses weather correlated demand and renewable shapes for 17 weather years representing 2007 to 2023. The 2024 CED load forecast is then scaled to the 17 different weather years. All other load modifiers (i.e., building electrification, electric vehicles, and energy efficiency) do not vary by weather year.

Of note, the 1-in-20 peak forecast modeled in this report ranges from 650 MW to 285 MW lower between 2025 and 2027, as compared to the 2022 CED used to develop the resource mix in the 2023 PSP, shown in Figure 10.[66] From 2028 to 2035, the forecast then ranges from 1,100 to 8,700 MW higher. As a result, the downward revision in the early years of the demand forecast may mean that the PSP has more resources than necessary to meet reliability targets up to the year 2027. However, the growth in the rest of the demand forecast suggests that it is likely that future PSPs may need more resources to meet long-term reliability targets beyond 2027.[67]

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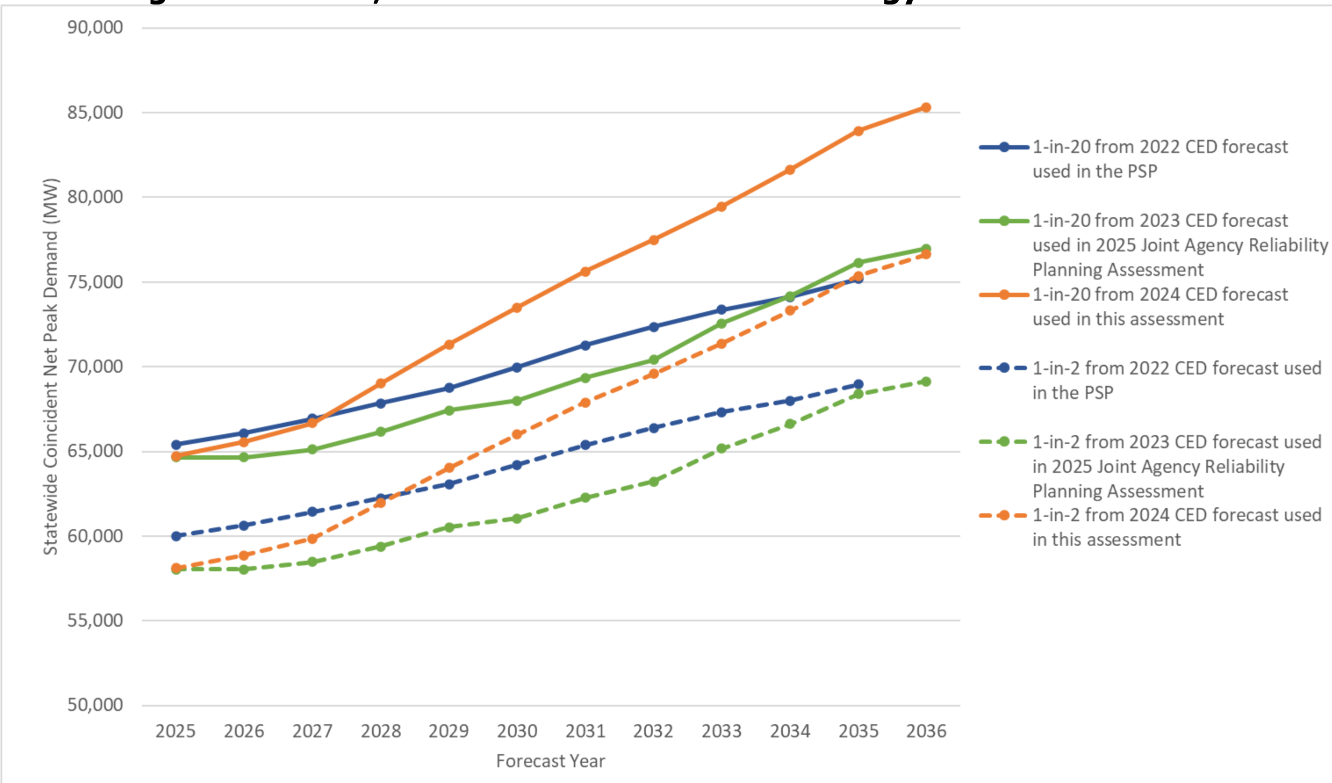
65 The exception to this is the new 840 MW Intermountain gas plant which is connected to LADWP via a high-voltage direct current line and represented as physically located in LADWP's service territory. In addition, consistent with the CPUC's preferred system plan, out-of-state resources available to California are modeled explicitly in each region. For example, the SunZia wind project is modeled as if located within SCE.

66 The demand forecasts used across efforts are the latest that are available. In the case of the 2023 PSP effort, the team used the 2022 IEPR CED Forecast. For this model, the 2024 IEPR CED Update was implemented, which was released in March 2025.

67 The CPUC may potentially order an additional 6,000 MW of net quality capacity for the 2029-2032 timeframe through Rulemaking 25-06-019 (see Chapter 5: Supply Forecast).

Figure 10: 2022, 2023 and 2024 California Energy Demand Forecasts



Source: CEC staff

In addition to the growth in 1-in-2 peak demand compared to the 2022 CED used in the PSP, the updated 1-in-20 peak demand in the 2024 CED is also notably larger than the 1-in-20 peak demand from the 2023 CED used in the *2025 Combined First and Second Joint Agency Reliability Planning Assessment*.[68] The 1-in-20 peak forecast from the 2023 CED ranges from 90 MW to 8,300 MW lower relative to the 1-in-20 peak forecast used in this report.

Resource Additions

All resource additions and retirements for both California ISO and non-California ISO regions were sourced from the CPUC-adopted 2023 PSP released in February 2024.[69] Resource additions 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. Table 18 shows the expansion resources slated to come online across California.

It should be noted that the planning reserve margin constraint in the PSP is often non-binding, meaning that the PSP resource build is driven primarily by the need for new zero-carbon and

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68 Yee Yang, Chie Hong, and Brendan Burns (CPUC). April 2025. *Joint Agency Reliability Planning Assessment*. California Energy Commission. Publication Number: CEC-200-2025-004. https://efiling.energy.ca.gov/GetDocument.aspx?tn=265662&DocumentContentId=102509.

69 CPUC. *2022-2023 IRP Cycle Events and Materials*. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials.

renewable resources to meet GHG emissions reduction targets rather than reliability needs. For that reason, it is expected that the PSP resource build will exceed the 0.1 days/year LOLE criterion. Relatedly, the assumptions in this analysis differ from the CPUC need determination analysis described in Chapter 5 ("Proposed New Procurement Order"), which only assumed a new resource would come online based on whether it was contracted as of June 2025, subject to adjustments. In contrast, this analysis assumed all resources in the 2023 PSP would be contracted, developed, and interconnected on the timeline of the PSP.

The retirements utilized in this analysis align with the PSP. The OTC and generic gas retirements are balanced against the gas additions such that the gas amounts align with the PSP. The PSP had the DCPP retiring in 2024 and 2025.

Table 18: PSP Cumulative Resource Additions (MW)

	2024 Baseline	2025 Additions	2030 Additions	2035 Additions
Peak Load[70]	64,807	64,736	73,502	83,918
Natural Gas	34,527	940	3,840	4,840
Utility Scale PV	25,673	4,606	16,312	21,699
Distributed PV	16,615	1,529	10,708	17,263
Batteries	13,462	4,123	11,958	17,957
Pumped Storage Hydro & Long Duration Storage	4,380	-	785	985
Hydro	9,693	-	-	-
Land Based Wind	9,003	1,367	12,063	18,223
Offshore Wind	-	-	-	4,531
Geothermal	2,970	210	1,538	3,058
Demand Response	2,769	-	-	-
Nuclear	2,393	-	-	-
Other	1,780	-	-	-
Total Incremental Additions	0	12,776	57,205	88,557
Total Resources	123,266	136,041	180,470	211,822

Source: CEC staff

Table 19: PSP Resource Retirements (MW)

	2025	2030	2035
Once Through Cooling	326	1,661	1,661
Generic PSP California ISO Gas Retirements	83	380	1,475

Source: CEC staff

Additional Inputs and Assumptions

Additional inputs and assumptions are provided in Table 20.

70 Represents 1-in-20 coincident peak load for California used in this study.

Table 20: Additional Inputs and Assumptions

Model Input	Data Source	Description
Demand Profiles	CPUC Weather-Sensitive Load	Shapes based on 2022 CPUC shapes Energy and peaks scaled to 2024 IEPR CED revision Load modifiers from 2024 CED
Outage Rates	NERC Generating Availability Data System California ISO Daily Outage Reports	Forced outage rates and maintenance rates are based on U.S. averages, which vary by plant size and fuel type. Battery data based on analysis of California ISO daily outage reports.
Plant Capacities	Quarterly Fuel and Energy Report (QFER)	QFER Data reported in 2024
Expansion Resources	CPUC 2023 PSP	PSP Core Scenario (25 MMT by 2035), February 2024 release
Solar Shapes, 2007-2023	National Renewable Energy Laboratory (NREL) National Solar Radiation Database	Unique solar profiles developed using the NREL System Advisor Model for each significant existing solar plant with capacity-weighted aggregation to regional profiles.
Wind Shapes, 2007-2023	NREL Wind Toolkit (2007-2014) NREL BC HRRR (2015-2023)	Simulated wind production profiles were calibrated to align with actual monthly generation totals from California ISP subpoena data and checked against monthly generation totals reported to EIA 923
Transmission Line Ratings	Western Electricity Coordinating Council (WECC) Path Limits	Applied to imports from WECC regions, Path 46, and for transfers within California.
Hydroelectric Monthly Maximum Ratings	Hourly hydro generation reported in EIA 960	Hydro resources are limited in maximum output based on historical observations, wherein fleetwide maximum generation is well below fleetwide installed capacity. The 2019 hydro year, a relatively average hydro year, is used across simulations.
Hydroelectric Energy Budget	Monthly hydro generation reported in EIA 923, QFER	Maximum hydro generation within a month based on historic generation patterns.
Operating Reserves	6% of Load	Assumes operating reserves of 6% of net load (after reductions for BTM-PV) are held during loss of load events. All other reserves are assumed to be curtailed prior to load shed.

Source: CEC staff

Results

Base Case, Planned Retirement of DCPP - Results

California's power system risk has historically been defined by periods of high temperature and low hydro availability. Near-term RA risks are relatively limited due to the tendency of a heat wave to dissipate as the sun sets. However, the nature of system risk is changing, and this analysis reveals that California's system could become susceptible to winter risk beyond 2035. Diablo Canyon is a firm, clean resource that can provide energy through the night to meet nighttime load and keep California's increasing deployment of batteries charged. When removed from the resource mix, a small amount of unserved energy appears in the RA model during peak hours on winter mornings in 2036. The resulting RA metrics are provided below.

- 2031 Base Case, Planned Retirement of DCPP: No shortfall events
- 2036 Base Case, Planned Retirement of DCPP: 0.02 LOLE

The 2036 LOLE of 0.02 still falls within the LOLE criterion of less than one day of unserved energy in 10 years, or 0.1 LOLE. This shows that the PSP has sufficient planned resources and demonstrates the importance of continuing to build out these resources as system conditions change. The 2025 SB 846 report had a 0.00 LOLE in the Base Case for the year 2035.[71] Since it did not have an extended import constraint, it appears that the change in import assumptions has an impact on the 0.02 LOLE in the 2036 case here.

Although 2036 has minimal reliability risk, the shifting nature of system reliability can be seen in Figure 11 below. The figure shows the distribution of unserved energy for every hour of each month in the year 2036 when DCPP is not extended as well as the Expected Unserved Energy. Shortfalls occur only in winter months, mostly during peak winter load hours in early mornings when batteries are depleted overnight. Over the longer-term, this indicates increased winter risk, particularly if there is a lack of firm resources.

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71 Yee Yang, Chie Hong, and Brendan Burns (CPUC). April 2025. *Joint Agency Reliability Planning Assessment*. California Energy Commission. Publication Number: CEC-200-2025-004. https://efiling.energy.ca.gov/GetDocument.aspx?tn=265662&DocumentContentId=102509.

Figure 11: 2036 + Planned Retirement of DCPP Scenario

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00
7	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.35
8	0.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Source: CEC staff

The minimal nature of the reliability risk is likely due to the assumption of the full achievement of the PSP's planned resource buildout even if the California ISO import limit is imposed throughout the year. In the *2025 Fourth Quarterly Joint Agency Reliability Planning Assessment*, California's reliability was evaluated with a 40 percent reduction in future resource additions assumed in the PSP to assess whether the system can maintain reliability if procurement delays or project cancellations occur.[72] Even under this reduced buildout scenario, that assessment found minimal system reliability risk until 2035.

Discussion

The results from this analysis are presented in Table 21.

Table 21: Loss of Load Expectation (Days/Year) Across Scenarios and Sensitivities

Scenario	2031	2036
Base Case, Planned Retirement of DCPP	0.00	0.02

Source: CEC staff

With the full PSP buildout and California ISO import limits extended throughout the year, California continues to meet its LOLE criterion of 0.1 days/year throughout the study horizon.

The 2031 and 2036 study years appear to be resource adequate. With the planned retirement of the DCPP, the system sees more reliability risk starting in 2036. Accordingly, the 2036 system is dependent upon the procurement of the PSP resources to offset retirements. The results indicate that the probability of resource shortfalls is very low provided that the PSP additions are brought online as planned in addition to maintaining normal hydro and transmission conditions.

72 Ibid.

Although this analysis indicates that there is minimal reliability risk concerning the retirement of the nuclear plant itself, the emerging picture of winter reliability risk has shown that future efforts may be needed to better evaluate and address this risk.

It is fundamental to electricity system planning that planned resource portfolios meet the 0.1 days/year LOLE criterion. The primary reliability risks arise when things don't go as planned: demand will be higher than expected, imports will be lower than expected, or resources will not come online as expected. CEC staff analysis suggests that the grid will be reliable even if California ISO imports are limited beyond summer for the next few years. Provided that PSP resource additions come online as expected, the reliability risk is mitigated without DCPP through the mid-2030s.

Future Work

While this analysis provides an evaluation of reliability risks for California, it is not exhaustive. The CEC intends to continue evaluating the current and future power system to better understand and quantify potential reliability risk in the state. Future work is intended to improve system modeling and CEC's quantitative rigor and help inform policy decisions related to resource procurement, retirements, demand-side management programs, and interregional coordination. Potential topics to be addressed in future work are discussed below.

Emerging Winter Reliability Risks for California

California's energy system is on a trajectory of significant transformation. By 2040, California is projected to transition into a winter peak demand region due to widespread heat pump adoption and electrification. Even before California becomes a winter peaking system, this analysis shows that reliability risks will increasingly manifest in the winter season. This can be due to the seasonal availability of renewable resources and the potential for fuel supply disruptions. This winter risk is already observed in other parts of the WECC, such as the Pacific Northwest, portions of the Rocky Mountains, and Western Canada. Additionally, other regions in WECC – even those in warmer climates - are on a similar trajectory due to changes in resource mixes and electrification patterns.

The urgency of addressing winter reliability risks will evolve over time, based on the expected demand forecasts:

- Short Term (Next 5-7 years): Winter risks are expected to remain low but should be monitored as electrification accelerates and resource mixes change.
- Medium Term (7-15 years from today): A more detailed evaluation of winter reliability risks is warranted as California's energy system approaches a transitional phase. Planning for this period should begin today to allow for sufficient testing, validation, and resource planning efforts to adapt to the changing risk profile.
- Long Term (15+ years): California is likely to become predominantly winter risk focused. Comprehensive planning efforts should be in place to address this new paradigm.

Weather-Dependent Loads and Heat Pump Performance

The transition to winter reliability risk necessitates a deeper understanding of weather-dependent load patterns, particularly the performance of heat pumps during extreme cold events. Heat pump efficiency can degrade under extreme temperatures, leading to higher electricity consumption and amplifying peak demand. Additional effort is required to refine load profiles that reflect these dynamics, especially under prolonged cold spells.

Addressing Fuel Supply Disruptions

Fuel supply disruptions pose a compounding risk to California's winter reliability, particularly as natural gas continues to support reliability. Disruptions to gas pipelines or storage facilities during extreme cold events can curtail the availability of critical dispatchable generation. Incorporating fuel supply risk scenarios into planning models will help stakeholders better understand the potential magnitude of this threat and identify mitigation strategies. This includes diversifying winter energy sources and enhancing grid flexibility to respond to unanticipated resource shortfalls.

Weak Grid Stability Risks

The PSP resource build includes a large amount of clean energy resources such as wind, solar, and battery storage. However, an increased reliance on inverter-based resources such as these has the potential to lead to weak grid stability risks and low transmission strength with the retirement of spinning machinery such as thermal and nuclear power plants. An assessment of the transmission grid can enable planning for this potential reliability risk given operating conditions and future resource mix.

Drought Conditions and Wildfire Risks

The results presented in this analysis assume normal hydro conditions and do not assess potential impacts of wildfires, including both loss of transmission and reduced solar production from smoke. Potential drought conditions and impacts of climate change will need to be better assessed in future studies to help prepare the state, and its power system, for potential challenges.

Chapter 9: Recommendations

2026 Updated Recommendations

- The CPUC, CEC, California ISO, and GO-Biz should continue to monitor new clean energy project development to identify potential delays of projects that are critical to reliability and coordinate with stakeholders (for example, developers, local permitting authorities, federal agencies) to support timely deployment.
- The CPUC, CEC, California ISO and GO-Biz should continue to support actions identified in Executive Order N-33-25 in order to maximize the expiring federal production and incentive tax credits.
- The CEC, CPUC and California ISO should continue to monitor risks to electric reliability and maintain preparations and resources to support the grid during extreme conditions.

Chapter 10: Conclusion

Conclusion

The grid is expected to maintain system reliability with a preliminary projection of a surplus of resources in summer 2026. New resources are expected to come online through the end of 2025 and into early 2026, which will help bolster supply margins. Pending any extraordinary or extreme events, the outlook is cautiously optimistic.

Preliminary 2026 Summer Outlook

The following are key takeaways for the Preliminary 2026 Summer Outlook:

- 2026 Stack Analysis Results: The preliminary 2026 stack analysis projects a surplus of more than 4,100 MW under average conditions, 2,000 MW under a 2020 equivalent event, and more than 300 MW under a 2022 equivalent event. In the worst-case scenario, combining a 2022-equivalent event with wildfires that disrupt transmission lines, the analysis indicates a contingency need exceeding 3,400 MW.
- CED Forecast: In summer 2026, California's energy demand is forecasted to increase by about 600 MWs. The 2024 *IEPR Update* forecasts a coincident peak of more than 46,750 MW for the California ISO in summer 2026.
- California's resource portfolio continues to expand. A conservative estimate projects over 1,900 MW nameplate capacity of new resources coming online before September 2026, with the majority of additions from battery storage and solar photovoltaics. This number is expected to increase as projects that missed their original 2025 commercial operation dates receive updated timelines. These additions will further strengthen grid reliability heading into summer 2026.
- Assuming the 2023 PSP is built, California is expected to have minimal reliability risk based on a traditional resource adequacy analysis through 2026, assuming normal hydro conditions and no transmission emergencies.

APPENDIX A: Acronyms and Abbreviations

BA – balancing authority

BAA – balancing authority area

BANC – Balancing Authority of Northern California

California ISO – California Independent System Operator

CEC – California Energy Commission

CED – California Energy Demand

CERRO – California Resource and Reliability Outlook

CESER - Cybersecurity, Energy Security, and Emergency Response

COD – commercial operation date

COI – California-Oregon Intertie

CPUC – California Public Utilities Commission

D. – Decision

DAWG – Demand Analysis Working Group

DCPP – Diablo Canyon Power Plant

DEBA - Distributed Electricity Backup Assets Program

DOE - Department of Energy

DSGS – Demand Sid Grid Support Program

DR – demand response

DWR - Department of Water Resources

EEA - Energy Emergency Alert

EIA – Energy Information Administration

ESSRRP - Electricity Supply Strategic Reliability Reserve Program

GHG – greenhouse gas

GO-Biz – Governor's Office of Business and Economic Development

GW – gigawatts

GWh – gigawatt-hours

HR – House of Representatives

IEPR – Integrated Energy Policy Report

IOU – investor-owned utility

IRP – integrated resource plan

kV - kilovolt

LADWP – Los Angeles Department of Water and Power

LCR – Local capacity requirements

LCT – Local capacity technical

LDES – Long-duration energy storage

LLT – long-lead time

LOLE – Loss of Load Expectation

LSEs – load-serving entities

MMT – million metric ton

MTR – mid-term reliability

MW – megawatts

MWh - megawatt-hour

NREL - National Renewable Energy Laboratory

NQC – net qualifying capacity

OASIS – Open Access Same-time Information System

OTC – Once-through cooling

PG&E – Pacific Gas and Electric

POU – publicly owned utility

PRM – planning reserve margin

PSP – Preferred System Plan

PST – Pacific Standard Time

QFER – Quarterly Fuel and Energy Report

R. – Rulemaking

RA – resource adequacy

RCPPP - Reliable and Clean Power Procurement Program

RPS – Renewables Portfolio Standard

SB – Senate Bill

SCE – Southern California Edison

SDG&E – San Diego Gas & Electric

SOD – Slice-of-Day

SPAP – State Power Augmentation Program

SRR – Strategic Reliability Reserve

TAC – Transmission Access Charge

TED – Tracking Energy Development

TPP – Transmission Planning Process

UFLPA - Uyghur Forced Labor Prevention Act

WECC - Western Electricity Coordinating Council

APPENDIX B: Glossary

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

- California Air Resources Board Glossary, available at: https://ww2.arb.ca.gov/about/glossary
- California Energy Commission Energy Glossary, available at: https://www.energy.ca.gov/resources/energy-glossary
- California Energy Commission Renewables Portfolio Standard Eligibility Guidebook, Ninth Edition Revised, available at: https://efiling.energy.ca.gov/getdocument.aspx?tn=217317
- California Independent System Operator Glossary of Terms and Acronyms, available at: http://www.caiso.com/Pages/glossary.aspx
- 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 (BA)

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 the Balancing Authority of Northern California (BANC), California ISO, Imperial Irrigation District, Turlock Irrigation District, and Los Angeles Department of Water and Power (LADWP). The California ISO is the largest of about 38 balancing authorities in the Western Interconnection, 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)

BANC is a joint powers authority consisting of the Sacramento Municipal Utility District, 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 Independent System Operator.

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. For more information, see the Energy Education Natural vs Anthropogenic Climate Change Web page.

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.

Demand Side Grid Support (DSGS) Program creates incentives for utility customers anywhere in the state to reduce load and dispatch backup generation with existing resources on an on-call basis.

Distributed Electricity Backup Assets (DEBA) Program provides incentives for the construction of clean and efficient distributed energy resources. The CEC adopted program guidelines on October 18, 2023, with basic program parameters. Funding will be issued through grant funding opportunities.

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 photovoltaic 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)

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 SB 100 Joint Agency Report.

Electricity Supply Strategic Reliability Reserve Program (ESSRRP)

ESSRRP is being implemented by the 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.

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).

Integrated Energy Policy Report (IEPR)

SB 1389 (Bowen, 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 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 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)

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 CCA. California has three large IOUs offering electricity service: Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric.

Load serving entity (LSE)

A load serving entity is defined by the California Independent System Operator 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.

Net qualifying capacity (NQC)

The amount of capacity that can be counted towards meeting Resource Adequacy 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.

Once-through cooling (OTC)

OTC 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 and the CEC Once-Through Cooling Phaseout Tracking Progress Report.

Planning reserve margin (PRM)

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 resource adequacy program increased the minimum PRM from 17 percent last year to 18 percent for 2026 and 2027 to ensure sufficient capacity under higher demand and extreme weather conditions.

Publicly owned utility (POU)

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. In contrast to IOU, all utility functions are handled by these utilities. Examples include the Los Angeles Department of Water and Power and the Sacramento Municipal Utility District. Municipal utilities serve about 27 percent of California's total electricity demand.

Renewables Portfolio Standard (RPS)

The 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.

Transmission Planning Process (TPP)

The California Independent System Operator'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 Energy Commission's annual demand forecast) to assess short- and long-term transmission infrastructure needs. For more information, see the California ISO Transmission Planning Web page.