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AGENCY**

Joint Agency Reliability Planning Assessment

SB 846 Second Quarterly Report 2026

May 2026 | CEC-200-2026-005

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ABSTRACT

The Joint Agency Reliability Planning Assessment addresses requirements for electric system reliability reporting in Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022). This report provides the 2026 second quarterly review of the supply forecast and risks to reliability in the California Independent System Operator territory, and includes an updated analysis for summer 2026.

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

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EXECUTIVE SUMMARY

Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) mandated the California Energy Commission (CEC) and California Public Utilities Commission (CPUC) to develop and provide to the Legislature quarterly joint agency reliability planning assessments beginning on or before December 15, 2022. These assessments include updates on electric system demand and supply for the next 5- and 10-year periods, as well as an assessment of electric system reliability under different risk scenarios. The assessment contained in this report is also required to provide information on the status of new resources and delays or barriers to their availability to support reliability.

This is the second quarterly report of 2026 and provides an update on electric demand and supply for summer 2026 for the California Independent System Operator balancing area. The analysis completed in this report is based on data that were available as of January 27, 2026. This report does not update the 5- and 10-year projections of system reliability or provide any recommendations to the Legislature; that assessment is done annually in the first quarterly report.

Projected system conditions for summer 2026 show improved reliability compared to the first quarter assessment. The latest resource stack analysis, which focuses on September, the month with the highest risk of shortfalls, continues to show positive supply margins under planning standard conditions. Under planning standard conditions, the installed capacity surplus is projected to be 6,635 megawatts (MW), an increase of over 2,100 MW compared to the first quarter report's 4,442 MW projection. Even under extreme heat scenarios similar to 2020 and 2022 events, the system maintains an adequate surplus with projections of 4,540 MW for a 2020 equivalent event and 2,911 MW for a 2022 equivalent event.

Despite the forecasted surplus, certain risks to grid reliability remain. Wildfires can damage transmission infrastructure, potentially reducing electricity supply by up to 4,000 MW. Additionally, delays in new resource projects could reduce available capacity. Known loads, which are additional electricity demand identified through utility planning documents but not fully captured in the baseline forecast, could add over 1,300 MW of peak demand to California's grid in 2026. If multiple risk factors occur simultaneously, such as extreme heat combined with wildfire impacts, California may need to activate emergency procedures to maintain grid reliability.

CHAPTER 1: Introduction

This report provides an update on reliability-related activities and developments since the combined *2026 Joint Agency Reliability Planning Assessment, Covering the Requirements of SB 846* (First Quarterly Report for 2026) and *SB 1020* (Annual Report)¹ was written. 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, as mandated by SB 846 .

Summer Readiness

To prepare for summer 2026, the California Independent System Operator (California ISO) will continue its practice of hosting summer readiness activities including Summer Readiness trainings and tabletop exercises with state entities, neighboring balancing authority areas (BAAs), and utilities. The California ISO will also publish its 2026 Summer Loads and Resources Assessment in the May 2026 timeframe which will evaluate expected 2026 summer supply and demand conditions for the California ISO BAA.

Demand Forecast

California’s electricity demand forecast contains multiple components developed annually as part of each Integrated Energy Policy Report (IEPR) proceeding. The Baseline Forecasts extend existing trends into the future, while Managed Forecasts are created by adding “additional achievable” load modifiers to the baseline to account for the potential impacts of policies and programs that have substantial uncertainty surrounding their implementation. These load modifiers can be arranged in various combinations, but the primary groupings are the Planning Forecast used for system-wide planning, and the Local Reliability Forecast used for local transmission and distribution planning.

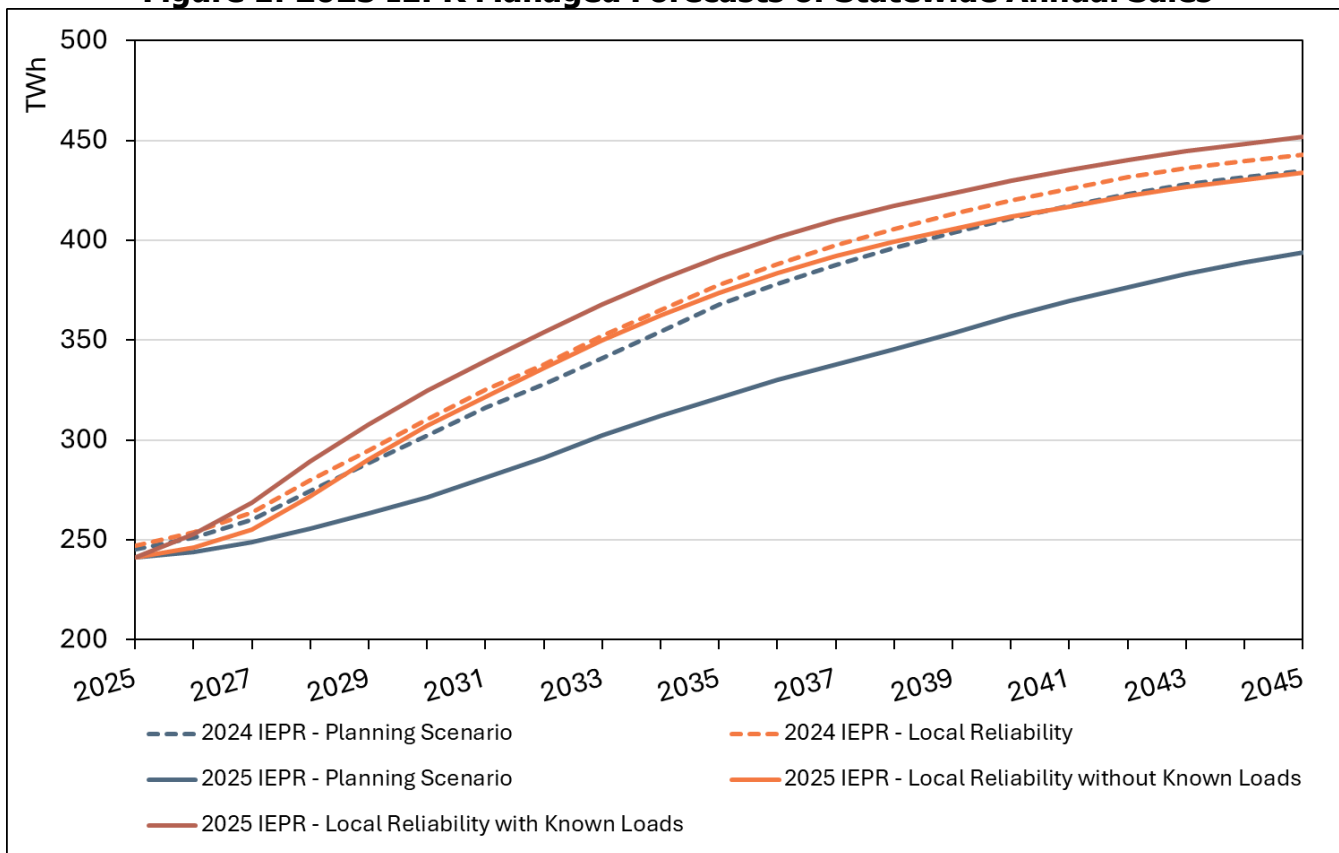
The 2025 IEPR includes a new component consisting of known loads data from utilities, which consists of customer applications to connect new loads to the utility distribution system. However, there is some uncertainty in the rate of project completion, energization timelines, utilization factor, and potential overlap with other components of the overall California Energy Demand (CED) Forecast. Due to these uncertainties, the known loads have been excluded from the Planning Forecast, and two versions of the Local Reliability Forecast have been developed, one including known loads and one excluding them. This flexibility helps to address potential gaps between distribution and transmission planning, while allowing for stability in resource procurement and infrastructure planning that is already underway.

Figure 1 shows the 2025 IEPR Managed Forecasts of annual energy sales compared to the 2024 IEPR Update Managed Forecasts. The 2025 IEPR Managed Forecasts project lower near-term growth in annual energy sales compared to the previous forecasts. This is due to

1 California Energy Commission. [2026 First Quarterly Joint Reliability Planning Assessment and SB 1020 Report](https://efiling.energy.ca.gov/GetDocument.aspx?tn=269909&DocumentContentId=107061). Available at: <https://efiling.energy.ca.gov/GetDocument.aspx?tn=269909&DocumentContentId=107061>

economic uncertainty, higher electricity rates, increased energy efficiency, and deferred adoption of both transportation and building electrification measures. These factors also cause the Planning Forecast to be substantially lower than the previous vintage over the entire forecast period. However, the Local Reliability Forecast without known loads is similar to the previous vintage and the Local Reliability Forecast with known loads is higher after 2026.

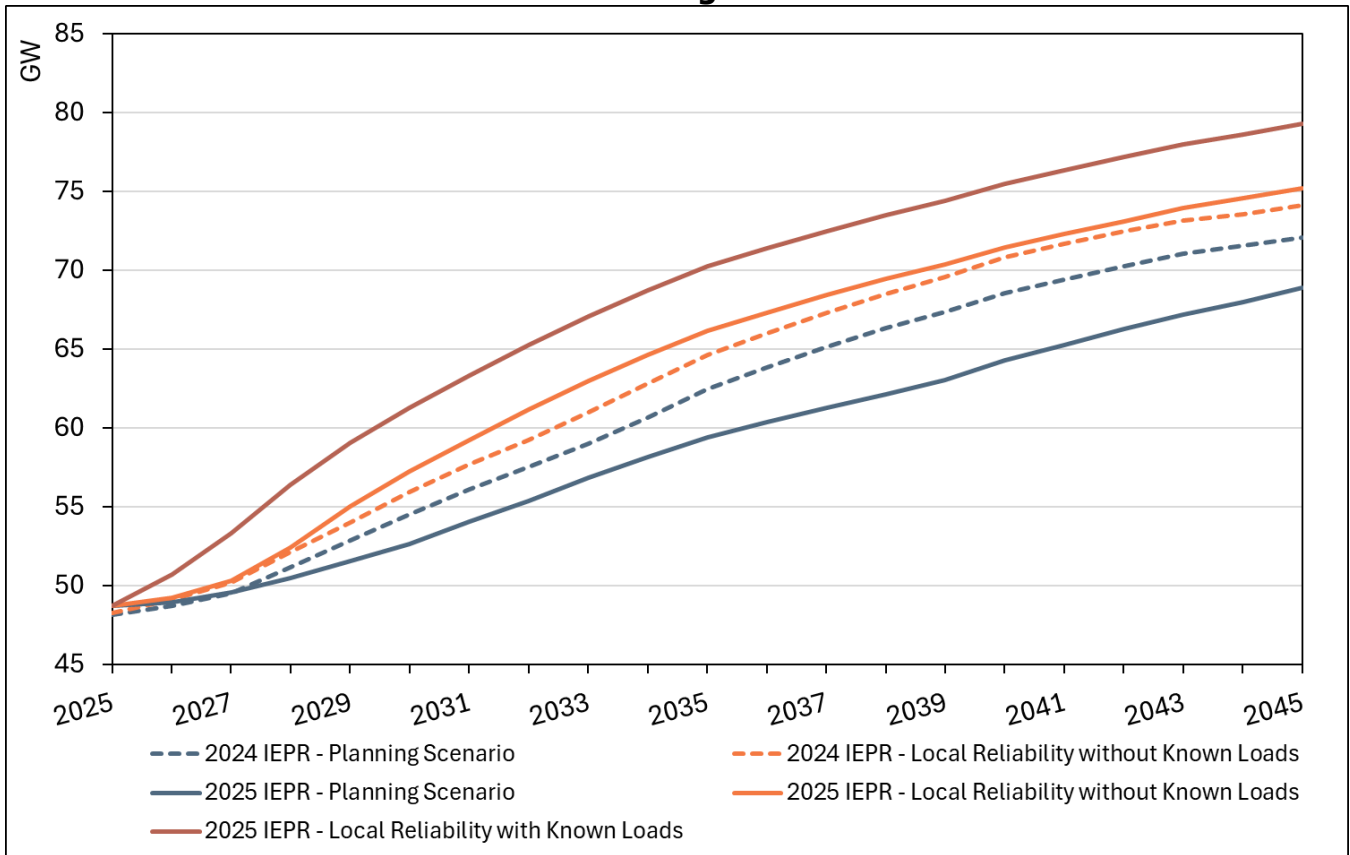
Figure 1: 2025 IEPR Managed Forecasts of Statewide Annual Sales



Source: CEC 2024 IEPR Update and 2025 IEPR Managed Sales Forecasts

Figure 2 shows the 2025 IEPR Managed Forecasts of annual peak demand for the California ISO system compared to the 2024 IEPR Update Managed Forecasts. The 2025 IEPR Managed Forecasts also project slightly lower near-term growth in peak demand compared to the previous forecast. However, for peak demand, the lower near-term growth is offset by a weather normalized estimate of 2025 peak load that is higher than previously forecast.

Figure 2: 2025 IEPR Managed Forecasts of Annual Peak Demand for the California ISO Region



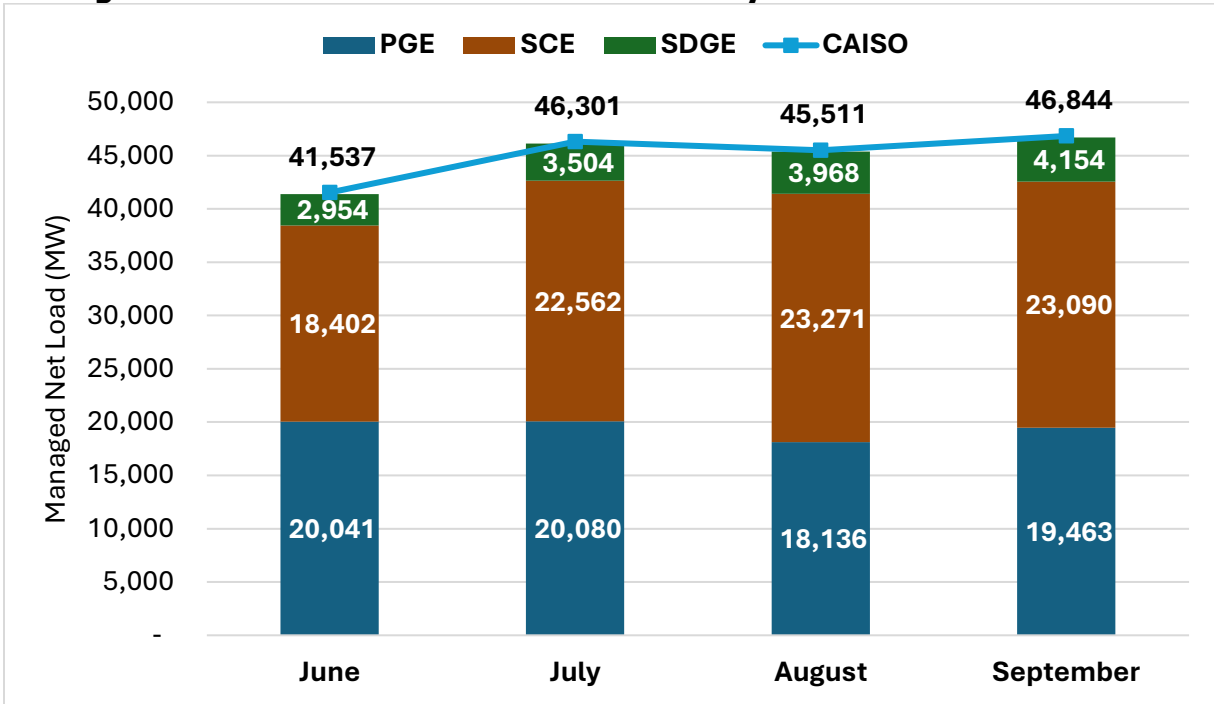
Source: CEC 2024 IEPR Update and 2025 IEPR Managed Sales Forecasts

Electricity demand typically peaks in the summer months of July, August, or early September. Figure 3 shows the coincident peak² forecasts for the summer months of 2026 for the entire California ISO territory, composed primarily of the Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) transmission access charge (TAC) areas. Note that the annual system peak³ for the California ISO territory of more than 46,800 MW is forecast to occur in September, but the July and August peaks are comparable in magnitude. The annual system peak could be reasonably expected to occur in any of these months.

² *Coincident peaks* are the amount of demand that the individual TAC areas contribute at the time of the overall California ISO system peak. *Noncoincident peaks* are the maximum peaks of each individual TAC areas, which do not necessarily occur at the same time.

³ The annual system peak is the point of highest demand experienced by the entire California ISO transmission system for a given year.

Figure 3: California ISO Coincident Monthly Peaks for Summer 2026



Source: CEC 2025 IEPR Planning Forecast

Note: The 2025 IEPR Planning Forecast does not include known loads.

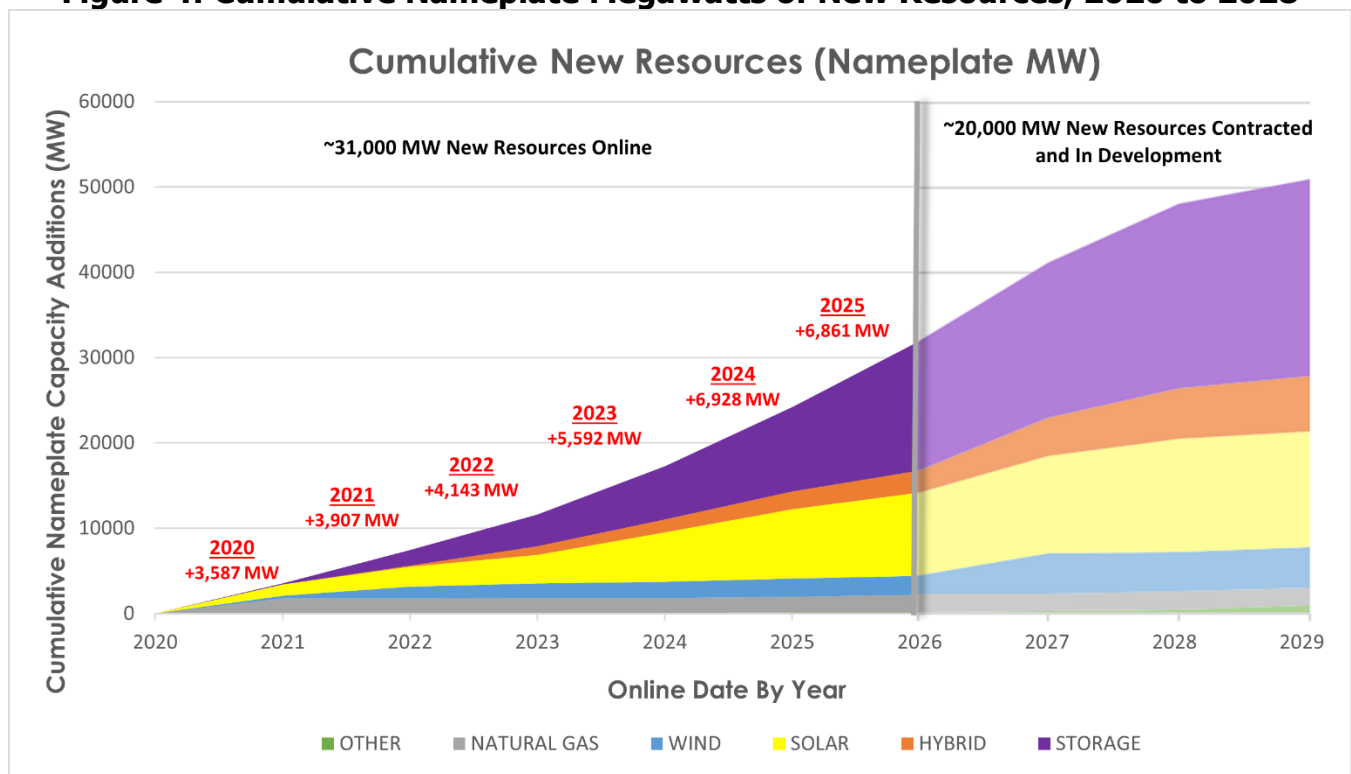
Note: SCE includes pumping load from the Metropolitan Water District of Southern California. The California ISO total also includes a small amount of load supplied by the Valley Electric Association.

CHAPTER 2: Supply Forecast

New Megawatts Online

Throughout the California ISO Balancing Area, 30,999 MW of new nameplate capacity have come online from January 2020 to December 2025. As shown in Figure 4, California continues to experience rapid growth in clean energy resources, particularly solar photovoltaics (PV) and energy storage. In 2025 alone, over 6,800 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 4: Cumulative Nameplate Megawatts of New Resources, 2020 to 2028



Source: CPUC, December 2025

Compliance with CPUC’s Procurement Orders

In July 2025, CPUC staff released the Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Mid-Term Reliability (D.21-06-035) Procurement after

analyzing the load serving entities' (LSEs') December 2024 compliance filings.⁴ 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 filings indicates LSEs subject to mid-term reliability (MTR) and Supplemental MTR procurement obligations have largely met their obligations for MTR Tranches 1 and 2 (corresponding to years 2023 and 2024).

These 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.⁵

For the 2023-2024 period, LSEs procured and brought online about 93 percent of their cumulative 8,000 MW NQC obligation. Most 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.⁶

Estimates of Planned Resources

Table 1 through Table 3 estimate cumulative expected new capacity under contract to CPUC-jurisdictional LSEs during each six-month period from now through 2029. Table 1 organizes this data by Transmission Access Charge (TAC),⁷ Table 2 by LSE type, and Table 3 by resource type. The tables include resources being developed for compliance with IRP procurement orders as well as procurement for LSE compliance with Renewables Portfolio Standard and procurement the CPUC approved in the Emergency Reliability proceeding. All totals provided

4 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). Available at <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>.

5 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. D.25-09-007 removed the option for LSEs to use bridge contracts as a method for compliance, with the exception of contracts that were entered into prior to the adoption of D.25-09-007.

6 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). Available at <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>.

7 A Transmission Charge Access area is a designated geographical region where a single Participating Transmission Operator - an entity that manages transmission infrastructure - operates. Major examples of PTOs with their own TAC areas include, but are not limited to: PG&E, SCE, and SDG&E.

below represent the cumulative LSE-reported September NQC under contract to CPUC-jurisdictional LSEs.⁸

LSE procurement activity is ongoing to meet existing CPUC IRP procurement orders. Table 1 through Table 3 do not include all known resources in development in California, nor is all of this procurement in the California ISO’s footprint. In addition, Table 1the tables represent only resources known to be under contract to CPUC-jurisdictional LSEs between 2026 and 2029, as of December 2025.⁹ The new supply resources are measured in September NQC, a measure of a resource’s maximum capacity eligible to be counted towards the CPUC’s resource adequacy (RA) requirements adjusted to the deliverable capacity value.

Table 1: Cumulative Estimated September NQC (MW) by Transmission Access Charge (TAC) Area 2026 through 2029

TAC Area	2026 Q1-Q2	2026 Q3-Q4	2027 Q1-Q2	2027 Q3-Q4	2028 Q1-Q2	2028 Q3-Q4	2029 Q1-Q2	2029 Q3-Q4
East Central	908	1,784	3,228	3,609	4,987	5,008	5,148	5,736
North	586	846	1,853	2,298	2,609	2,865	2,939	2,939
South	482	546	669	743	743	743	743	743
Other	982	1,937	2,506	3,746	4,220	4,220	4,247	4,247
Total	2,958	5,112	8,256	10,397	12,558	12,835	13,076	13,665

Source: CPUC Staff Aggregation of December 2025 LSEs’ Procurement Status Reports

Table 2: Cumulative Estimated September NQC (MW) by LSE Type, 2026 through 2029

LSE Type	2026 Q1-Q2	2026 Q3-Q4	2027 Q1-Q2	2027 Q3-Q4	2028 Q1-Q2	2028 Q3-Q4	2029 Q1-Q2	2029 Q3-Q4
IOU	1,172	2,392	3,396	4,996	5,957	5,957	5,957	6,190
Non-IOU	1,785	2,720	4,860	5,401	6,602	6,879	7,119	7,474
Total	2,958	5,112	8,256	10,397	12,558	12,835	13,076	13,665

Source: CPUC Staff Aggregation of December 2025 LSEs’ Procurement Status Reports

8 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.

9 These totals are subject to change as the CPUC receives new data from LSEs, conducts field calls with developers and investor-owned utilities’ (IOU’s) interconnection departments, and continues to evaluate the data.

Table 3: Cumulative Estimated September NQC (MW) by Resource Type, 2026 through 2029

Resource Type	2026 Q1-Q2	2026 Q3-Q4	2027 Q1-Q2	2027 Q3-Q4	2028 Q1-Q2	2028 Q3-Q4	2029 Q1-Q2	2029 Q3-Q4
Solar	100	546	725	1,493	1,493	1,493	1,493	1,727
Battery	1,778	2,671	4,630	5,827	7,238	7,352	7,492	7,847
Paired / Hybrid	784	1,127	2,004	2,139	2,420	2,471	2,545	2,545
Wind	274	650	650	650	650	730	730	730
Geo-thermal	22	112	241	282	752	784	811	811
Biomass / Biogas	-	6	6	6	6	6	6	6
Total	2,958	5,112	8,256	10,397	12,558	12,835	13,076	13,665

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

CHAPTER 3: Reliability Developments at CPUC

Efforts to ensure future system reliability continue across CPUC regulatory proceedings. Three noteworthy developments occurred recently or are projected for the next quarter which are described below.

Recommended 2026-27 Transmission Planning Process Portfolios

Every year, CPUC staff develop a recommended set of portfolios for the California ISO to use in its annual Transmission Planning Process (TPP). Generally, in each TPP cycle, the California ISO evaluates a reliability and/or policy-driven base case portfolio. On February 26, the CPUC adopted base and sensitivity cases for the 2026-27 TPP cycle. (D.26-02-057)

The California ISO's TPP base case analysis generally leads directly to transmission project approval that can help resources meet future system needs. The 2026-2027 base case is designed to have similar policy assumptions as the 2025-26 TPP base case. For the proposed base case portfolio, CPUC staff studied a case that reflects a partial buildout of the maximum procurement volumes considered in CPUC's need determination analysis pursuant to D.24-08-064, related to Assembly Bill 1373 (Garcia, Chapter 367, Statutes of 2023).

Along with the base case analysis, in each TPP cycle the California ISO can typically analyze one or more sensitivity portfolios. The CPUC transmitted one sensitivity portfolio to the California ISO focused on a limited wind deployment future. The sensitivity represents a future with reduced in-state and out-of-state wind procurement, and without offshore wind. CPUC staff developed the sensitivity case to reflect the recent lack of wind development in California, and the current changes in federal policy toward wind projects. The sensitivity case will provide insights into transmission implications and resources that will be needed to replace wind in the recommended base case portfolio and recently adopted TPP portfolios if its development were significantly limited.

Proposal of New CPUC Procurement Order

Also included in the February 2026 Decision is an order for additional procurement from LSEs. The order calls for 2,000 MW of reliability capacity, due online by June in 2030, 2031, and 2032, for a total of 6,000 MW of new incremental reliability capacity for the California ISO balancing area. These amounts are derived from CPUC staff analysis, using the 2024 IEPR CED Forecast, which found that the volumes of expected resources available from 2029 to 2032 would be insufficient to meet the reliability standard.¹⁰ Two rounds of stakeholder public comments in October 2025 and February 2026 also informed the details of the order in the Decision. Under the order, LSEs can count "excess" procurement (beyond the minimum required to comply with the previous procurement orders) toward their assigned obligations

¹⁰ This assessment differs from prior CEC analyses in previous SB 846 reports; it only assumes new resources come online based on whether they are contracted, subject to adjustments, while the CEC analyses assumed all resources in the 2023 PSP would be contracted, developed, and interconnected on the timeline of the PSP.

and LSEs' respective procurement would be accounted for in a potential successor procurement program that is currently being developed with stakeholders. Additionally, 1,500 MW of the total 6,000 MW must come from either energy storage of at least eight-hour duration or from clean-firm generation resources.

Release of CPUC IRP Filing Requirements for LSEs

All LSEs subject to the CPUC's IRP process are required to file and serve their individual IRPs with the CPUC. On January 16, 2026, CPUC staff posted Filing Requirements documents -- the Narrative Template, the Resource Data Template, and the Clean Power System Calculator -- on the CPUC website to assist individual LSEs in preparing their individual IRPs for Commission review. These materials are the final products from the two models (RESOLVE and SERVM) that CPUC uses to assess future electric system needs and performance for reliability, cost, and emissions reduction.

CHAPTER 4: Tracking Project Development

The Tracking Energy Development (TED) Task Force, comprised of the CEC, CPUC, Governor’s Office of Business Development (GO-Biz) and California ISO, continues to track energy projects under development and helps to navigate challenges and barriers where appropriate.

In 2025, the TED Task Force tracked about 200 energy projects under development in California through regular check-in meetings with developers to review near-term project status. Additional ad-hoc meetings were scheduled to review specific project challenges and, when applicable, for the TED Task Force to coordinate actions across member agencies. The TED Task Force had more than 250 meetings with stakeholders regarding energy generation projects that included developers, LSEs, permitting entities, associations and local and federal government agencies. Table 4 lists the TED Task Force tracking efforts and its frequency.

Table 4: Resource Tracking Efforts

Frequency	Action
Ongoing	TED Task Force conducts outreach to developers with projects under development to review status of projects and issues, if any.
Ongoing	Ad-hoc meetings with developers and others about specific project challenges.
Weekly	TED Task Force meets weekly to review issues/developer requests for assistance and provide updates.
Monthly	CPUC receives and compiles data from LSEs on resources under contract for the near-term.
Monthly	CPUC compiles data on new MW that have come online.
Monthly	CPUC holds calls with IOU interconnection teams to review projects, pinpoint discrepancies, and identify operational areas for improvement.
Quarterly	TED Task Force provides progress update to SB 846 Joint Agency Reliability Reports.
Biannual	California ISO, in conjunction with CPUC, hosts the Transmission Development Forum to discuss delays to transmission projects including network upgrades.

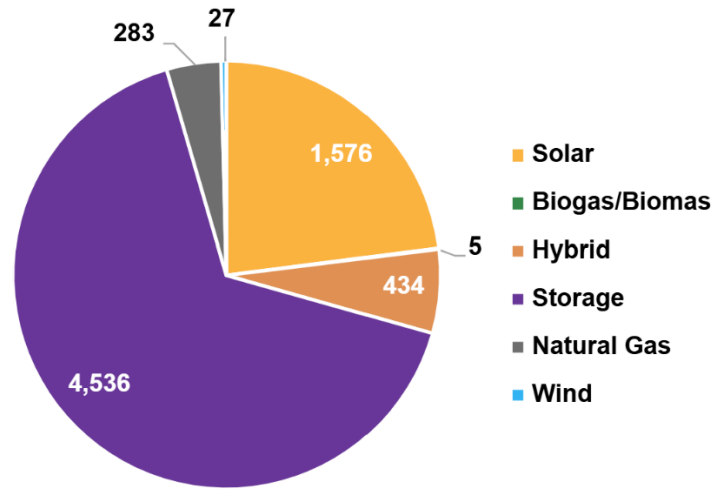
Source: GO-Biz

Energy Projects Deployed in 2025

New projects continue to come online and are providing power to millions of Californians. There were 103 projects totaling 6,867 MW of nameplate capacity that came online in 2025. Figure 5 shows the total MWs added to the grid by resource type and Figure 6 shows a map and list of the top 10 counties by MW where these projects were deployed. Additional

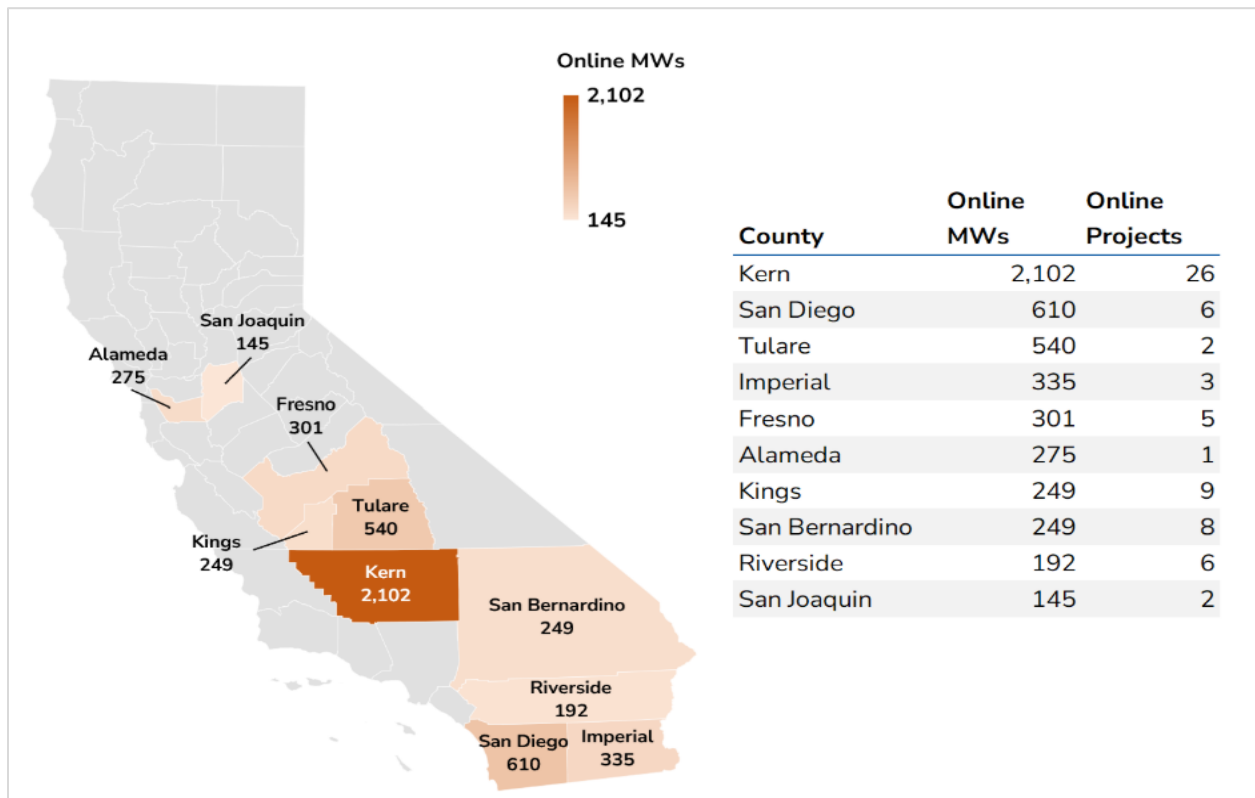
information on energy projects online and operating can be found on the state’s infrastructure website.¹¹

Figure 5: 2025 Megawatts (MWs) Deployed by Resource Type



Source: GO-Biz

Figure 6: 2025 Top 10 Counties by MWs Deployed



¹¹ [Building California](https://build.ca.gov/). Available at <https://build.ca.gov/>.

Source: GO-Biz

New resources span a range of technology types. Table 5 summarizes nameplate capacity and projects added in 2025, by technology.¹²

Table 5: 2025 Cumulative New Resource Additions

Technology Type	Nameplate Capacity (MW)	Estimated Sept. NQC (MW)*	Number of Projects
Storage	4,536	3,325	50
Solar	1,426	142	32
Hybrid (Storage/Solar)	399	316	6
Wind	27	6	1
Geothermal	-	-	-
Biomass, Biogas	5	-	2
Subtotal, New SB 100 Resources, California ISO	6,393	3,788	91
Natural Gas Capacity Additions**	13	11	4
Total New Resources, California ISO	6,405	3,800	95
New Imports, Pseudo-Tie or Dynamically Scheduled	455	58	8
Total New Resources, including Imports	6,861	3,858	103

Source: California ISO Master Control Area Generating Capability Lists and CPUC NQC Lists, January 1, 2024, to December 31, 2025

* Some new projects have not yet made it onto the CPUC NQC Lists and have not yet been assigned NQC. Future reports will include updated NQC amounts for these resources.

¹² Each figure in Table 5 is rounded up to the nearest MW; consequently, the values in the "Subtotal" and "Total" rows may diverge slightly from the sum of the values directly above them.

** MW in this row come from increases in the maximum power output of existing units, not entirely new resources.

Renewable Energy Project Development Challenges in 2025

Despite the impressive increase in new capacity that came online in 2025, challenges remain in achieving the scale and diversity of resources necessary for the clean energy transition. Renewable energy project deployment continues to face many of the same challenges as previously reported. These challenges include transmission supply chain shortages for critical equipment, interconnection delays due to physical interconnection work, and permitting and siting approval delays.

With the passage of The One Big Beautiful Bill Act, H.R. 1 (119th Cong. 2025, Pub. L. No. 119-21), federal production and investment tax credits are no longer available for solar and wind projects after December 31, 2027. Specifically, solar and wind projects must be in construction by July 4, 2026, or placed in service by December 31, 2027, to claim these tax credits. The tax credits help to drive investment, keep electricity prices affordable, spur innovation and create jobs. Elimination of these tax credits negatively impacts hundreds of projects under development in California.

In response to acceleration of the phase out of federal tax credits for solar and wind projects, Governor Newsom issued EO N-33-25, directing the Energy Working Group of the Infrastructure Strike Team and relevant state agencies to take necessary actions to assist eligible projects in capturing the expiring tax credits.

The Energy Working Group worked quickly to identify the eligible projects and held a state-developer convening on October 24, 2025, to discuss barriers to clean energy project deployment and potential solutions. Developers provided an overview of project development timelines, presented on challenges, pain points and frequent bottlenecks that occur, and shared ideas for solutions to address the issues. State agencies, particularly those with permitting authority over projects, were able to hear concerns and shared best practices for engagement and application submittals. The Energy Working Group, through the TED Task Force will continue to gather insights regarding federal tax credit project updates and coordinate actions to support utilization of available federal tax credits before they expire.

On November 21, 2025, CPUC President Alice Reynolds sent a letter requesting that PG&E, SCE, and SDG&E renew their efforts to improve transmission and interconnection. The letters requested that each of the utilities submit a report to the CPUC describing the actions they were taking to expedite interconnection of new resources in 2025 and 2026 and identify process improvements for the transmission and interconnection build out in 2026 and the coming years. The utilities were asked to also identify whether any actions would interfere with these efforts to reduce costs for ratepayers. These 2025 letters are a follow-up to March 2022 letters President Reynolds sent to the same IOUs, which culminated in utility interconnection process improvements and better availability of data for stakeholders.

CHAPTER 5: Reliability Assessment

The reliability assessment approach used for this report is consistent with the Near-Term Reliability Assessment published by the CEC in the *First Quarterly Report for 2026 and SB 1020 Annual Report*. This assessment is based on installed capacity rather than Resource Adequacy showings. The assessment compares an hourly projection of anticipated supply, against the projected hourly demand plus the reserve margin, for the peak day of each month (July through September). An 18 percent planning reserve margin (current CPUC resource adequacy planning standard) represents average conditions, while 22.5 and 26 percent planning reserve margins are comparable to elevated conditions experienced during the 2020 and 2022 heat events, respectively.

The resource stack analysis continues to conservatively identify the maximum hourly contingency need for summer 2026 under various planning reserve margin scenarios. There is no projected need for contingency resources in July and August. As a result, this section focuses on September, which typically presents the greatest reliability challenges during the summer months.

California ISO Area: Updated Resource Stack Analysis Results for Summer 2026

This stack analysis continues to focus on Hour 18 of September, a period of high demand coupled with lower supply, making it the most critical time for evaluating potential shortfalls. Several changes have been made to the resource stack since the release of the *First Quarterly Report for 2026 and SB 1020 Annual Report*.

Existing Resources

Existing resources refer to the amount of firm or dispatchable energy capacity currently available on the grid. Once-through cooling (OTC) resources are excluded from this category and instead accounted for as part of the contingency resource pool. Intermittent resources such as solar and wind generation are also excluded from existing resources, but are incorporated separately in the stack analysis using hourly generation profiles that reflect their expected output.

The most notable update in the stack is the addition of over 2,200 MW to existing resources since the last report. This increase is primarily due to updates in the 2026 NQC list, which was expected to be refined at the beginning of 2026, as noted in the last report. The increase also reflects projects that were previously excluded from the resource stack because they had not demonstrated sufficient progress toward commercial operation but that have since come online. The analysis in this report uses data from January 12, 2026, which reflects more accurate capacity values for existing resources.

Resource Adequacy Imports

Resource adequacy (RA) imports are electricity supplies from out-of-state generators contracted to provide firm capacity to California. In this analysis, imports have increased by

over 300 MW since the last report, bringing the total to over 5,800 MW. This increase is driven by the SunZia wind project in New Mexico, which was previously categorized as a new resource but has been reclassified as an RA import to reflect its out-of-state location. SunZia is expected to come online in May 2026. For this resource stack analysis, SunZia will be projected to contribute over 300 MW to import capacity after applying an out-of-state wind generation profile to the project's nameplate capacity at Hour 18 of September. This is an initial estimate based on the project's expected online date and capacity from the California ISO's interconnection queue.

Expected New Resources

New resources refer to the sum of expected new in-state generation capacity projected to come online by June 30, 2026, adjusted for hourly generation profiles for resources such as solar, wind, and batteries. This analysis continues to apply a conservative approach to counting new resources. Given the uncertainty associated with new project development, only resources that show clear progress toward commercial operation are included. These include resources in testing or partially online status, active projects with assigned qualifying capacity, and resources that have begun operating but are not yet reflected in resource adequacy accounting. This analysis uses data from the California ISO's interconnection queue as of January 27, 2026.

Total expected new resources are 897 MW, a net decrease of approximately 153 MW since the last report. This decrease is primarily due to the reclassification of the SunZia project to RA imports, as discussed above. Batteries account for the majority of expected new resources, making up 83 percent of new capacity in the stack analysis.

Forecasted Demand

As stated earlier, the 2025 IEPR developed two different demand forecasts: one without known loads, which serves as the baseline forecast, and one with known loads. The stack analysis in this report uses both demand forecasts to assess the potential impacts of additional demand on system reliability. The demand value is based on the newly adopted 2025 CED Forecast.¹³

For the baseline analysis, the updated projected peak demand for September 2026 has been revised downward by 112 MW since the last report, bringing it to 46,546 MW. With the known loads added to the analysis, the system is projected to have over 1,300 MW of additional electricity demand in September, bringing the projected peak demand to 47,909 MW. This additional demand would reduce available supply margins across all scenarios.

Stack Analysis Results

The baseline stack analysis in this report shows a positive supply margin for summer 2026 of 6,635 MW under planning standard conditions, 4,540 MW for a 2020 equivalent event, and 2,911 MW for a 2022 equivalent event. These surpluses represent a significant improvement

¹³ [2025 Integrated Energy Policy Report](https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2025-integrated-energy-policy-report-0). California Energy Commission. Available at <https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2025-integrated-energy-policy-report-0>.

compared to the *First Quarterly Report for 2026 and SB 1020 Annual Report*, with an increase of over 2,190 MW under all scenarios. The improvement is driven by the increase in existing resources, imports from the SunZia project, and a modest reduction in forecasted peak demand.

Table 6: Comparison of Summer Assessment Results for September 2026 – Hour 18

	2026 1st Quarter Report (MW)	2026 2nd Quarter Report (MW)	Change Since Last Update (MW)
Supply			
Existing Resources	48,746	50,988	▲ 2,242
Solar	1,771	1,766	▼ 5
Wind	1,307	1,307	0
RA Imports	5,500	5,807	▲ 307
Demand Response	794	794	0
Expected New Resources	1,050	897	▼ 153
Total (MW)	59,168	61,559	▲ 2,391
Demand			
Sept. Peak Demand	46,658	46,546	▼ 112
Surplus/Shortfalls			
Planning Standard	4,442	6,635	▲ 2,193
2020 Equivalent Event	2,342	4,540	▲ 2,198
2022 Equivalent Event	708	2,911	▲ 2,203

Source: CEC staff with California ISO data

Stack Analysis Results with Known Loads

Table 7 shows the impact of known loads on system reliability across different scenarios. If these known loads materialize as expected, the available supply margin would decrease from 6,635 MW to 5,437 MW under planning standard conditions, from 4,540 MW to 3,281 MW under a 2020 equivalent extreme heat event, and from 2,911 MW to 1,604 MW under extreme heat similar to the 2022 event.

Table 7: Impact of Known Loads on Reliability

Scenario	Baseline Demand (MW)	Known Loads (MW)	Demand with Known Loads (MW)	Supply Margin with Known Loads (MW)	Changes in Supply Margin (MW)
Planning Standard	54,924	▲ 1,609	56,533	5,437	▼ 1,198
2020 Equivalent Event	57,019	▲ 1,670	58,689	3,281	▼ 1,259
2022 Equivalent Event	58,648	▲ 1,718	60,366	1,604	▼ 1,307

Source: CEC staff

Risk Scenarios

The current analysis shows that the grid will have enough power to meet demand this summer under the evaluated scenarios. However, several factors could reduce the available supply margin. This section examines two key risks: delays in new supply resources coming online and wildfires affecting transmission lines.

Delays in New Projects

The stack analysis includes 897 MW of new resources expected to be available by summer 2026. These projects are currently being tested or are close to completion. However, new projects can be delayed due to equipment shortages, permitting issues, or interconnection problems.

Table 8 shows the impact of project delays under a 2022 equivalent heat event. If 40 percent of new projects are delayed, the system would lose up to 359 MW of new resource capacity. However, the system has sufficient existing supply to absorb the impact of delayed new resources. Even if all currently forecasted new resources are delayed, the grid would still maintain positive supply margins under this extreme heat scenario, assuming no other coincident events.

Table 8: Impact of New Project Delays – 2022 Equivalent Heat Event

Delay Scenario	Expected New Resources (MW)	Delayed Capacity Difference (MW)	Supply Margin Result (MW)
No Delays	897	0	2,911
20% of New Projects Delayed	897	▼ 179	2,732
40% of New Projects Delayed	897	▼ 359	2,552

Source: CEC staff

Wildfire Impact

Wildfire remains a major source of uncertainty, with the potential to reduce available capacity primarily through impacts on major transmission lines. For example, the 2021 Bootleg Fire caused the loss of 4,000 MW of import capability on the California-Oregon Intertie (COI).

Modeling results from a similar transmission outage scenario show that under typical conditions, the system would remain reliable. However, if a wildfire related outage were to occur during extreme heat, California could face reliability challenges. Table 9 and Table 10 shows the combined impact of potential wildfires and extreme heat conditions. Table 9 presents results against the baseline forecast, while Table 10 incorporates Known Loads demand projections. If a transmission outage coincides with a 2022 equivalent heat event, the baseline analysis indicates a potential contingency need exceeding 1,000 MW. When Known Loads demand is included, there may be a contingency need of over 700 MW in a 2020 equivalent heat event, and over 2,350 MW under a 2022 equivalent heat event.

Table 9: Impact of Wildfire Transmission Outages on Reliability – Baseline Analysis

System Condition	Baseline Forecasted Surplus/Shortfall (MW)	Loss of Transmission (MW)	Supply Margin Result (MW)
Planning Standard	6,635	▼4,000	2,635
2020 Equivalent Event	4,540	▼4,000	540
2022 Equivalent Event	2,911	▼4,000	-1,089

Source: CEC staff

Table 10: Impact of Wildfire Transmission Outages on Reliability with Known Loads

System Condition	Forecasted Surplus/Shortfall with Known Loads(MW)	Loss of Transmission (MW)	Supply Margin Result (MW)
Planning Standard	5,437	▼4,000	1,437
2020 Equivalent Event	3,281	▼4,000	-719
2022 Equivalent Event	1,604	▼4,000	-2,396

Source: CEC staff

Contingency Resources

The agencies and the California ISO continue to track contingency resources, which are resources outside of the resources considered in the stack analysis and provide support during extreme events. The updated contingency list for 2026 identified in Table 11 is expected to

provide between 4,300 MW and 4,400 MW during extreme events and may be called upon to cover contingency needs identified in real time grid operations.

Table 11: Contingency Resources for Summer 2026

Type	Contingency Resource	Available MW July	Available MW August	Available MW September
SRR, SPAP ¹⁴	DWR Electricity Supply Strategic Reliability Reserve Program and State Power Augmentation Program ¹⁵	3,079	3,079	3,079
SRR	Demand Side Grid Support (DSGS) ¹⁶	360	360	360
SRR	Distributed Electricity Backup Assets (DEBA) (under development)	0	0	0
CPUC	Ratepayer Programs (Emergency Load Reduction Program, Smart Thermostats, etc.)	128	124	123
CPUC	Imports Beyond Stack	0	0	0
CPUC	Capacity at Co-gen or Gas Units Above Resource Adequacy	599	599	499
Non-Program	Balancing Authority Emergency Transfers	300	300	300
Non-Program	Thermal Resources Beyond Limits: Gen Limits Needing 202c ¹⁷	25	25	25
	Total	4,466	4,462	4,361

Source: CEC staff with California ISO, DWR, and CPUC data

14 Strategic Reliability Reserve and State Power Augmentation Program, MW amounts reflect expected maximum capability

15 The Time Schedule Order associated with Alamos Generating Stations’ National Pollutant Discharge Elimination System permit expired on December 31, 2025. As such, maximum generation from the Alamos Generating Station may be reduced to meet the requirements of the NPDES permit such as high outfall water temperature restrictions, especially between May and October 2026.

16 DSGS capacity estimate reflects current authorized funding levels; capacity may vary with future funding decisions and program participation

17 Federal Power Act (FPA) section 202(c) (authorizes the Department of Energy to temporarily waive federal, state, or local environmental regulations during emergency conditions to maintain electric reliability).

Summer 2026 Outlook

The following are key takeaways for the Summer 2026 Outlook.

- **2026 Stack Analysis Results:** The latest baseline 2026 stack analysis projects a surplus of 6,635 MW under standard planning conditions, 4,540 MW under a 2020 equivalent event, and 2,911 MW under a 2022 equivalent event. There remains a summer reliability risk for coincident events, like a scenario combining a 2022 equivalent extreme heat event with wildfires that disrupt transmission lines, where there could be a shortfall of 1,000 MW.
- **Resource Stack Updates:** California's existing resource capacity has increased by over 2,200 MW since the last report, primarily due to updates in the 2026 NQC list. Expected new resources total 897 MW, with batteries making up 83% of the new capacity expected to come online by June 30, 2026.
- **California Energy Demand Forecast:** The projected peak demand for September 2026 is 46,546 MW, based on the newly adopted 2025 CED Forecast. This represents a decrease of 112 MW from the previous quarterly report. However, known loads identified through utility planning documents could add over 1,300 MW of additional demand. With the known loads added, the peak demand for September 2026 is 47,909 MW.

CHAPTER 6: Updated Probabilistic Reliability Assessment (CEC)

The CEC performed a probabilistic assessment of the statewide near-term reliability outlook using its RA model for California in 2026. The RA model incorporated installed capacity from the stack analysis discussed above. The goal of this assessment is to determine whether California is meeting the reliability criterion of 1 day in 10-year Loss of Load Expectation (LOLE),¹⁸ or 0.1 days per year LOLE with expected system build for 2026. The probabilistic assessment incorporates multiple reliability risks, combining uncertainty in resource availability, hourly demand, unexpected generator outages, and lower than expected imports. This assessment was conducted for every month in each year to better understand the shifting reliability risk over the study horizon due to changes in the load and resource mix.¹⁹

Several changes have been made to the CEC RA model since the release of the *First Quarterly Report for 2026 and SB 1020 Annual Report*. This assessment uses the updated 2025 CED Forecast with and without known loads as opposed to the 2024 CED Forecast. Further, CEC’s probabilistic RA model has been updated to better reflect the expected California system resource build as of the summer of 2026. Instead of relying on the CPUC 2023 preferred system plan (PSP) as a supply forecast, the resource build in this assessment reflects the resource build assumed in the stack analysis for California ISO balancing area and CEC Supply Form data for resources in the POU balancing areas.

The RA assessment finds that the current resource mix and resource additions through 2025 are sufficient to exceed the 0.1 LOLE reliability criterion and serve load under challenging demand, resource, and transmission conditions for summer and winter periods in 2026. Results of the scenarios and sensitivities are provided in Table 12.

Table 12: Statewide Reliability Assessment Results Across Scenarios

Scenarios	Units	2026
Base Scenario	LOLE (days/year)	0
Base Scenario with Known Loads	LOLE (days/year)	0
Base Scenario, Reduced Imports	LOLE (days/year)	0

Source: CEC staff

Finally, while study results indicate that California is expected to meet or exceed its reliability targets for 2026, this study does not evaluate all potential risks to the power system. Local generation or transmission outages during periods of particularly high demand coupled with limited imports could potentially lead to loss of load conditions. Further work is planned to

18 Loss of Load Expectation (LOLE) is a probabilistic reliability metric that measures the expected number of days per year when available generation capacity is insufficient to meet demand.

19 For this assessment, the 2025 CED Demand Forecast update, released January 2026, was implemented in the model.

evaluate the impacts of transmission outages, and reduced availability of new resources or imports, among others. Alternative load scenarios are also not evaluated, such as increased or different electric vehicle charging patterns or weather dependent electrification that may further drive summer or winter reliability risks.

RA Model Development and Key Assumptions

To evaluate the probabilistic reliability 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 reliability assessment, including the California ISO. This California-specific RA model was developed using public information to the maximum extent possible. Where relevant, CEC aligned key inputs and assumptions with the CPUC Resource Adequacy Study and the California ISO Summer Reliability Assessments.

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

While the overall model is consistent with previous analysis conducted by the CEC,²⁰ there are notable updates that have been made over the past several months. These changes have maintained a similar modeled reliability outlook for California. The list below provides an overview of the major changes implemented in the RA model.

- **Demand Update** – The CEC adopted a 2025 CED Forecast, which lowered forecasted peak loads and classified known loads as a distinct load modifier from the original forecast. The net peaks decreased relative to the previous 2024 CED Forecast.
- **California ISO import constraint** – The maximum import constraint was used for evening (hours 16-22) peaks across the summer in previous analyses. This constraint was added to winter months in this analysis, as the 2025 *CERRO* analysis found that California faces increased risk during the winter in the mid-term horizon (i.e., through 2035) and the likelihood for tightening supplies in winter months across the west.²¹ This import assumption will be explored more in future reports as electrification continues and additional system information outside of California becomes available.

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 13).

20 Yee Yang, Chie Hong, and Brendan Burns (CPUC). January 2026. Joint Agency Reliability Planning Assessment. California Energy Commission. Publication Number: CEC-200-2026-002.

21 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. Available at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=264559>.

RA Model Setup

The CEC’s RA model represents California power plants in detail while power plants outside the state are represented as generic imports. California is modeled as seven regions, including the three investor-owned utility service areas (PG&E, SCE, and SDG&E) grouped together as California ISO, as well as four publicly owned utility (POU) BAAs (Balancing Area of Northern California, 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 import limit of 11,665 MW per California ISO’s Maximum Import Capability limit. This import limit is reduced to 5,500 MW during summer reliability risk hours (i.e., H16-22) in July-September to reflect California ISO’s net import limit. To evaluate concerns of reliability risk during winter months, as discussed previously, CEC extends this net import limit during the months of January-March and November-December.²² Imports into California, as a whole, are limited to 12,450 MW in all hours of the day, subject to monthly energy limits.

The RA model utilizes the 2025 CED Forecast. Underlying demand and behind-the-meter solar are weather correlated and vary across 17 weather years representing weather in 2007 to 2023. All other load modifiers (i.e., building electrification, electric vehicles, and energy efficiency) do not vary by weather year. Additional details about the 2025 CED Forecast are presented in CHAPTER 2: Supply Forecast.

All resource additions and retirements for both California ISO and non-California ISO regions were sourced from EIA 930, Quarterly Fuel and Energy Report (QFER), and the California ISO Master Control Area Generating Capability List. Resource additions are based on CPUC procurement order NQC capacity requirements for LSEs. The retirements for existing plants in the database utilized in this analysis align with retirements identified in EIA 930 or otherwise announced.

A summary of RA model inputs and assumptions are provided below in Table 13.

Table 13. Additional RA Model Inputs and Assumptions

Model Input	Data Source	Description
Hourly Demand Profiles	CPUC Weather-Sensitive Load	<ul style="list-style-type: none"> • Shapes based on 2022 CPUC shapes • Energy and peaks scaled to 2025 IEPR CED • Load modifiers from 2025 IEPR CED
Resource Outage Rates	NERC ²³ 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	QFER	QFER Data reported in 2025

²² See 2025 Summer Loads and Resources Assessment. California Independent System Operator. May 2025. <https://www.caiso.com/documents/2025-summer-loads-and-resources-assessment.pdf>.

²³ North American Electric Reliability Corporation

Model Input	Data Source	Description
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 Bias Correcting High Resolution Rapid Refresh (2015-2023)	Simulated wind production profiles were calibrated to align with actual monthly generation totals from California ISO 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 between the seven modeled regions within California.
Hydroelectric Monthly Maximum Ratings	Hourly hydro generation reported in EIA 860	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 behind the meter-PV) are held during loss of load events. All other reserves are assumed to be curtailed prior to load shed.

Source: CEC staff

Probabilistic Reliability Assessment Results

2026 RA Base Scenario Results

California's power system risk has historically been defined by periods of high temperatures and low hydro availability. Near-term RA risks²⁴ are relatively limited due to significant additions of solar and batteries to the resource portfolio. With the California ISO stack supply in addition to POU resources through 2025, the RA model results project that California will have surplus resources, exceeding the 0.1 days/year LOLE reliability criterion, in the year 2026 across both the summer and the winter under normal hydro and transmission conditions. The resulting RA metrics are provided below for the three scenarios under evaluation.

- 2026 Base Scenario: No shortfall events
- 2026 Base Scenario, with known loads: No shortfall events
- 2026 Base Scenario, with reduced imports extended throughout the year: No shortfall events

These results are largely consistent with the 2025 *CERRO*. Although the 2025 CED Forecasted peak demand is lower than the 2024 CED Forecast, the demand for both is closely aligned in the year 2026. However, the reliability outlook has improved due to significant additions of solar and storage in recent years. These results indicate that the probability of resource shortfalls are very low in the near-term. Additional sensitivities were evaluated to test system reliability, including the addition of known loads and extending import limits throughout the year. Furthermore, widespread Western drought and/or wildfires could also challenge reliability but were not explicitly considered in this analysis.

Surplus Calculations

To provide additional context, the CEC quantified the amount of surplus capacity on the system beyond the 0.1 days/year LOLE reliability criterion for 2026 that met the criterion. This capacity surplus is calculated by adding firm load, applied as a constant capacity (MW) addition in all hours, until a 0.1 days/year LOLE is reached. Firm load is allocated to each region based on the region's contribution to forecasted coincident peak statewide load (e.g., 82% to California ISO). To calculate the effective capacity deficit, perfect generation is applied instead of firm load, until 0.1 days/year LOLE is reached.²⁵

This analysis finds a statewide surplus of 6-7 GW in 2026 under the Base Scenario. If known loads materialize in 2026 the surplus would likely drop by about 1,500 MW to 4.5-5.5 GW.

The surplus calculation assumes normal hydro conditions and transmission capability. This high level of reliability in 2026 is a result of significant additions of solar and storage and the near-term retention of Diablo Canyon Power Plant (DCPP). This analysis reports a Statewide surplus rather than the California ISO-only surplus as reported by the stack analysis. For each gigawatt of firm load and perfect generation added, only 82 percent is added into California

²⁴ California has a reliability criterion of a 1 day in 10 year Loss of Load Expectation (LOLE), or 0.1 days per year LOLE.

²⁵ Perfect generation represents a power plant operating at its nameplate capacity in all hours of the year and is a proxy to estimate capacity needs.

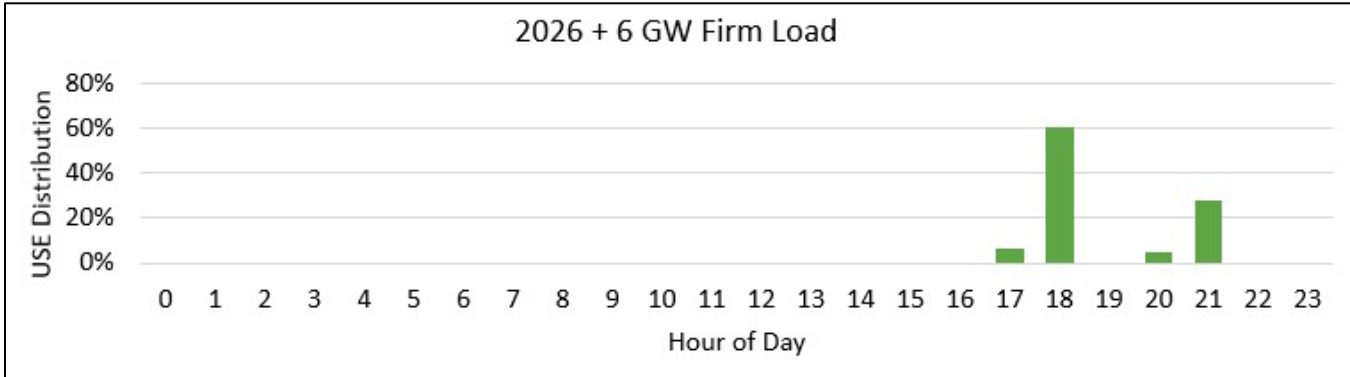
ISO regions; the other 18 percent is distributed to LADWP, BANC, TIDC, and IID commensurate with each region’s contribution to forecasted coincident peak statewide load. Using this factor to the 6-7 GW statewide surplus, the surplus for California ISO is about 4-5 GW, which is consistent with the 2020 equivalent event surplus projected in the stack analysis (see CHAPTER 5: Reliability Assessment).

Characterizing System Risk

To further characterize system risk, the 2026 scenarios were calibrated to meet approximately 0.1 days/year LOLE utilizing the firm load or perfect generation approach described in the previous section. Note that all events occur within the California ISO, which is subject to the California ISO maximum import capability limit. This analysis provides directional insights on the size, frequency, duration, and timing of reliability risk. While each scenario is calibrated to roughly 0.1 days/year, the underlying nature of the reliability risk shifts across the study horizon as the resource mix and load profiles evolve.

Figure 7 shows how unserved energy is distributed throughout the day (for days that show unserved energy) for calibrated study year 2026.²⁶ This analysis indicates reliability risks in early evening in 2026.

Figure 7: Unserved Energy Distribution throughout the Day for 2026 (% Unserved Energy)



Source: CEC staff

It should be noted that these results are provided for a system that was brought to the 0.1 days/year LOLE criterion by adding a constant firm load applied equally to all hours. For that reason, the demand profile is not necessarily representative of current or future demand, and the perfect generation does not necessarily represent how an installed generator would operate, particularly if it is a renewable or storage resource. While this is standard practice in reliability modeling, actual risk periods may be different as load grows, variable energy resources and storage are added and resources retire.

²⁶ Unserved Energy is the total amount of customer electricity demand that cannot be met by the power system over a specific period. It serves as a key measure of the magnitude and impact of power shortfalls.

Future Reliability Assessment

While this assessment provides an evaluation of reliability risks for California for this upcoming summer, it is not exhaustive. The energy agencies will 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 quantitative rigor to 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.

Drought Conditions and Wildfire Risks

This and other reliability and planning analyses typically assume normal hydroelectric conditions and often do not assess the potential for, or impacts of, wildfires, including loss of transmission capacity within the state and between neighboring states, and reduced solar production from smoke, particularly salient as California will increasingly rely on solar resources. The impacts of climate change and potential drought conditions will need to be captured in future studies to help prepare the state, and its power system, for potential challenges. Similarly, further evaluation is needed on wildfire risk potential and associated impact on both the transmission system and generation resources.

Summary: 2026 Probabilistic Reliability Outlook

California continues to meet its LOLE criterion of 0.1 days/year in the near-term throughout 2026. This holds true with the addition of known loads as well as reduced import capability year-wide. The analysis estimates a surplus capacity of 6-7 GW statewide above the 0.1 LOLE target. While the results from all scenarios indicate that California is expected to meet its RA targets for 2026, local generation or transmission outages during periods of particularly high demand, coupled with limited imports, could still lead to loss of load conditions.

APPENDIX A:

Acronyms and Abbreviations

BAA – Balancing Authority Area

California ISO – California Independent System Operator

CEC – California Energy Commission

CED – California Energy Demand Forecast

CERRO – California Energy Resource and Reliability Outlook

COI – California-Oregon Intertie

CPUC – California Public Utilities Commission

DCPP – Diablo Canyon Power Plant

DEBA – Distributed Electricity Backup Assets Program

D-Flex – Demand flex

DSGS – Demand Side Grid Support Program

DWR – Department of Water Resources

EIA – Energy Information Administration

GO-Biz – Governor’s Office of Business and Development

GW – Gigawatts

IEPR – Integrated Energy Policy Report

IOU – Investor-owned Utility

IRP – Integrated Resource Planning

LOLE – Loss of load expectation

LSE – Load-serving entity

MTR – Mid-term reliability

MW – Megawatts

NERC – North American Electric Reliability

NREL – National Renewable Energy Laboratory

NQC – Net qualifying capacity

PD – Proposed decision

PG&E – Pacific Gas and Electric
POU – Publicly owned utility
PRM – Planning Reserve Margin
PSP – Preferred system plan
PV – Photovoltaics
RA – Resource adequacy
SB – Senate Bill
SCE – Southern California Edison
SDG&E – San Diego Gas and Electric
SRR – Strategic Reliability Reserve
TAC – Transmission Access Charge
TED – Tracking Energy Development
TPP – Transmission Planning Process
WECC – Western Electricity Coordinating Council

APPENDIX B:

Glossary

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

- [California Energy Commission Energy Glossary](https://www.energy.ca.gov/resources/energy-glossary), available at <https://www.energy.ca.gov/resources/energy-glossary>
- [California Independent System Operator Glossary of Terms and Acronyms](http://www.caiso.com/Pages/glossary.aspx), available at <http://www.caiso.com/Pages/glossary.aspx>
- [California Public Utilities Commission Glossary of Acronyms and Other Frequently Used Terms](https://www.cpuc.ca.gov/glossary/), available at <https://www.cpuc.ca.gov/glossary/>
- [Federal Energy Regulatory Commission Glossary](https://www.ferc.gov/about/what-ferc/about/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](https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf), available at: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
- [US Energy Information Administration Glossary](https://www.eia.gov/tools/glossary/), available at <https://www.eia.gov/tools/glossary/>

Balancing authority area (BAA)

A geographic area where a single entity maintains the real-time balance between electricity generation and demand. California has five BAAs, including the California ISO.

Baseline Forecast

A demand forecast that projects future electricity consumption by extending existing trends, without accounting for additional state policies or programs.

Bridge contract

A short-term contract used by a load-serving entity to meet procurement obligations when a contracted resource is delayed.

Coincident peak

The demand each area contributes at the time of the overall system peak, as opposed to each area's individual maximum.

Contingency resources

Backup resources outside the normal resource stack that can be activated during extreme events, including emergency generation, demand response programs, and transfers from neighboring systems.

Integrated Energy Policy Report (IEPR)

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002) requires the California Energy Commission 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](#).

Investor-owned utility (IOU)

A privately owned utility providing electricity transmission, distribution, and generation services. California's three large IOUs are PG&E, SCE, and SDG&E.

Known loads

Additional electricity demand from new customer projects (such as data centers or industrial facilities) identified in utility planning documents but not fully captured in the baseline forecast due to uncertainty in completion timelines and utilization.

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)

A reliability metric measuring the expected number of days per year when generation is insufficient to meet demand. California's standard is 0.1 days per year (one day in ten years).

Nameplate capacity

The maximum rated output of a generator under ideal conditions, as specified by the manufacturer. Actual output is often lower due to weather, fuel, or operational factors.

Net qualifying capacity (NQC)

The amount of capacity that can be counted towards meeting RA requirements in the California Public Utilities Commission's (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 Independent System Operator system. CPUC Integrated Resource Planning procurement orders (D.19-11-016, D.21-06-035, D.23-02-040) also require counting of resources for compliance using the associated NQCs, which can be different to those used in the RA program, depending on the resource type and order.

Planning Forecast

A version of the managed forecast used for system-wide planning that excludes known loads due to uncertainty in their timing and completion.

Planning reserve margin

Planning reserve margin (PRM) is used in resource planning to estimate the generation capacity needed to maintain reliability given uncertainty in demand and unexpected capacity outages. A typical PRM is 15 percent above the forecasted 1-in-2 weather year peak load, although it can vary by planning area.

Publicly owned utility (POU)

An electric utility owned by a government entity such as a city or special district. POU's are not regulated by the CPUC and are governed by local boards.

Resource adequacy (RA)

A regulatory framework requiring LSEs to procure enough generation capacity to meet forecasted peak demand plus a reserve margin, ensuring sufficient resources are available to the grid.

Resource stack analysis

An analytical method comparing total projected supply against projected demand plus a reserve margin for peak summer days, used to identify surpluses or shortfalls under various scenarios.

Strategic Reliability Reserve (SRR)

A state program maintaining backup resources — including DWR emergency generation, Demand Side Grid Support, and Distributed Electricity Backup Assets — for activation during extreme grid conditions.

Unserviced energy

The total amount of customer electricity demand that cannot be met by the power system over a given period, measuring the magnitude of power shortfall