DOCKETED	
Docket Number:	21-ESR-01
Project Title:	Resource Planning and Reliability
TN #:	256229
Document Title:	First Quarterly Joint Agency Reliability Planning Assessment
Description:	Joint Agency Reliability Planning Assessment Covering the Requirements of SB 846 (First Quarterly Report for 2024) and SB 1020 (Annual Report)
Filer:	Xieng Saephan
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	5/8/2024 10:50:32 AM
Docketed Date:	5/8/2024

Joint Agency Reliability Planning Assessment

Covering the Requirements of SB 846 (First Quarterly Report for 2024) and SB 1020 (Annual Report)

Gavin Newsom, Governor
May 2024 | CEC-200-2024-006

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ACKNOWLEDGEMENTS

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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 2024, including the demand forecast, supply forecast, and potential high, medium, and low risks to reliability in the California Independent System Operator territory from 2023 to 2032, as required by Senate Bill 846. As required by Senate Bill 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

Please use the following citation for this report:

Yee Yang, Chie Hong, and Sarah Goldmuntz (CPUC). May 2024. *Joint Agency Reliability Planning Assessment*. California Energy Commission. Publication Number: CEC-200-2024-006.

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Introduction

California is experiencing 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) sets an ambitious target of powering all retail electricity sold in California and state agency electricity needs with renewable and zero-carbon resources by 2045 to reduce greenhouse gas emissions and help improve air quality and public health. The actions to achieve SB 100 are resulting in the addition of unprecedented quantities of clean energy resources, primarily utility scale solar and storage.

At the same time, climate change is causing substantial variability in weather patterns and an increase in climate-driven extreme events, which is resulting in more challenges to maintaining grid reliability. In 2020, a west-wide heat event resulted in rotating outages 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 megawatts (MW) of imports to the California Independent System Operator (California ISO) territory and 4,000 MW of overall import capacity to the state. In 2022, California experienced record high temperatures between August 31 and September 9, 2022. On September 6, 2022, the California ISO recorded a new record peak load at 52,061 MW, nearly 2,000 MW higher than the previous record. In late July 2023, parts of the West outside California experienced extreme heat, driving challenging and fast-moving market dynamics.

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 2024.

Senate Bill 1020 (Laird, Chapter 361, Statutes of 2022) requires the CEC, CPUC, and State Air Resources Board 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 Senate Bill 1020 is being incorporated into this joint agency assessment to fulfill the requirements of the annual Senate Bill 1020 report.

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 three challenges for the state:

- Planning: Timely and effective planning is the essential first step in guiding electric system reliability. Climate change is affecting the ability of existing models to assess reliability into the future, as each progressive year sees increasingly divergent weather patterns from historical norms. Planning models and approaches need to be enhanced to account for greater weather variability. The state will 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.

- Resource Scale: Although the state is experiencing a boom in new project development, challenges remain to achieve the scale and diversity of resources necessary to accomplish the transition. New strategies are needed to increase demand flexibility. Moreover, as supply chain disruptions for solar and storage have the potential to continue, the state needs a more diverse portfolio of new resources to reduce the risk from unexpected project delays. However, alternative technologies are generally more expensive until they reach scale, which would benefit from incentives or cost-sharing strategies to achieve greater diversity in the near term.
- Extreme Events: Extreme heat events and wildfires remain a threat to grid reliability, and the state could look to existing programs such as the Strategic Reliability Reserve to expand the resources capable of managing or reducing net-peak demand reduction during extreme events. The Strategic Reliability Reserve was established in 2022 to provide additional generation and demand resources to be used in extreme events.

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 2023 IEPR Planning Forecast from the *2023 Integrated Energy Policy Report (2023 IEPR)*. The planning forecast is the forecast scenario that will be used by the CPUC for its Integrated Resource Planning (IRP) efforts. In the planning forecast, the annual managed sales for the California ISO region increases from 216,000 gigawatt-hours (GWh) in 2023 to 257,000 GWh in 2033. The 1-in-2 summer peak increases from 46,000 MW in 2023 to 54,000 MW in 2033. The primary drivers for the increase in electricity demand are transportation and building electrification.

Supply Forecast

California has an IRP process that was established by Senate Bill 350 (De León, 2015) for the load serving entities (LSEs) and the largest publicly owned utilities (POUs) 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) reductions translates into an enormous level of procurement in the mid- and long term. Load serving entities and POUs are procuring new energy resources to meet reliability and GHG 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.

As part of the CPUC IRP process, the CPUC adopts a Preferred System Plan (PSP) in the "planning track," and then sets requirements for LSEs to plan toward that portfolio. The PSP is an optimal portfolio of resources for meeting state electric sector policy objectives at least cost to ratepayers. The IRP "procurement track" was initiated in 2019 to explore possible actions the CPUC could take to address potential reliability or other procurement needs. On February

15, 2024, the CPUC adopted a Decision on the 2023 Preferred System Plan and Transmission Planning Process portfolios, which – among other things - adopts an aggregated portfolio that reduces statewide yearly GHG emissions from the electric sector to 25 million metric tons by 2035. The decision provides an expected resource development portfolio for the California ISO to be utilized to plan transmission investments for their Transmission Planning Process. To date the CPUC has approved three decisions within its procurement track in the IRP rulemaking — D.19-11-016 covering the near term (ending in 2023) reliability, D.21-06-035 covering the midterm reliability, ending in 2028, and D.23-02-040 (supplemental midterm reliability) adding additional procurement to 2026 and 2027— ordering CPUC-jurisdictional load serving entities to procure a combined amount of 18,800 MW of net qualifying capacity of new electricity resources to come on-line between 2020 and 2028. The amount of new nameplate capacity identified in Preferred System Plans has also significantly increased year over year.

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 IRPs to guide their resource procurement for years, Senate Bill 350 established the requirement for the 16 largest POUs to adopt IRPs by January 1, 2019, and to submit those IRPs to the CEC for evaluation of consistency with Senate Bill 350 requirements, the state's GHG reduction targets, Renewables Portfolio Standard procurement requirements, and several other planning goals. The POUs filed IRPs in 2018-2019, and the CEC found they were consistent with Senate Bill 350 and other requirements. The publicly owned utilities are directed to update their IRPs every five years, and file and update with the CEC for a Senate Bill 350 consistency evaluation. The publicly owned utilities are currently in the process of filing IRP updates.

Tracking Project Development

The state has witnessed an extraordinary pace of new development in the past three years, with over 130 new clean energy projects coming on-line to serve load in the California ISO footprint during this time. Between 2020 and the end of 2023, the CPUC's IRP procurement orders and prior load serving entity procurement resulted in more than 15,000 MW of new nameplate energy resources, equivalent to more than 8,000 MW of new net qualifying capacity that can count toward resource adequacy capacity obligations.

There is a collaborative effort to track projects coming on-line to support reliability through the Tracking Energy Development Task Force. The task force is composed of the CEC, CPUC, California ISO, and the Governor's Office of Business and Economic Development (GO-Biz). The Tracking Energy Development Task Force reviews new energy projects critical for near-term reliability and provides support, as appropriate, for individual projects, identifies barriers, and coordinates actions across agencies to support all projects. The priority focus for the Tracking Energy Development Task Force has been near-term projects, defined as those that can come on-line in the next one to three years within California ISO territory. The Tracking Energy Development Task Force meets with developers to review projects under development and primarily works on interconnection and permitting delays. Through these coordination meetings with developers, the Tracking Energy Development Task Force has identified three key reasons for project delays: supply chain issues, interconnection delays, and permitting delays.

Reliability Assessments

The deterministic and probabilistic reliability assessment approaches used for this report looked at forecasted demand and supply for 2024–2034. Although SB 846 requires only considering the 5- and 10-year points, the CEC and CPUC included annual results for both analyses. The summer analysis for 2024 is preliminary and will be updated in the release of the SB 846 Second Quarterly Report by the end of June to capture relevant pre-summer conditions (e.g., hydroelectric updates). The analysis provides an overview of projects coming on-line in the near term (next 1–3 years) and describes barriers to new project development.

Near-Term Summer Reliability Assessment

The approach used for the near-term reliability assessment in this report is consistent with the previous deterministic Summer Stack Analysis included in past Senate Bill 846 Joint Reliability Quarterly reports, released in 2023. The analysis compares an hourly evaluation of anticipated supply against the projected hourly demand for the peak day of each month, July through September. The purpose of the stack analysis is to help understand the need for contingency resources under average and potentially extreme situations. Under a 17 percent reserve margin scenario, the CPUC's procurement orders and Preferred System Plan avoid reliability shortfalls well beyond the period covered by the current procurement orders. However, grid reliability risks will persist through 2030 under extreme heat, similar to the conditions experienced in 2020 and 2022. These risks are compounded by the risk of coincident wildfire impacting generation and/or electricity imports into California. Contingency resources may be necessary to avoid outages in these extreme events.

Mid- and Long-Term Probabilistic Reliability Assessment

CEC and CPUC both conducted probabilistic analyses for system reliability in the mid- and long-term planning horizons. While the analyses used different models and slight differences in methodologies, they used similar inputs and assumptions. These differences result in a more robust and complementary approach to evaluating the reliability of resource portfolios, potential risks, and system reliability for the entire state. The results from the analyses agree that the proposed 2023 Preferred System Plan meets the reliability standard through 2035. The CEC performed additional analysis around potential import and supply shortfalls and concluded the state remains reliable even under extreme scenarios.

Recommendations

The following recommendations are consistent with and built upon the efforts of the prior year. Updates to each recommendation are outlined:

- Continue to Improve Situational Awareness: The agencies should continue to track project development through the TED task force, as well as increase the transparency of transmission network upgrades and interconnection processes, through the Transmission Development Forum.
- Improve Planning Assumptions: The agencies should develop a common approach to better incorporate climate change into planning and evaluate whether changes to the planning reserve margin or other reliability metrics are warranted.

- Scale Demand-Side Resources: The CEC and CPUC should continue to collaborate to explore restructuring the state's demand response programs and maximize opportunities for demand response and demand flexibility. In July 2023, the CEC adopted revised Demand Side Grid Support Program guidelines to test approaches to maximize demand response and bring on more clean resources for the Strategic Reliability Reserve with two new incentive pilots for market-integrated demand response and market-aware battery storage virtual power plants. The Demand Side Grid Support Program staff are exploring how to further scale demand response opportunities in the program, such as incorporating vehicle-to-grid eligibility.
- Continue to Invest in Research, Development, and Demonstration: The CEC should continue to invest in applied research to support integrating climate considerations into planning and in increasing customer load flexibility. The state should also consider monies other than ratepayer funds, such as the Clean Energy Reliability Investment Plan. In 2023, the CEC funded projects that support demand flexibility in existing and new developments, supported technical discussions of the use of Global Warming Levels available through CEC funded tools, funded multiple long duration energy storage projects and secured additional federally funding to support grid resilience.
- Continue to Develop Resources for Extreme Events: The CEC and CPUC should continue to coordinate with Department of Water Resources (DWR), California ISO, other balancing authorities, and stakeholders to develop and expand extreme event resources to support the grid during extreme conditions. In 2023, 148 MW of in-state generating resources were available under DWR's Strategic Reliability Reserve program and the CPUC has authorized the extension of Diablo Canyon Power Plant until 2029 and 2030.
- Consider how regional coordination can enhance operational control and access to both supply and demand diversity. The West-wide Governance Pathways Initiative (Pathways Initiative) is an effort led by a group of stakeholders from the eleven western states in the Western Interconnection with the goal of creating a new entity with an independent governance structure capable of offering an expansive suite of West-wide wholesale electricity market functions across the largest possible footprint. The Pathways Initiative has developed and released for stakeholder feedback on potential governance structures which leverage existing infrastructure and experience of the Energy Imbalance Market and Extended Day Ahead Market. With these efforts, the Extended Day Ahead Market has continued to receive commitments from entities across the West. The CEC should continue to explore opportunities for enhancing reliability and affordability for ratepayers through this venue.
- Explore strategies to align developer and customer deployment plans with locations that have, or are planned to have, available transmission or distribution capacity. The California ISO published its Interconnection Process Enhancements Final Proposal on March 29, which aims to give greater priority to interconnection requests aligned with priority zones where transmission capacity exists or has been approved for development. Additionally, the California ISO published its Draft 2023-2024 Transmission Plan on April 1. This draft plan continues the zonal approach to transmission development the CAISO implemented in the 2022-2023 Transmission plan,

taking into account priority zones identified in resource portfolios to develop the transmission infrastructure required and recommended for approval.

CHAPTER 1: Introduction

Energy reliability in California and nationally is increasingly impacted by highly variable and unusual 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 these moments of extreme weather events coincide with other climate-driven extreme events — like drought or fire — the state's energy system could be strained beyond reliability contingencies historically planned for.

In 2020, a west-wide heat event resulted in rotating outages August 14 and 15, because of systemwide electricity shortages of about 500 megawatts (MW). In 2021, dry conditions resulted in a wildfire in Oregon that impacted transmission lines that California depends on for reliability, resulting in loss of 3,000 MW of imports to the California Independent System Operator (California ISO) territory. In 2022, the state experienced record high temperatures between August 31 and September 9. On September 6, 2022, the California ISO recorded a new record peak load at 52,061 MW,[1] nearly 2,000 MW higher than the previous record, despite significant efforts to reduce load during this peak period.

Since 2020 California energy entities have taken steps to address the potential imbalances between the electrical supply and demand in California, 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 (GO) substantially increased coordination and developed the Tracking Energy Development (TED) Task Force with GO-Biz to track new clean energy projects under development to help overcome barriers to their completion. In December 2022, the CPUC, CEC, and California ISO entered into a memorandum of understanding (MOU) that, among other objectives, tightens the link between resource procurement and transmission planning. The MOU was developed in light of the significant amount of new resources and transmission needed to meet state goals.[2] Additionally, the CEC revised the IEPR demand forecast to better account for climate change.

1 "California ISO Peak Load History 1998 Through 2022," via https://www.caiso.com/documents/californiaisopeakloadhistory.pdf

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

Between November 2019 and June 2023, the CPUC mandated an unprecedented amount of procurement, which will bring 18,000 MW of net qualifying capacity (NQC) by 2028.[3] In response to Assembly Bill 205 (Committee on Budget, Chapter 61, Statutes of 2022) (AB 205), the CEC and DWR have also begun building out the Strategic Reliability Reserve (SRR). The SRR, though in development during that summer, was able to provide support during the extreme heat event the state experienced between August 31 and September 9, including securing imports, additional backup generation, and load reduction that helped avert outages on September 6, when the California ISO recorded the highest demand ever in its territory. Even with these significant resource additions and strategic reserve resources, there exists uncertainty in the supply-and-demand balance in the 5- and 10-year horizons.

Overview of Reliability Challenges

Extreme weather events driven by climate change are contributing to increased energy reliability challenges in California and nationally. At the same time, the state has seen an unprecedented expansion in clean energy development, particularly solar and storage. However, it needs an even greater buildout of clean energy resources to meet near-term reliability and the long-term clean energy policy goals, embedded in Senate Bill 100 (De León, Chapter 312, Statutes of 2018) (SB 100). The interaction results in three fundamental challenges for the state:

- Planning: Timely and effective planning is the essential first step in guiding electric system reliability. Climate change is affecting the ability of existing models to assess reliability into the future, as each progressive year sees more and more divergent weather patterns from historical norms. Planning models and approaches need to be enhanced to account for greater weather variability. The state will 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.
- Resource Scale: Although the state is experiencing a boom in new project development, challenges remain to achieve the scale and diversity of resources necessary to accomplish the transition. New strategies are needed to increase demand flexibility. Moreover, as supply chain disruptions for solar and storage have the potential to continue, the state needs a more diverse portfolio of new resources to reduce the risk from unexpected project delays. However, alternative technologies are generally more expensive until they reach scale, which would benefit from supportive financing or cost-sharing strategies to achieve greater diversity in the near term.
- Extreme Events: Extreme heat events and wildfires remain a threat to grid reliability, and the state could look to existing programs such as the SRR to expand the resources capable of managing or reducing net-peak demand during extreme events. The SRR was established in 2022 to provide additional generation and demand resources to be used in extreme events.

3 In D.24-02-047 the Commission allowed for extension requests to be filed for LSEs' Long Lead Time (LLT) procurement obligation. LSEs that request extensions must procure additional generic or bridge resources until their LLT resources come online.

Senate Bill 846

Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) (SB 846) requires the CEC and the CPUC to submit a Joint Reliability Planning Assessment to the Legislature quarterly. The Joint Reliability Planning Assessment focuses on the California ISO's balancing area, specifically looking at the supply and demand balance for the forward 5- and 10-year periods under different levels of risk. There were four quarterly reports submitted in 2023. This report is the first of the 2024 quarterly reports and provides information on the California Energy Demand (CED) forecast, the supply forecast, a reliability assessment, and joint agency recommendations.

Senate Bill 1020

Senate Bill 1020 (Laird, Chapter 361, Statutes of 2022) (SB 1020) requires the CPUC, CEC, and State Air Resources Board, on or before December 1, 2023, and annually thereafter, to issue a joint reliability progress report that reviews system and local reliability within the context of that state policy described above, with a particular focus on summer reliability, identifies challenges and gaps, if any, 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. This is the first annual report, and the relevant content can be found in Chapter 6.

CHAPTER 2: Summer 2023 Reliability Summary

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

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

- **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. It is similar to the CPUC's Emergency Load Reduction Program, which is limited to customers in includes customers in investor-owned utility (IOU) territories but supports customers in both IOU and non-IOU territories. The CEC launched the DSGS program on August 10, 2022, with the adoption of program guidelines. On July 26, 2023, the CEC adopted revised program guidelines to bring on cleaner resources with expanded participation eligibility, additional incentive options for clean resources, including virtual power plants, and streamlined processes.
- **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 (GFO), the first of which is a $150 million GFO for bulk grid efficiency upgrades and capacity additions at existing bulk grid power plants released December 7, 2023. The CEC released a second draft GFO concept for distributed energy resources solicitations on February 23, 2024, and are targeting to release the final version in the second quarter of 2024.
- **The Electricity Supply Strategic Reliability Reserve Program (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. At its September 30, 2022, meeting, the Statewide Advisory Committee on Cooling Water Intake Structures

recommended that the State Water Board extend the compliance dates for three once-through-cooling plants to support the ESSRRP. This extension would allow the power plants to be available for contract to DWR as resources available in extreme events. The State Water Board approved the extension of the once-through cooling compliance dates at its August 15, 2023, meeting.

When fully operational, the SRR could provide up to 5,000 MW of additional extreme event support to the state. Both DSGS and ESSRRP were initiated during the summer to provide resources during summer 2022 and the program can expend funds up to June 2031.

The following recap of Summer 2023 events is summarized from the California ISO Summer Market Performance Report for July 2023.[4] This chapter will also capture the activities of additional balancing authorities in the state.

California Independent System Operator

Overall, reliability conditions in summer 2023 were relatively stable, with California better positioned on resource adequacy (RA) with record snowpack and strong hydro production, newly added generation and storage resources, and fairly mild temperatures compared to September 2022. In 2022, the California ISO issued a record 10 consecutive days of Flex Alerts[5] between August 31 and September 9, 2022. In comparison, the California ISO did not call any Flex Alerts in 2023 and issued fewer energy emergency alerts (EEAs).

Although overall conditions in summer 2023 were milder than the prior summer, in late July, the California ISO experienced challenging evenings of grid operations. During these times, there was high but not excessive demand in California, heavy demand externally at the interties because of record setting heat in the Desert Southwest, and reduced hydro from the Pacific Northwest. During the sudden onset of EEA 1 and EEA watches in July 2023, the California ISO worked quickly and closely with market participants and neighboring balancing areas to operate the grid reliably without escalating to higher emergency stages or implementing rotating outages.

During July, there were a few lessons identified to improve managing the grid during stressed system conditions. The California ISO's *Summer Market Performance Report July 2023* highlighted three main areas where California ISO could make improvements. The following changes have since been addressed:

- Ensure that exports are scheduled at a level that can be reliably supported by available supply and accounting for sources of uncertainties. The California ISO reiterated and clarified expectations about scheduling and tagging export transactions and

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4 The [California ISO Summer Market Performance Report for July 2023] can be found at https://www.caiso.com/Documents/Summer-Market-Performance-Report-for-July-2023.pdf

5 Flex Alerts are voluntary calls for consumers to conserve electricity. A Flex alert is typically issues 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.

implemented changes and clarifications to scheduling and tagging protocols for imports and exports.

- Harmonize the accounting procedures for intertie transactions between the California ISO and neighboring balancing areas.
- Improve operator visibility regarding the real-time availability of dispatchable capacity.

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 (SMUD), City of Shasta Lake, and Trinity Public Utilities District. The BANC footprint also includes the WAPA-Sierra Nevada Region (WAPA-SNR) and the 500 kilovolts (kV) California-Oregon Transmission Project (COTP) intertie to the Pacific Northwest. In preparing for summer 2023, 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 balancing authorities (BAs). 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 2023 with sufficient operating margins. The assessment also showed sufficient resources for extreme events such as wildfire smoke and California ISO reaching an 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 peak load occurred on August 16, 2023, and was 287 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) of approximately 300 MW due to derates on various 500 kV transmission lines owned by PG&E. This was offset in part by an increase of approximately 7 MW of net metered solar generation and an increase in hydro power generation due to the above normal water year in 2022/2023. It should also be noted that the Western Energy Imbalance Market (WEIM) performed well during 2023 demonstrating the benefits of peak diversity. BANC peaks approximately 90 minutes before the California ISO, which allows the California ISO resources to support BANC's peak followed by the BANC resources supporting California ISO's peak.

Some of the other efforts to maintain reliability are:

- Increased communications with members and other balancing authorities (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 2024, BANC will continue to conduct detailed summer assessments of anticipated reliability under different scenarios and to evaluate RA policies in response to heat events. BANC will continue coordination with other BAs, the state, and Department of Energy to identify resources that may be underused, including backup generators.

Conclusion

In summer 2023, the joint state agencies and BAs made significant preparations towards summer readiness. The SRR continued to be expanded, enhancing to the ability of the state to support the grid during extreme events. Favorable weather and continued resource build out, coupled with the absence of major fires impacting resources and transmission assets, meant that there were no significant grid challenges encountered throughout the year. Collaboration among joint state agencies and BAs, including the California ISO, and the BANC, played a crucial role in maintaining reliability. Looking forward, ongoing efforts in coordination, assessment, and policy evaluation will be essential to maintaining grid reliability into summer 2024.

CHAPTER 3: Demand Forecast

Demand Forecast Scenarios

As directed in SB 846, this reliability analysis uses the most recently available IEPR forecast. The most current forecast is the 2023 IEPR Planning Forecast from the adopted *2023 IEPR*.

2023 IEPR Planning Forecast Inputs and Assumptions

The demand forecast relies on several data sources as inputs. The baseline economic projection is from a Moody's Analytics scenario that is described as a "50/50" likelihood. Demographic projections (for example, population and number of households) are derived from California Department of Finance analysis. Other drivers in energy consumption forecasts are the retail cost of energy, adoption of behind-the-meter self-generation and energy storage technologies, building electrification, and vehicle electrification. The electricity rate scenarios incorporate recent and pending utility rates and rate actions; projected costs of electric generation procurement, transmission, and distribution revenue requirements; and other costs. Key drivers of increasing electricity rates for the 2023 IEPR forecast were the costs of wildfire mitigation, risk management, and other investment in the distribution grid to support state policy goals.

For planning areas within the California ISO balancing area, peak and hourly demand forecasts were developed using the CEC's top-down hourly load model (HLM). This model is at the system level and driven primarily by growth in annual consumption. The key functionality of the HLM is that it allows specific profiles for photovoltaic (PV), electric vehicle (EV) charging, and other load-modifying resources to be layered onto the baseline consumption profile, ensuring that the resulting peak forecast accurately captures the contribution of these resources.

System reliability planning in the context of a changing climate requires the demand forecast to consider a broad range of likely or possible weather patterns, as electricity demand is highly sensitive to temperature. The CEC's peak forecast must consider demand under normal peak conditions, as well as for the types of extreme temperatures that would be expected only once in 5, 10, or 20 years.

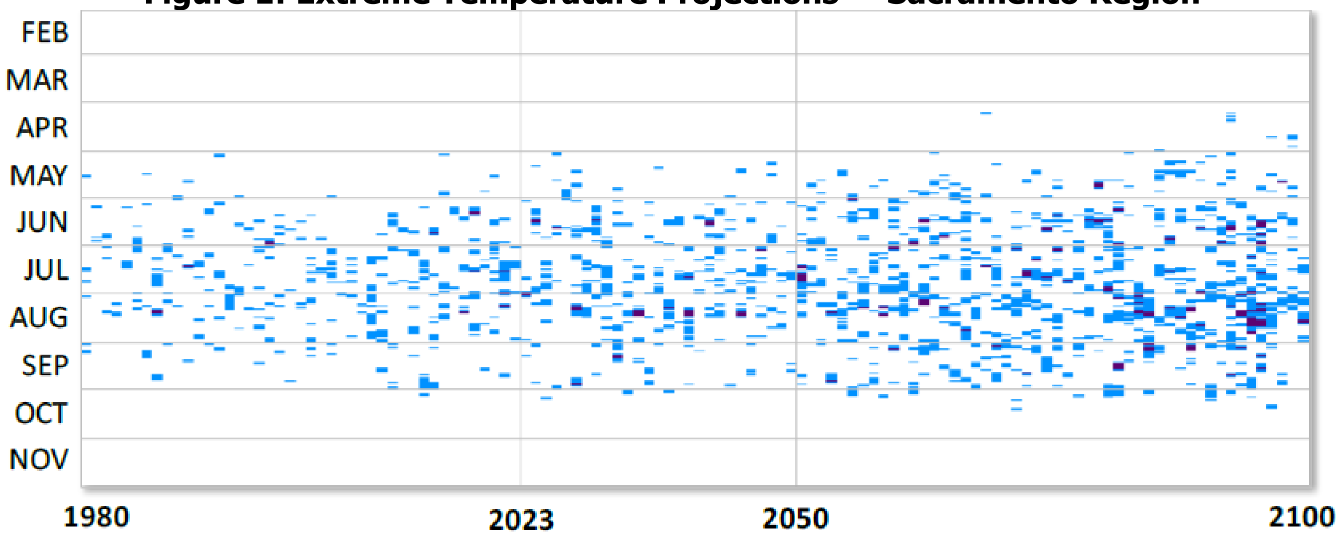
The 2023 IEPR forecast represents a shift away from the CEC's traditional practice of sampling only the historical record to define the range of possible weather patterns. Instead, it relies also on projected weather patterns from high-resolution projections derived from four global climate models (GCMs)[6] under the "Business as Usual" Shared Socio-Economic Pathway (SSP3-7.0) scenario.[7] Figure 1 illustrates the localized temperature projection for the Sacramento region under a GHG emission scenario rooted in the "Business as Usual" Shared Socio-

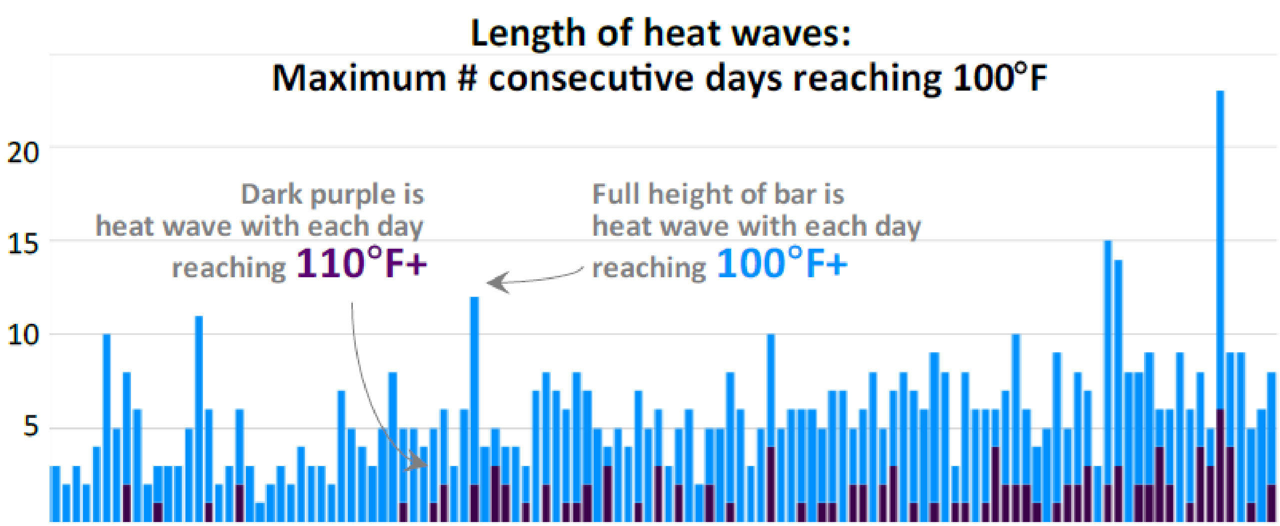
6 The four GCMs are CESM2, CNRM-ESM2-1, EC-Earth3-Veg, and FGOALS-g3.

7 This effort is supported by multiple EPIC applied research efforts, including the Cal-Adapt Analytics Engine.

Economic Pathway (SSP3-7.0). The graph shows an increase in the frequency of extremely hot days, prolonged heat waves, and an elevated number of warm months in the future. There is also a discernible upward trend in the number of days with a maximum temperature reaching 100 degrees Fahrenheit (100°F) throughout California. While previous forecasts have considered expected increases in *average* temperature, the trends depicted in Figure 1 underscore the importance of expanding climate considerations in the forecast to reflect novel weather patterns and changes to the magnitude, frequency, and duration of extreme temperatures.

Figure 1: Extreme Temperature Projections — Sacramento Region





Source: Lumen Energy Strategy

Staff is collaborating under Electric Program Investment Charge (EPIC)-funded agreements with Lumen Energy Strategy and Cal-Adapt: Analytics Engine team to improve climate considerations iteratively in the demand forecast and further validate approaches. This effort has identified further areas for improvement that will be taken up in future IEPR cycles.

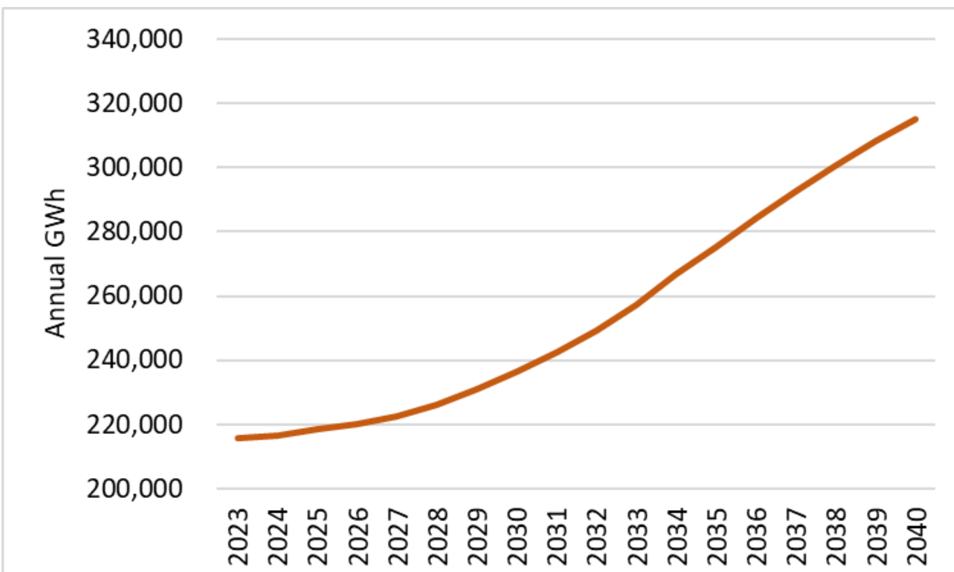
For more information on the 2023 IEPR forecast, see the *Adopted 2023 IEPR with Errata*[8] and the December 6, 2023, and December 19, 2023, IEPR workshop materials.[9]

2023 IEPR Planning Forecast Results

Figure 2 shows the annual managed electricity sales for the 2023 IEPR Planning Forecast for the California ISO region. The planning forecast shows annual managed sales, which is measured at the retail meter and net of behind-the-meter solar, increasing from 216,000 GWh in 2023 to 226,000 GWh in 2028, 257,000 GWh in 2033, and 315,000 GWh in 2040. Statewide annual managed sales will grow from 265,000 GWh in 2023 to 385,000 GWh in 2040.

The 2023 IEPR Planning Forecast results are lower than the 2022 IEPR Update Planning Forecast results through 2033 largely due to slower growth in projected households and population from the Department of Finance, increases in behind the meter (BTM) PV generation compared to previous assumptions, as well as increases in electricity rates compared to previous assumptions.

Figure 2: Annual Managed Sales for the 2023 Planning Forecast for the California ISO Region



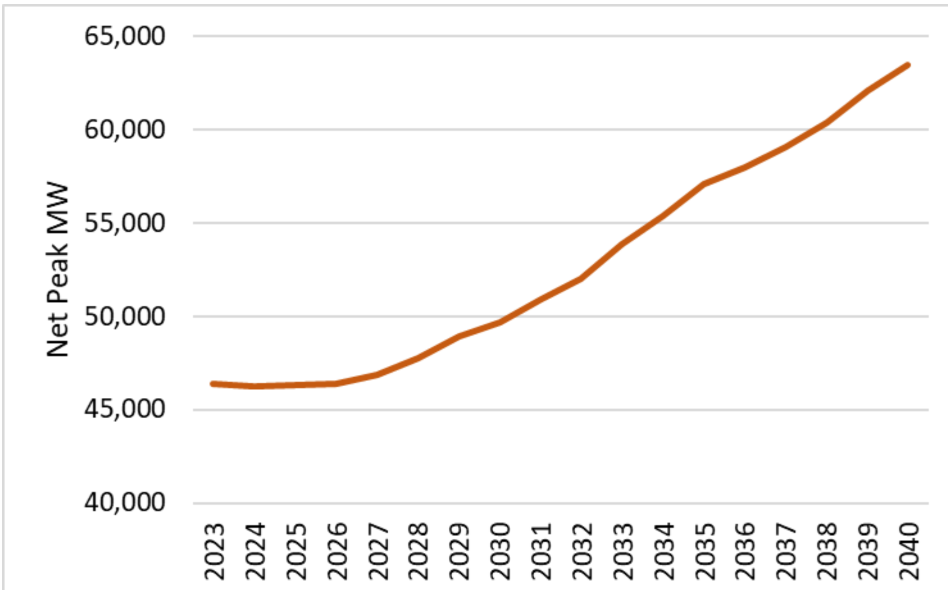
Source: CED 2023 Planning Forecast LSE and BAA Tables

8 Bailey, Stephanie, Jennifer Campagna, Mathew Cooper, Quentin Gee, Heidi Javanbakht, Ben Wender. 2023. *2023 Integrated Energy Policy Report*. California Energy Commission. Publication Number: CEC-100-2023-001-CMF. Available https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report/2023-1

9 IEPR Workshop 1 and IEPR Workshop 2 presentations and event recordings are available at https://www.energy.ca.gov/event/workshop/2023-12/iepr-commissioner-workshop-california-energy-demand-forecast-results and https://www.energy.ca.gov/event/workshop/2023-12/iepr-commissioner-workshop-california-energy-demand-forecast-results-part-ii.

Figure 3 shows the 1-in-2 2023 planning forecast results for net peak summer demand in California ISO territory. The 1-in-2 summer peak increases from 46,000 MW in 2023 to 48,000 MW in 2028, 54,000 MW in 2033, and 63,000 MW in 2040 for the California ISO region. Statewide, the coincident peak increases from 58,000 MW in 2023 to 67,000 MW in 2033 and 79,000 MW in 2040.

Figure 3: 1-in-2 Peak Summer Demand in the California ISO Region for the 2023 IEPR Planning Forecast



Source: CED 2023 Planning Forecast LSE and BAA Tables

Relative to the 2022 IEPR Planning Forecast, the 2023 IEPR Planning Forecast for the California ISO system is lower through 2033 due primarily to a lower baseline consumption forecast driven by slower growth in projected households and population from the Department of Finance and increases in electricity rates compared to previous assumptions. Additionally, improvements to the hourly forecast methodology resulted in the summer peak shifting to an earlier hour of the day in the initial years of the forecast, than was projected by the 2022 IEPR Planning Forecast. The earlier hour for the peak is consistent with the time that the peak has occurred in recent history. The ramp up to the peak demand is also more consistent with recent history than projected in previous forecast vintages. Overall, the hourly load profiles are improved and result in a lower peak than projected by the 2022 IEPR Planning Forecast because some generation from behind-the-meter PV generation is available at the earlier peak hour.

For more information on the changes to the hourly forecast methodology, refer to the December 19, 2023, IEPR workshop materials.[10]

Future Uncertainties

There are many uncertainties in forecasting electricity demand, with the largest uncertainties around climate change impacts and the adoption rates of transportation and building electrification.

Electrification of buildings and transportation will change energy-use patterns. There are numerous uncertainties around this, these uncertainties will need to be considered and monitored as electrification becomes more prevalent. The uncertainties include the rate of adoption of EVs and heat pumps, battery storage and EV charging patterns, and load flexibility and demand response. At the same time, utilities are considering rate strategies, such as real-time pricing, that encourage electrification and load shifting while ensuring grid reliability. As part of SB 846, the CEC set a load shift goal for the state.[11] The Load Shift Goal Report examines the potential for reducing load during peak demand hours. Future work will explore how that load can potentially be redistributed to best match supply.

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10 IEPR Workshop 2 presentations and event recordings are available at https://www.energy.ca.gov/event/workshop/2023-12/iepr-commissioner-workshop-california-energy-demand-forecast-results-part-ii.

11 *Senate Bill 846 Load-Shift Goal Report*. CEC-200-2023-008, https://www.energy.ca.gov/publications/2023/senate-bill-846-load-shift-goal-report.

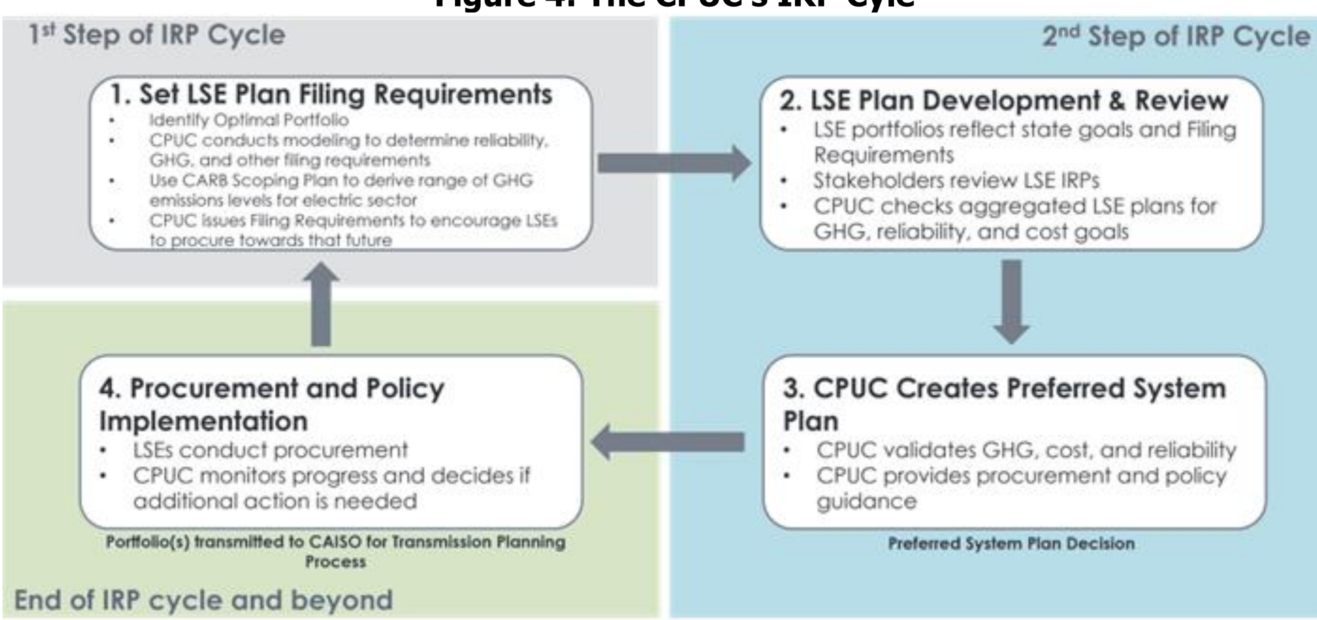
CHAPTER 4: Supply Forecast

Background

California has an IRP process that was established by Senate Bill 350 (De León, Chapter 547, Statutes of 2015) (SB 350) to plan for mid- and long-term procurement of energy resources. The process differs slightly for CPUC-jurisdictional entities versus non-CPUC-jurisdictional entities. The IRP process for CPUC-jurisdictional load serving entities (LSEs) succeeded the CPUC's longstanding Long-Term Procurement Planning (LTPP) process, established by Assembly Bill 57 (Wright, Chapter 835, Statutes of 2001). The CPUC IRP process aims to reduce the cost of achieving GHG 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, POUs submit IRPs to the CEC and are reviewed by CEC staff for consistency with SB 350 requirements.

The CPUC's IRP is a multi-step process**.** Figure 4 below lays out the major steps of the IRP Process. The first half of an IRP cycle builds on the findings of the previous cycle and is designed to provide analysis and guidance for those who provide power to the grid (LSEs) to use to plan for meeting their GHG, 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 goals, and to allow the CPUC to review each LSE plan and aggregate their portfolios to develop a preferred one (called a Preferred System Plan (PSP) portfolio), and to consider further related actions. The development and adoption of a Preferred System Plan represents the final step of an IRP cycle.

Figure 4: The CPUC's IRP Cyle



Source: CPUC Staff

CPUC IRP Planning Track

Preferred System Plan

The CPUC is currently in Step 3 of the IRP Cycle: On February 15, 2024, the CPUC adopted D.24-02-047 Proposed Decision[12] (adopting the 2023 PSP and Transmission Planning Process (TPP) Portfolios., which:

- **Adopts a Preferred System Plan:** The Decision adopts an aggregated portfolio that reduces statewide yearly GHG emissions from the electric sector to 25 million metric tons (MMT) by 2035 as compared to the previously adopted 38 MMT by 2030 planning target. The portfolio reflects the resource preferences of CPUC jurisdictional load-serving entities and includes an expectation that over 56 gigawatts (GW) of new clean energy resources will be built to serve load by 2035, including 4.5 GW of offshore wind. The PSP 25 MMT portfolio corresponds to the low end of the 2030 target range set by the California Air Resources Board when it adopted the most recent Scoping Plan update.
- **Transmits portfolios to the California ISO for the 2024-2025 TPP:** The Decision recommends to the California ISO that the 25 MMT PSP portfolio be utilized to plan transmission investments that will facilitate the 50 GW of new generation and storage in the adopted plan. The Decision requests that the California ISO use the reliability and policy-driven base case to establish the generation resource buildout for study in its 2024-2025 TPP. The Decision also recommends a policy-driven sensitivity portfolio that would help develop a better technical understanding of the transmission grid changes that could be necessary to accommodate potential future natural gas plant retirements.
- **Addresses two petitions for modification (PFMs) of existing IRP procurement orders:** The Decision denies a PFM jointly filed by Southern California Edison and Pacific Gas and Electric seeking a two-year extension from 2025 to 2027 on the capacity and energy required to be procured in D.21-06-035 to replace the reliability and zero-emissions energy attributes of the Diablo Canyon Power Plant (DCPP). The Decision notes additional flexibility may be considered in a future venue. Additionally, the Decision grants – in part and with modifications – the California Energy Storage Alliance and Western Power Trading Forum PFM seeking modifications to two IRP procurement decisions to allow the extension of deadlines for procurement of long lead-time (LLT) resources. LSEs requiring an extension of their LLT procurement beyond June 1, 2028, are required to procure generic capacity to cover the shortfall and still bring online LLT resources by no later than June 1, 2031.
- **Adopts a Reliability Framework Methodology for IRP:** The Decision formally adopts a high-level set of recommendations that the CPUC has been using for the past two years to determine whether the set of grid resources will provide sufficient

12 California Public Utilities Commission, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M525/K918/525918033.PDF

reliability. The Decision's framework creates a more consistent approach to counting each resource type's contribution to meeting reliability needs.

CPUC IRP Procurement Track

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 NQC of procurement from CPUC Jurisdiction LSEs from 2021-2028.[13] 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 the following table:

13 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

Table 1: 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 MW	1,650 MW	825 MW	825 MW	n/a	n/a	n/a	n/a	n/a
D.21-06-035 (MTR) Applies to all CPUC-jurisdictional LSEs. No opt-outs allowed.	11,500 MW	n/a	n/a	2,000 MW	6,000 MW	1,500 MW	n/a	n/a	2,000 MW
D.23-02-040 (Supplemental MTR) Applies to all CPUC-jurisdictional LSEs. No opt-outs allowed.	4,000 MW	n/a	n/a	n/a	n/a	n/a	2,000 MW	2,000 MW	n/a
Cumulative Procurement Ordered	18,800 MW	1,650 MW	2,475 MW	5,300 MW	11,300 MW	12,800 MW	14,800 MW	16,800 MW	18,800 MW

(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.

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

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

CPUC staff released the Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and (MTR D.21-06-035 Procurement using the February 2023 Data Filing.[14] All data released shows claimed procurement by LSEs towards MTR. Supplemental MTR D.23-02-040 was issued in March, after the February IRP Compliance Filings, and is not included in this data set. The tables (Table 2 to Table 7) below show LSE reported projected procurement MWs towards IRP procurement orders. These tables are not inclusive of procurement efforts beyond IRP.

Monitoring of D.19-11-016 and D.21-06-035 LSE Procurement Progress

CPUC staff are monitoring LSE Procurement Progress with IRP Procurement orders. As of the February 1, 2023, IRP Compliance Filings, LSEs are reporting:

- 3,927 MW NQC of total new procurement, collectively exceeding the D.19-11-016 3,300 MW procurement obligation.
- 8,301 MW NQC of procurement as under contract as progress towards the 11,500 MW NQC MTR procurement order.

More comprehensive information about compliance with IRP procurement orders can be found in the CPUC's report: Procurement in Compliance with D.19-11-016 and Mid Term Reliability (D.21-06-035) per February 1, 2023.

CPUC R.23-01-007

On January 12, 2023, the CPUC adopted Order Instituting Rulemaking (R.) 23-01-007 to implement the provisions of SB 846. In August, the CPUC approved Decision (D.) 23-08-004 for Phase 1, Track 1 of R.23-01-007, addressing funding issues for the Diablo Canyon Independent Safety Committee .

On December 14, 2023, the CPUC approved D.23-12-036 for Phase 1 Track 2 of R.23-01-007, which did the following:

- Conditionally authorized extended operations at DCPP through October 31, 2029, and October 31, 2030, for Units 1 and 2, respectively;
- Established new processes allowing the CPUC to consider the prudence and cost-effectiveness of extended operations at DCPP;
- Allocated the costs and benefits of extended operations among all load-serving entities subject to the CPUC's jurisdiction;
- Created a new non-bypassable charge to collect DCPP extended operations costs from customers of all load-serving entities subject to the CPUC's jurisdiction; and

14 Available at: D.19-11-016 (IRP Procurement Order) Background & Requirements (ca.gov) via https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/public-report-d19mtr-compliance-summaries-feb-2023-vintage1.pdf

- Required PG&E to begin filing in March 2024 an annual Extended Operations Cost Forecast application for the review and authorization of DCPPs extended operations costs by the CPUC and interested parties.

Upcoming SB 846-related items in the rulemaking include:

- In early 2024, commencement of Phase 2 of R.23-01-007 during which the CPUC will consider whether PG&E should provide upfront reasonable manager showings for CPUC review and approval, determine the process for DCPP cost review and true-up to actual costs and market revenues for the prior year, and establish the process for submittal and review of an annual compensation report and spending plan;
- On February 21 and 22, 2024, the Diablo Canyon Independent Safety Committee held its first meeting of the year at which it reviewed DCPP safety, seismic, and operational issues (reports and presentations can be downloaded at); and
- On March 29, 2024, PG&E filed its first DCPP Extended Operations Cost Forecast application with the CPUC. This application presents Diablo Canyon Power Plant costs of extended operations incurred from September 1, 2023, to December 31, 2025. The application can be found at: https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2403018/7162/528409344.pdf

Estimates of Resources Under Contract to CPUC-Jurisdictional LSEs

This section updates the estimated capacity under contract to CPUC-jurisdictional LSEs through 2027. Table 2 through Table 7 include resources being developed for compliance with IRP procurement orders as well as procurement for LSE compliance with Renewables Portfolio Standard (RPS) and procurement the CPUC approved in the Emergency Reliability proceeding.

All totals provided below represent the cumulative LSE-reported September NQC under contract to CPUC-jurisdictional LSEs. Developers often aim to bring projects on-line 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.
- Multiple California ISO resource identification numbers, once they come on-line.

Furthermore, LSE procurement activity is still ongoing to meet existing CPUC IRP procurement orders; some of the existing contracts will be delayed, and other contracts will be added, which is consistent with the cycle of energy project development. The authors emphasize that Table 2 to Table 7 do not include all known resources in development in California, nor in all of California ISO's footprint, and represent only resources known to be under contract to CPUC-jurisdictional LSEs between 2023 and 2027, as of October 2023. These totals are subject to change as the CPUC receives new data reports from LSEs, conducts field calls with developers and IOUs' interconnection departments, and continues to evaluate the data. Moreover, Table 2 through Table 7 do not comprehensively track all new megawatts already on-line and, instead, track CPUC Jurisdictional LSEs' reporting their contracts that have already come online in 2023 Q1 through Q3 and are forecasted to come online through 2027, inclusive of procurement beyond the scope of IRP.

Procurement by Transmission Access Charge (TAC) Area

Table 2: Estimated September NQC (MW) by TAC Area 2023 Q4 through 2025

TAC Area	2023 Q4	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2025 Q1	2025 Q2	2025 Q3	2025 Q4
East-Central	1,550	1,987	4,192	4,529	4,809	5,597	5,932	6,065	6,065
North	847	996	1,576	1,579	1,678	1,918	2,646	2,670	2,734
South	180	180	293	293	369	681	746	746	746
Other	491	491	678	678	874	875	974	1,090	1,091
Total	**3,068**	**3,655**	**6,739**	**7,080**	**7,731**	**9,072**	**10,299**	**10,571**	**10,637**

Source: CPUC Staff Aggregation of October 2023 LSEs' Procurement Status Reports

Table 3: Estimated September NQC (MW) by TAC Area 2026 through 2027

TAC Area	2026 Q1	2026 Q2	2026 Q3	2026 Q4	2027 Q1	2027 Q2	2027 Q3	2027 Q4
East-Central	6,073	6,331	6,331	6,331	6,331	6,356	6,356	6,356
North	2,812	2,987	2,987	2,990	3,190	3,290	3,290	3,290
South	746	746	746	746	746	746	746	746
Other	1,129	1,257	1,257	1,257	1,257	1,257	1,257	1,257
Total	**10,759**	**11,320**	**11,320**	**11,324**	**11,524**	**11,649**	**11,649**	**11,649**

Source: CPUC Staff Aggregation of October 2023 LSEs' Procurement Status Reports

Procurement by LSE Type

Table 4: Estimated September NQC (MW) by LSE Type 2023 Q4 through 2025

LSE Type	2023 Q4	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2025 Q1	2025 Q2	2025 Q3	2025 Q4
IOU	1,922	2,322	4,384	4,666	4,765	5,462	6,126	6,240	6,240
Non-IOU	1,146	1,333	2,355	2,414	2,966	3,610	4,173	4,332	4,398
Total	**3,068**	**3,655**	**6,739**	**7,080**	**7,731**	**9,072**	**10,299**	**10,571**	**10,637**

Source: CPUC Staff Aggregation of October 2023 LSEs' Procurement Status Reports

Table 5: Estimated September NQC (MW) by LSE Type 2026 through 2027

LSE Type	2026 Q1	2026 Q2	2026 Q3	2026 Q4	2027 Q1	2027 Q2	2027 Q3	2027 Q4
IOU	6,242	6,442	6,442	6,442	6,442	6,442	6,442	6,442
Non-IOU	4,517	4,879	4,879	4,882	5,082	5,207	5,207	5,207
Total	**10,759**	**11,320**	**11,320**	**11,324**	**11,524**	**11,649**	**11,649**	**11,649**

Source: CPUC Staff Aggregation of October 2023 LSEs' Procurement Status Reports

Table 6: Estimated September NQC (MW) by Resource Type 2023 Q4 through 2025

Resource Type	2023 Q4	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2025 Q1	2025 Q2	2025 Q3	2025 Q4
Solar	135	163	207	210	228	238	256	256	256
Battery	1,675	2,054	4,629	4,958	5,061	6,114	6,885	7,000	7,000
Paired/hybrid	1,179	1,341	1,796	1,805	2,171	2,448	2,813	2,950	3,015
Wind	57	57	57	57	57	57	74	74	74
Geothermal	21	21	31	31	190	191	242	263	264
Biomass/biogas	2	19	19	19	25	25	28	28	28
Total	**3,068**	**3,655**	**6,739**	**7,080**	**7,731**	**9,072**	**10,299**	**10,571**	**10,637**

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

Table 7: Estimated September NQC (MW) by Resource Type 2026 through 2027

Resource Type	2026 Q1	2026 Q2	2026 Q3	2026 Q4	2027 Q1	2027 Q2	2027 Q3	2027 Q4
Solar	259	259	259	259	259	259	259	259
Battery	7,000	7,416	7,416	7,416	7,616	7,641	7,641	7,641
Paired/hybrid	3,097	3,097	3,097	3,097	3,097	3,097	3,097	3,097
Wind	74	165	165	165	165	165	165	165
Geothermal	300	356	356	361	361	461	461	461
Biomass/biogas	28	28	28	28	28	28	28	28
Total	**10,759**	**11,320**	**11,320**	**11,324**	**11,524**	**11,649**	**11,649**	**11,649**

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

California ISO-area POU Supply

POUs have separate processes for planning and procuring to meet their reliability and clean energy requirements. POUs and other small utilities make up about 10 percent of the total energy demand in the California ISO region.

POUs provide information on planned new supply in their IRPs and through CEC's supply forms. IRPs were last reported to the CEC in 2019, consistent with the POU IRP program design that CEC administers. Thus, the data on POU expected additions from IRPs is relatively outdated. However, the CEC collects expected supply data from these entities through the supply form filings, most recently collected in the Fall of 2022. The 2022 supply form filings for the POUs in the California ISO balancing authority area include nearly 1,200 MW of new nameplate capacity, see Table 8, which translates to about 300 MW of NQC within the California ISO territory, see Table 9.

Table 8: POU Supply Plan Cumulative Nameplate Capacity Additions (MW)

	2023	2024	2025	2026	2026	2027	Total New Resources by 2027
Hybrid	19	125	125	125	125	125	644
Battery storage	8	8	8	8	8	8	48
On-Shore Wind	22	22	622	721	820	820	3027
Solar PV	127	127	227	227	227	227	1162
Geothermal	0	0	0	0	0	20	20
Total	176	282	982	1,081	1,180	1,200	4901

Source: POU Supply Form Filings to the CEC

Table 9: POU Supply Plan Cumulative NQC[15] Capacity Additions Estimates (MW)

	2023	2024	2025	2026	2026	2027	Total New Resources by 2027
Hybrid	10	57	57	57	57	57	295
Battery storage	8	8	8	8	8	8	48
On-Shore Wind	6	6	6	26	46	46	136
Solar PV	102	102	202	202	202	202	1012
Geothermal	0	0	0	0	0	10	10
Total	126	173	273	293	313	323	1501

Source: POU Supply Form Filings to the CEC

The analysis in this report will not include these additional resources to avoid the potential for double counting of resources that are contracting with both CPUC and non-CPUC jurisdictional entities and due to the lack of current information on POU contract commitments. This has been identified as an improvement for future reports.

15 Based on conversation to NQC using the CPUC's Qualifying Capacity accounting rules. California Public Utilities Commission, "QC Manual 2020," available at https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/q/6442466773-qc-manual-2020.pdf.

CHAPTER 5: 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 GO substantially increased coordination and developed the Tracking Energy Development (TED) Task Force with the Governor's Office of Business and Economic Development (GO-Biz) to track new clean energy projects under development to help overcome barriers to their completion. Figure 5 shows a list of resource tracking efforts and their frequency. 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 Joint Agency TED Task Force continues to track new energy projects being developed in California and bring state policy makers information about issues facing energy project deployment in the state. The TED Task Force continues to have regular check-in meetings with developers to review the status of near-term projects. Additional ad-hoc meetings are scheduled to review specific project challenges and, when applicable, for the TED Task Force to coordinate actions across member agencies.

In 2023, the TED Task Force engaged with stakeholders representing more than 100 clean energy generation projects under development, including developers, LSEs, permitting entities, associations, local and federal government agencies. Issues and challenges arising during the course of project deployment, which can take several years from start to finish, are complex. The major barriers to timely project deployment include:

- Interconnection issues including network upgrades;
- Supply chain problems;
- Permitting challenges; and
- Other delays during project execution such construction and extreme weather.

CPUC staff continues to meet regularly with Southern California Edison (SCE), Pacific Gas and Electric (PG&E), and San Diego Gas and Electric (SDG&E) interconnection teams to track progress on interconnection of projects, particularly for resources set to come online in the near future to support reliability. The IOUs report on projects at risk of delays and CPUC staff will support efforts to limit, as much as possible, delays in getting resources interconnected. CPUC staff also use these meetings to inquire about project issues reported by developers or LSEs.

Related to the TED Task Force's efforts, the California ISO, in conjunction with the CPUC, hosts the Transmission Development Forum on a bi-annual basis to provide stakeholders with status updates on transmission projects and related information. The most recent meeting was held in January 2024. Additionally, CPUC and CEC staff have continued to collaborate with the

California ISO on its 2023 Interconnection Process Enhancements stakeholder initiative. In this policy initiative, the California ISO is pursuing significant reforms to its interconnection queueing processes to address the unprecedented interconnection request volumes that are unsustainable in the current California ISO process. A more detailed description and status of the 2023 Interconnection Process Enhancements initiative can be found at the end of this chapter.

Separately, on July 27, 2023, FERC Issued Order No. 2023 Improvements to Generator Interconnection Procedures and Agreements, which contains several new requirements for transmission providers. The 2023 Interconnection Process Enhancements policy will complement FERC Order No. 2023 with additional interconnection process enhancements.

Figure 5: Resource Tracking Efforts

FREQUENCY	ACTION
Ongoing	TED TF conducts outreach to developers with a large number of projects under development to review status of projects and issues, if any.
Ongoing	Ad-hoc meeting with developers and others about specific project challenges.
Weekly	TED TF meets weekly to review issues, developer requests for assistance and provide updates.
Monthly	CPUC receives and compiles submitted data from LSEs on resources under contract for the near-term.
Monthly	CPUC compiles data on new MWs online.
Monthly	CPUC hold calls with IOU interconnection teams to review projects, pinpoint discrepancies, and identify operational areas for improvement.
Quarterly	CAISO, in conjunction with CPUC, hosts the Transmission Development Forum to discuss delays to transmission projects including network upgrades.
Quarterly	TED TF provides progress update to SB 846 Joint Agency Reliability Report.

Source: CPUC Staff New Additions to Date + 2023 Resource Additions

As evidenced in, one of the most notable trends in new resource additions is the growth of energy storage, with 2,529 MW (nameplate) brought online in 2023 alone and 6,240 MW (nameplate) brought online between 2020 and 2023. Additionally, although there were some larger units brought online in 2020, the natural gas capacity growth has been minimal. CPUC staff estimate that the new generation and storage investments in 2022-2023, largely driven by CPUC IRP requirements, represent approximately $7 billion in new infrastructure investment in California in the past two years.

Table 10: Cumulative New Resource Additions, in 2023 and for January 2020 through December 2023

Technology Type	Nameplate Capacity (MW)	Estimated Sept. Net Qualifying Capacity (NQC) MW	Number of Projects	Nameplate Capacity (MW)	Estimated Sept. Net Qualifying Capacity (NQC) MW	Number of Projects
	2023	**2023**	**2023**	**2020-2023**	**2020-2023**	**2020-2023**
Storage	2,529	2,295	34	6,240	5,916	84
Solar	2,482	154	36	5,743	468	83
Hybrid (Storage/Solar)	470	204	6	1,386	604	21
Wind	178	30	2	878	125	21
Geothermal	-	-	0	41	31	1
Biomass, Biogas, Hydro	5.4	-	2	39	0	10
Subtotal Total New SB100 Resources, California ISO	**5,665**	**2,638**	**80**	**14,326**	**7,143**	**220**
Natural gas, incl. Alamitos & Huntington Beach	-	-	0	1,477	1,474	12
Total New Resources, California ISO	**5,714**	**2,638**	**80**	**15,803**	**8,617**	**232**
New Imports, Pseudo-Tie or Dynamically Scheduled	50	50	1	1,739	777	14
Total New Resources, including Imports	**5,764**	**2,688**	**81**	**17,542**	**9,394**	**246**

Source: CPUC staff

Much of the new resource development has been concentrated in Southern California, particularly Riverside, San Bernardino, and Kern counties. These areas not only have abundant solar resources that developers can pair with energy storage, they also contain much of the state's wind resource capacity. Outside of Southern California, developers took advantage of the grid infrastructure built to interconnect natural gas facilities in Moss Landing, California by installing a significant amount of energy storage at an adjacent site. This minimized the need to construct new grid ties at ratepayer expense.[16]

Broadly speaking, a large portion of new resource development can be attributed to large projects that come online in phases. The approximately 700 MW Daggett Solar and Storage project, for example, came online in piecemeal approach from July to December of 2023. Similarly, the Edward Sanborn solar and storage project (currently about 800 MW) came online in phases that stretched from 2021 to 2023.

Finally, regarding out-of-state procurement, the end of 2021 saw the addition of over 800 MW of New Mexico wind, and new solar and storage resources from Nevada came online in mid-2023. Increased transmission connections to neighboring states, both planned by the California ISO and in-development, will increase the amount of out-of-state procurement.

Supply Chain Challenges

While in prior years, there were substantial issues with the supply chain for major project components (e.g., solar panels, battery storage), more recently, circuit breakers have been identified to be in short supply globally. Circuit breakers are critical to switching high voltage transmission lines safely and reliably. As renewable generation is added to electric grids, internationally as well as domestically, more circuit breakers are required to establish each generation resource's interconnection. The additional interconnections, in turn, raise the reliability profile at substations at which the interconnections are added, triggering the need for more complex bus configurations requiring additional circuit breakers. The current estimate for delivery of a 230 kV circuit breaker is reportedly 200 weeks from the time it is ordered.

Challenges for Battery Energy Storage System Projects

Renewable energy such as solar and wind are intermittent, and battery energy storage systems (battery storage) are key to providing reliable power. California has seen substantial growth in energy storage in recent years, and California has the greatest installed capacity of any state in the U.S. – more than twice as much as the next state. However, there are concerns from permitting entities and communities near and around where the projects are built, primarily from concerns about safety risks. While safety risks such as battery fires and associated emissions from those files challenge the development of these resources in the state, code improvements and system designs have improved in recent years and manufacturers continue to provide outreach and education to permitting entities to inform safety procedures and standards.

Recognizing these concerns and that more than half of the total MWs expected to come online by the end of 2027 will come from battery storage projects, the CEC, in conjunction with the GO-Biz and CPUC, hosted a workshop on February 23, 2024 to examine challenges and barriers to deployment of battery storage projects including safety risks and best practices on

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16 "Vistra Completes Milestone Expansion of Flagship California Energy Storage System." Vistra Corp. Available at https://investor.vistracorp.com/2023-08-01-Vistra-Completes-Milestone-Expansion-of-Flagship-California-Energy-Storage-System.

system design, construction, and operation. Given the enormous role battery storage can contribute to helping California reach its energy reliability goals, the workshop kickstarted an important conversation about the need for stakeholders to work collaboratively to develop a better and common understanding of how battery storage technology can be designed and installed properly to operate both safely and reliably. A key topic at the workshop was describing best practices for the planning, siting, permitting, commissioning, and ongoing operations of these systems.

A key takeaway from the workshop is continued engagement with and among stakeholders, including local and state government, developers, manufactures and community groups. As battery storage technology continues to evolve and experience with these systems grows, it is critical that the informational exchange, education, and training continue. The workshop organizers are exploring next steps, including opportunities to partner with stakeholders on future collaboration on education and outreach efforts.

California ISO 2023 Interconnection Process Enhancements (IPE)

The 2023 IPE initiative is focused on enhancing coordination of resource procurement and interconnection, resource planning, and transmission planning to achieve state reliability and policy goals by streamlining the California ISO interconnection process. The California ISO's proposed changes align with the strategic direction established by a December 2022 Memorandum of Understanding between the California ISO, CPUC, and CEC, and is part of a broader effort to tighten linkages among resource and transmission planning activities, interconnection processes, and resource procurement. CPUC staff participated in workshops and submitted comments to the California ISO in support of the reforms proposed throughout the process.

The Track 1 IPE Final Proposal, released in April 2023, focused on immediate adjustments to the schedule for processing Cluster 15 interconnection requests, resulting in the California ISO postponing until April 1, 2024, the interconnection study process for Cluster 15. The California ISO opened the normal cluster window for Cluster 15 requests in April 2023, but paused the interconnection study process to allow the California ISO and its transmission owners to finish Cluster 14 interconnection studies and develop enhanced interconnection procedures for the new reality of voluminous cluster studies.

On March 28, 2024, the California ISO published a Final Track 2 Proposal. The IPE Final Proposal outlines a significantly reformed process to address the surge in interconnection requests and expedite the integration of new clean energy resources. The Track 2 Final Proposal includes the following reforms:

- Zonal Approach: the California ISO will provide information to developers prior to the opening of the interconnection window, encouraging interconnection requests in transmission zones with available transmission capacity.
    - The California ISO will study sufficient capacity to accommodate 150% of the available capacity of each zone
- Scoring criteria to prioritize and advance interconnection requests to progress to the study process

- Sealed-bid auction as a backstop mechanism
  to right-size the number of projects and capacity in the study process
- Require projects transferring deliverability to another project in the queue to withdraw from the queue after transferring
- Require all projects in the queue to demonstrate commercial viability to remain in queue beyond seven years, regardless of deliverability status

The Final Proposal is expected to go to the California ISO Board of Governors in May, 2024. [17]

17 The California ISO's final proposal can be found here: https://www.caiso.com/InitiativeDocuments/DraftFinalProposal-InterconnectionProcessEnhancements2023.pdf https://www.caiso.com/InitiativeDocuments/FinalProposal-InterconnectionProcessEnhancements2023Track2.pdf

CHAPTER 6: Near-Term Reliability Assessment and SB 1020

The near-term reliability assessment approach used for this chapter was conducted by CEC staff and is consistent with the Summer Stack Analysis for 2022-2026 published by the CEC in July 2022[18] and past SB 846 quarterly reports[19]. Chapter 7 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 a 17 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.

In accordance with SB 1020, this report utilizes insights from the 2024 Local Capacity Area study conducted by the California ISO. The study focuses on determining the minimum capacity required in transmission-constrained "load pockets" or Local Capacity Areas to meet mandatory reliability standards.

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 2023 CED Planning Forecast.[20] Additional information on this can be found in CHAPTER 3: Demand Forecast.
- **Conditions Relative to the 1-in-2 Forecast**: This analysis explores 3 system conditions (Table 11). First, the current RA planning standard of 17 percent beginning in 2024. Second, a 2020 equivalent event that experiences 50 percent higher forced outages and demand variability, equating to the need for a 22.5 percent margin above the forecasted peak demand. Finally, a 2022 equivalent event that further increases the demand variability to 12.5 percent to align with the demand variability seen in the September 2022 event, equating to a 26 percent margin above the forecasted peak. All of these conditions were also evaluated under a coincidental fire risk that reduces the

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18 Craig, Hannah. 2022. Summer Stack Analysis for 2022-2026. California Energy Commission. Publication Number: CEC-200-2021-006-REV. Report available at https://efiling.energy.ca.gov/getdocument.aspx?tn=244116

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

20 California Energy Commission, "2023 CED Planning Scenario," is available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=253682&DocumentContentId=88934.

total import capacity by 4,000 MW, similar to what the state experienced in 2021 during the bootleg Fire in Oregon.

Table 11: System Conditions Defined

Condition Relative to 1-in-2 Forecast	Operating Reserves	Outages	Demand Variability	Coincidental Fire Risk	Notes
Current RA Planning Standard – 17%	6%	5%	6%		17% beginning 2024
2020 Equivalent Event: Additional capacity needed to weather heat event like 2020	6%	7.5%	9%	4,000 MW	9% higher demand over median, and 2.5% higher levels of outages
2022 Equivalent Event: Additional capacity needed to weather heat event like 2022	6%	7.5%	12.5%	4,000 MW	12.5% higher demand over median, and 2.5% higher levels of outages

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

- **CPUC January 18, 2023, NQC list:**[21] Existing resources located within the California ISO are based on this list, including resources online through October 2022. This list is used in the 10-year stack analysis.
- **California ISO December 2023 NQC List**[22]: Used for existing resources in the 2024 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[23]. For the purposes of the stack analysis, the mid-term reliability procurement is used for the 10-year outlook for years 2025 to 2034 while the near-term 2024 summer outlook used the California ISO queue data.

21 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/cpuc-final-net-qualifying-capacity-report-for-compliance-year-2023-17jan23.xlsx

22 https://www.caiso.com/Documents/FinalNetQualifyingCapacityReportForComplianceYear2024.xls

23 https://www.caiso.com/Documents/Generator-Interconnection-Resource-ID-Report.xlsx

- **Demand Response (DR):** The IOU DR monthly projections are published by the CPUC in their Load Impact Protocol Reports.[24] These numbers are used in addition to the CPUC's November 2023 NQC list for the baseline demand response. The DR numbers, in Table 12, are assumed to be fixed to 2034 because the IOUs do not forecast or report DR numbers to a 10-year horizon. Future studies will continue to make improvements on the representation of DR and to improved alignment between the CPUC and CEC characterization of DR in their analyses.

Table 12: 2023 Aggregated DR Numbers Reported by IOUs

	July	August	September
Demand Response (MW)	1,057	1,075	1,052

Source: CEC Staff with Load Impact Protocol Report data

- **RA Imports**: Standard imports are set to 6,000 MW in every hour. The 6,000 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 6,000 MW of RA imports, the stack analysis includes contributions from out-of-state wind resources on new transmission interconnected directly into the California ISO above this total 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 balancing authority footprint. These are based on historic generation on high-load days between 2014 and 2023. Out-of-state wind resources are included in the stack based on the expected effective load carrying capability (ELCC) values for those resources.[25]
- **Battery Storage**: Battery storage is limited to 4 hours of total discharge within a 24-hour stack. Storage is optimized so that the shortfall in any given hour is equal or less than the capacity shortfall at net peak. The full nameplate capacity for battery storage is included in the stack, rather than the ELCC values because discharge limits are directly incorporated. See Hourly Wind, Solar, and Battery Shapes, below for additional information.

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24 SCE: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/public-sce-file---py2024---py2026-lmr-and-ss-dr-lip-nqcs-wdlf.xlsx
PG&E: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/public-pge-file---py2024---py2026-lmr-and-ss-dr-lip-nqcs-wdlf.xlsx
SDG&E: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/public-sdge-file---py2024---py2026-lmr-and-ss-dr-lip-nqcs-wdlf.xlsx

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- **Contingency Resources and Retirements**: The stack analysis assumes Once-Through-Cooling (OTC) plants are removed from the supply stack and considered as contingency resources under the SRR) and DCPP retires based on new retirement dates of October 31, 2029 (Unit 1) and October 30, 2030 (Unit 2). DCPP 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. Beginning in 2024, the three fossil gas-fired plants removed from the stack were Alamitos Generating Station, Huntington Beach Generating Station, Ormond Beach Generating Station (Ormond Beach). These resources are not being made available to provide contracted RA. The OTC net qualifying capacity removed from the supply stack is 2,859 MW.

Supply Scenario

Delay Scenarios: Given that there are uncertainties in when new clean energy resources coming online (for example, supply chain, 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. The delayed capacity is assumed to come online in the following year without any additional delay.

MTR Procurement Order and Additional Resource Builds

The CPUC provided information on the projected new resources based on the total resource build for the 25 MMT core portfolio based on the proposed 2023 PSP portfolio from the October 2023 ALJ Ruling[26]. 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 13.

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Table 13: TOTAL Builds in 25 MMT Core Portfolio (Nameplate MW)

Resource Type	2024	2025	2026	2027	2028
Coal	0	0	0	0	0
CCGT	0	0	0	0	0
Peaker	0	0	0	0	0
Reciprocating Engine	0	0	0	0	0
Steam	0	0	0	0	0
CHP	0	0	0	0	0
Nuclear	0	0	0	0	0
Geothermal	0	0	783	931	1143
Biomass/Biogas	0	0	0	86	171
Hydro	0	0	0	0	0
In-State Wind	314	403	824	910	1079
Out-of-State Wind	11	642	1671	2533	3409
Solar	3000	6000	6488	7183	8528
Battery storage (4-hr)	4340	6284	7996	8018	9028
Battery storage (8-hr)	8	14	526	789	1058
Pumped Hydro Storage	0	0	0	239	477
A-CAES	0	0	0	100	200
Shed DR	0	0	0	0	0
TOTAL	**7673**	**13343**	**18288**	**20789**	**25093**

Source: CPUC Data

The resource needs established by the CPUC's procurement orders were developed using the 2020 CED mid demand update[27] and only include procurement through 2028. The option to delay procurement of the long lead time resources, which are assumed to be geothermal and 8-hour batteries, from 2026 to 2028 is assumed to be taken. Thus, in this scenario, the long lead time resources that are not already under contract arrive in 2028.

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 2014-2023. Using historic hourly demand data from the California ISO Open Access Same-time Information System (OASIS) portal, the median wind generation value for each hour of the day was calculated based on the five highest-load days of each month for each year 2014-2023. The 20th percentile for the wind generation value 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.

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

27 Bailey, Stephanie, Nicholas Fugate, and Heidi Javanbakht. 2021. *Final 2020 Integrated Energy Policy Report Update, Volume III: California Energy Demand Forecast Update*. California Energy Commission. Publication Number: CEC-100-2020-001-V3-CMF.

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:

1. First, 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 4 total hours.
5. If every hour has either no shortfall or the maximum hourly battery discharge before total discharge reaches 4 hours, the remaining discharge is split evenly between the 4 and 10 PM hours that have not reached maximum hourly discharge.

Table 14 shows the hourly profile used for solar, wind and battery resources. While the solar and wind profile remains unchanged throughout the analysis, the battery profile changes to reduce the shortfalls. Therefore, the battery profile in Table 14 is for 2024 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 2024 thus, the battery profile is optimized to reduce the shortfalls as much as possible across all critical hours.

Table 14: Wind, Solar, and Battery Hourly Profile

Wind				Solar				Battery			
Time PDT	**Jul**	**Aug**	**Sep**	**Time PDT**	**Jul**	**Aug**	**Sep**	**Time PDT**	**Jul**	**Aug**	**Sep**
4PM-5PM	0.38	0.28	0.15	4PM-5PM	0.73	0.72	0.65	4PM-5PM	0.39	0.48	0.35
5PM-6PM	0.44	0.33	0.19	5PM-6PM	0.60	0.56	0.43	5PM-6PM	0.42	0.51	0.66
6PM-7PM	0.48	0.38	0.22	6PM-7PM	0.35	0.27	0.11	6PM-7PM	0.77	0.85	1.00
7PM-8PM	0.51	0.42	0.28	7PM-8PM	0.07	0.03	0.00	7PM-8PM	1.00	0.98	1.00
8PM-9PM	0.52	0.48	0.30	8PM-9PM	0.00	0.00	0.00	8PM-9PM	0.84	0.71	0.64
9PM-10PM	0.54	0.51	0.32	9PM-10PM	0.00	0.00	0.00	9PM-10PM	0.58	0.48	0.35

Source: CEC staff with 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 in

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.

2024 Summer

Using data sourced on January 2024 for the summer 2024 stack analysis,

Figure 6 shows that there is enough supply to meet the demand in all conditions but a 2022 equivalent event, assuming that there no supply delays or additional outages/extreme events impacting available generation. This September scenario assumes that all projected resources come online by August 31st, 2024, to meet the projected demand in September. The identified need for contingencies in the 2022 equivalent event is 90 MW and occurs in hour 18.

While the 90 MW shortfall, under average conditions, can be covered by state-procured contingency resources, any combination of new resource build delays, elevated outages, demand variability beyond the average, or transmission loss could move the system from a manageable scenario to a greater shortfall scenario under an extreme event.

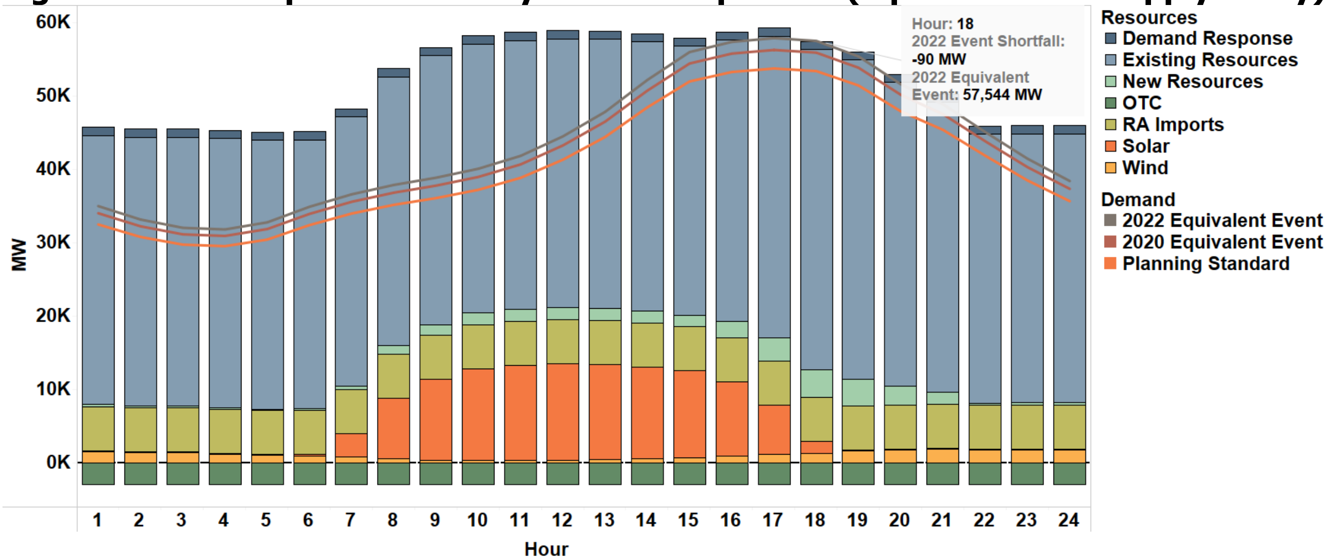
Under a 20 percent resource build delay, Figure 7 shows that there could be an 800 MW max shortfall in hour 18, if a 2022 equivalent heat event were to happen this summer. Beyond the hour of max shortfall, the surrounding hours of 17 and 19 would also be tight under extreme events. Figure 8 shows how a 40 percent resource build delay with elevated outages and high demand variability, as observed in the September 2022 equivalent heat event can increase the shortfalls in September 2024. Figure 8 shows that, under extreme scenarios, there could be a 1,600 MW max shortfall in September hour 18.

Table 15: 2024 July-September Stack Values based on Hour 18

Resources	July	August	September
Demand Response	1,121	1,140	1,116
Existing	42,378	43,110	43,556
Hydro NQC*	7,022	6,900	6,440
New Batteries MW**	3,003	3,155	3,327
New Resources	3,006	3,461	3,758
RA Imports	6,000	6,000	6,000
Solar	5,428	4,202	1,643
Wind	3,045	2,422	1,382

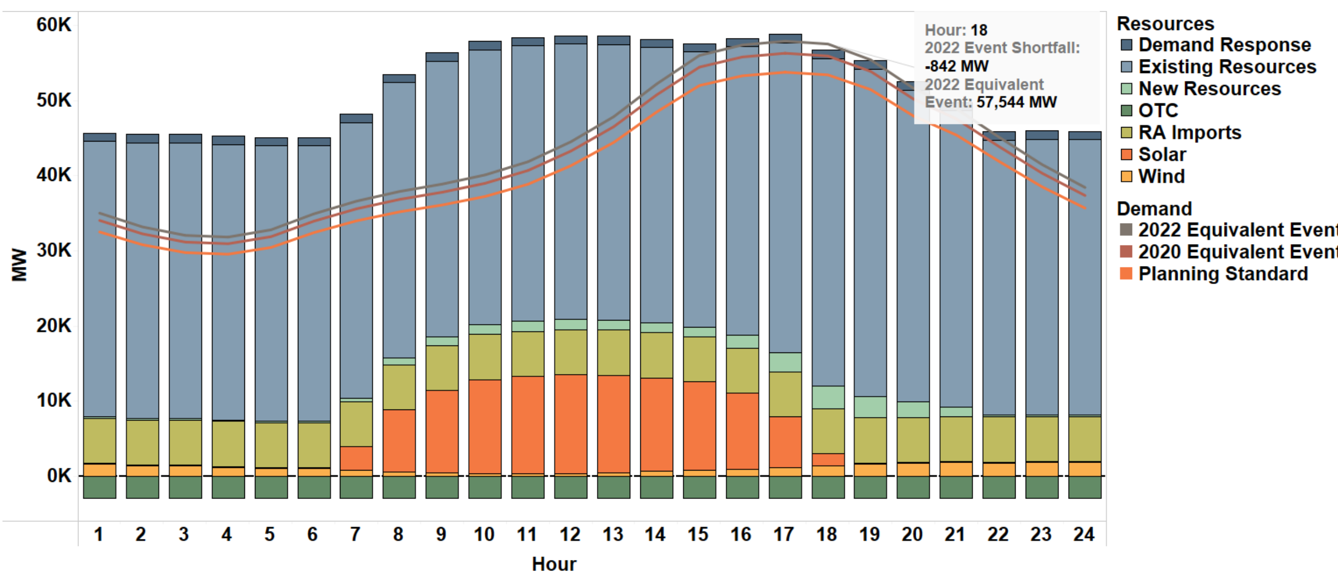
*NQC value for hydro is already include in row labeled “Existing”
**value is already included in row labeled “New Resources”
Source: CEC with California ISO and CPUC data

Figure 6: 2024 September Hourly Stack Comparison (0 percent New Supply Delay)



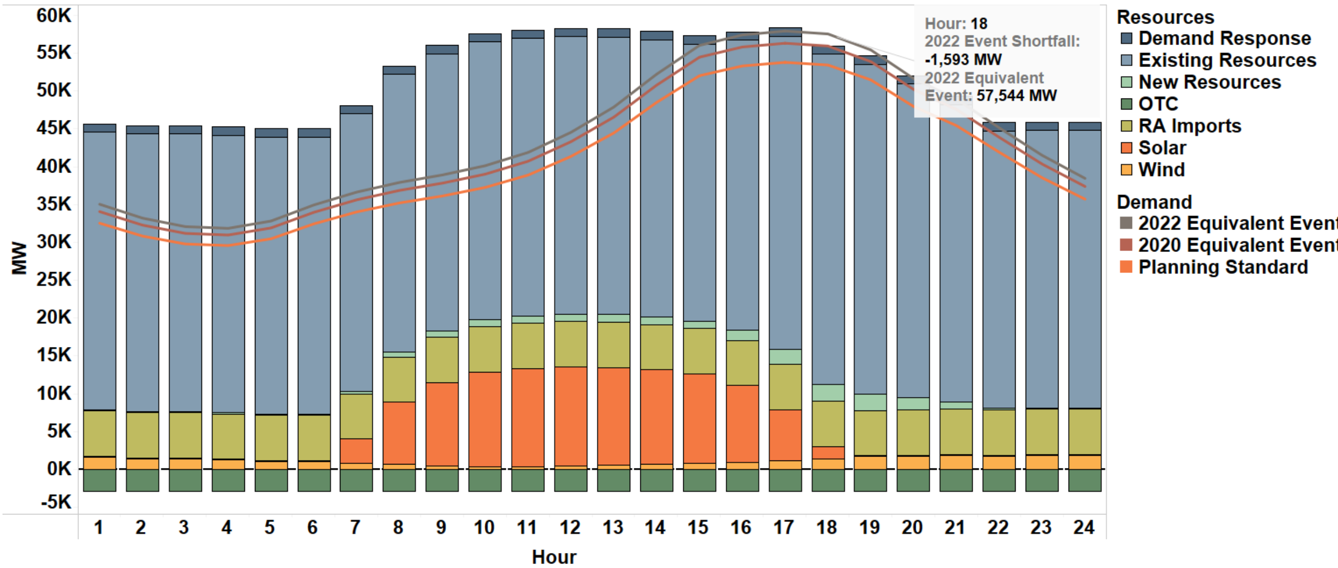
Source: CEC staff with California ISO data

Figure 7: 2024 September Hourly Stack Comparison (20 percent New Supply Delay)



Source: CEC staff with California ISO data

Figure 8: 2024 September Hourly Stack Comparison (40 percent New Supply Delay)



Source: CEC staff with California ISO data

5-Year Overview (2025 to 2029):

Within the 5-year horizon, the planning standard resulted in surplus in all delay scenarios. When analyzing the supply and demand in summer extreme events, a small shortfall of 180 MW was observed in 2025 under a 2022 equivalent event and 40 percent delay to the resource build. Note that this scenario does not include a coincident event of transmission capacity loss from a wildfire.

Compared to prior stack analyses, there is a reduction in the amount of contingency resources needed over the next five years, in part because of the extension of DCPP, which is now counted as part of the supply stack until 2031, new resources coming online, and lower projected demand forecast in the 2023 Final CED.

10-Year Overview: This section explores the supply and demand balance in the 10-year horizon using 0, 20, and 40 percent delay adjustments to the ordered procurement supply in each year. The annual supply was compared to a planning standard of a 17 percent reserve margin. Then, the annual supply was compared to more extreme events, which were defined as a 2020 equivalent event and a 2022 equivalent event.

Under the planning standard, the ordered procurement resulted in surplus for all delay scenarios until 2032, which is due to no new supply being ordered after 2028 and the gradual demand increase year to year. The max shortfall observed in the planning standard was 2400 MW in 2034 (Figure 9).

Figure 9: 10-Year Stack Analysis

		Year									
	Delay Percent	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
2022 Equivalent Event	40	-179	606	620	390	0	0	-732	-2,216	-4,501	-6,374
	20	317	852	772	561	0	0	-732	-2,216	-4,501	-6,374
	0	813	1,097	925	733	0	0	-732	-2,216	-4,501	-6,374
2020 Equivalent Event	40	1,434	1,911	1,951	1,750	1,398	1,383	630	-803	-3,035	-4,852
	20	1,930	2,158	2,103	1,922	1,398	1,383	630	-803	-3,035	-4,852
	0	2,143	2,403	2,256	2,094	1,398	1,383	630	-803	-3,035	-4,852
Planning Standard	40	3,969	3,963	4,044	3,889	3,594	3,557	2,769	1,417	-733	-2,461
	20	4,106	4,209	4,196	4,060	3,594	3,557	2,769	1,417	-733	-2,461
	0	4,151	4,454	4,349	4,232	3,594	3,557	2,769	1,417	-733	-2,461

Red - Shortfall
Green - Surplus

Shortfall Magnitude (MW)
-6,374 4,454

Source: CEC staff with CPUC data

When considering the impacts of extreme events, the outlook becomes worse with 2034 having a 6,400 MW shortfall, in a 2022 equivalent event. It is important to note that DCPP Units are now planned to be fully retired beginning in 2031, with one unit retired beginning in 2030.

Another element to consider in addition to extreme events, which can worsen an already strained power grid, is loss of transmission. More specifically, this analysis briefly explored the impact of losing 4,000 MW of capacity, as a result of fire causing transmission lines to be de-energized. The effects of losing 4,000 MW in the 10-year horizon leads to shortfalls in most years, including shortfalls under traditional planning standard starting in 2030, and greatly increase the shortfalls in the most extreme events, up to 10,400 MW.

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 were focused on the implications of solar dropping off in late evening and hydroelectric resources losing efficacy in a drought.[28] In 2022, the CEC extended the time horizon for the stack analysis to assess planning priorities out to 2026. The analysis

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28 Tanghetti, Angela, Liz Gill, and Lana Wong. 2021. *2022 Summer Stack Analysis*. California Energy Commission. Publication Number: CEC-200-2021-006. https://efiling.energy.ca.gov/GetDocument.aspx?tn=239806.

was extended in part to assess implications of OTC retirements.[29] Hourly shapes for wind, batteries, and new resources were required, to better represent the limitations of resources the state will be dependent on in the future. Other changes included the use of a generic number for imports rather than recent RA values, the elimination of the drought derate, and a reliance on procurement orders rather than contracts to estimate future resources.

For summer 2024, initial projections are based on California ISO New Resource Implementation Queue data. This dataset allows the CEC stack analysis to more accurately evaluate the need for contingency resources based on resources coming online above what has been ordered and contracted.

Table 16 below shows the evolution of the stack analysis during 7-8PM September, which is the maximum shortfall hour in each of these analyses. Table 16 includes the average and elevated reserve margins and shortfall numbers at the same hour.

Table 16: Summer Stack Releases from September 2021 to January 2024

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
Jan 2024	2024	17%	0	26%	90

*Extreme shortfall 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

Senate Bill 1020 requires the CPUC, CEC, and State Air Resources Board, to annually issue a joint reliability progress report that reviews system and local reliability within the context of that state policy described above, with a particular focus on summer reliability, identifies challenges and gaps, if any, 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.

29 Craig, Hannah. 2022. *Summer Stack Analysis for 2022-2026*. California Energy Commission. Publication Number: CEC-200-2021-006-REV. https://efiling.energy.ca.gov/GetDocument.aspx?tn=244116.

California ISO 2024 Local Capacity Area Technical Study

To satisfy the requirements of SB 1020, this report draws on insights from the California ISO 2024 Local Capacity Area study[30]. 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[31] (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 (RMR) 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 2024 Local Capacity Technical (LCT) Study align closely with those utilized in the 2007-2023 LCT Studies, ensuring consistency and comparability. However, the 2024 LCT study used the CEC's 2022 IEPR demand forecast[32]. Since the release of the 2024 LCT study, a new CEC IEPR demand forecast has been released. Overall, the capacity required for LCR has seen a decrease of approximately 3369 MW or 13.2 percent from 2023 to 2024.

The specific areas with decreased LCR needs include Humboldt, attributed to a load forecast decrease; Big Creek/Ventura, influenced by lower flows from Sylmar due to the outage of Sylmar Bank E (LADWP-owned transformer at Sylmar substation); Kern, impacted by increase in resources NQC values; and LA Basin and San Diego/Imperial Valley, owing to the implementation of new transmission projects. Conversely, LCR needs have increased in Fresno due to a load forecast increase; Bay Area and North Coast/North Bay, reflecting a different load pattern; Sierra, influenced by changes in NQC values; and Stockton, attributed to the availability of new resources.

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30 California Independent System Operator, "Final 2024 Local Capacity Technical Report," available via February 27, 2024, https://www.caiso.com/InitiativeDocuments/Final-2024-Local-Capacity-Technical-Report.pdf

31 California Independent System Operator, "Final Study Manual: 2024 Local Capacity Requirements," via, https://www.caiso.com/InitiativeDocuments/FinalStudyManual-2024LocalCapacityRequirements.pdf

32 California Energy Commission, "California's Energy Future: Integrated Energy Policy Report (IEPR) - 2022," via https://efiling.energy.ca.gov/GetDocument.aspx?tn=248666&DocumentContentId=83163

Figure 10: 2024 Final LCR Needs

	August Qualifying Capacity				Capacity Available at Peak	2024 LCR Need
Local Area Name	QF/ Muni (MW)	Non-Solar (MW)	Solar (MW)	Total (MW)	Total (MW)	Capacity Needed
Humboldt	0	176	0	**176**	**176**	**133**
North Coast/ North Bay	137	852	0	**989**	**989**	**983**
Sierra	1197	686	0	**1883**	**1883**	**1212***
Stockton	130	613	7	**750**	**743**	**750***
Greater Bay	617	7327	4	**7948**	**7944**	**7329***
Greater Fresno	206	2740	181	**3127**	**2946**	**2028***
Kern	10	374	43	**427**	**384**	**427***
Big Creek/ Ventura	406	3446	265	**4117**	**4117**	**1971**
LA Basin	1179	7164	10	**8353**	**8353**	**4413**
San Diego/ Imperial Valley	2	5204	182	**5388**	**5206**	**2834**
Total	**3884**	**28582**	**692**	**33158**	**32741**	**22080**

Source: California ISO

The results of the 2024 LCT Study are forwarded to the CPUC for consideration in its 2024 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 2025 LCT study in May 2024.

CHAPTER 7: Mid- to Long-Term Probabilistic Reliability Assessment

In this section CPUC and CEC staff include probabilistic reliability analyses, to build on the deterministic analysis in Chapter 6. Such probabilistic studies, centered around the loss of load expectation (LOLE) reliability standard of 0.1 days per year, are the industry standard for reliability planning.

The CEC and CPUC use a similar probabilistic framework studying a range of weather years and forced outage outcomes in different modeling software (SERVM for CPUC and PLEXOS for CEC). The studies also align on major assumptions like import levels, baseline resource capacities, and expansion resource levels. The dual perspective allows for more scenarios to be evaluated and provides robustness to scenarios in common by showing the results do not depend on modeling software or other minor assumptions.

CPUC Studies – Context & Purpose

CPUC Energy Division staff (CPUC staff) conducts probabilistic reliability studies of the California ISO system on an annual cadence for the purpose of supporting the CPUC to transmit portfolios for the Transmission Planning Process. In conjunction with these annual studies staff also conducts studies for other purposes in the IRP and RA proceedings.

For CPUC staff's contribution to this Joint Reliability Assessment, staff drew on recent studies[33] published alongside the October 5, 2023, Administrative Law Judge (ALJ) Ruling "Seeking Comment on Proposed 2023 Preferred System Plan and Transmission Planning Process Portfolios".

Among the range of studies performed for the Ruling, the following are most relevant for this Joint Reliability Assessment:

- Baseline-Only (2024-28) - determine reliability of existing system baseline (existing resources, less announced retirements, and adding contracted in-development resources)
- Baseline plus Ordered Procurement (2024-28) - informative for 2023 PSP development and determining need for additional procurement action; also informative for comparing to 2023 SB 846 studies and California ISO's 2023 Summer Assessment
- Potential/proposed 2023 PSP Portfolio (2026, 2030, 2035) - determine reliability and emissions of 25 MMT Core portfolio; this is similar to the portfolio adopted by the CPUC

33 California Public Utilities Commission, "PSP Ruling Reliability and Emissions Analysis Slides," available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/psp-ruling-reliability-and-emissions-analysis-slides_20231004.pdf

on February 15, 2024 as the 2023 PSP and 2024-25 Transmission Planning Portfolio base case.

CPUC Studies - Model

CPUC staff used the modeling tool Strategic Energy Risk Valuation Model (SERVM) to conduct stochastic reliability simulations. The SERVM model is a loss-of-load probability model maintained by CPUC staff that is capable of simulating system conditions under twenty-three years of historical weather conditions applied to loads and resource availability across the California ISO and its neighbors. SERVM uses historical relationships between temperature, load, wind, and solar output to simulate system operations across thousands of Monte Carlo draws that also consider stochastic generator outages and twenty-three years of hydroelectric power availability.

CPUC Studies - Key Assumptions

CPUC staff studies reported here build on those used to model the Base Portfolio for use in California ISO's 2023-24 Transmission Planning Process, released by the CPUC in February 2023. For details of the updates refer to 2023 Inputs & Assumptions documents.[34]

The following updates to Baseline resources were made:

- Staff updated its Baseline resource list, which involved reconciling data from multiple sources (California ISO, Western Electricity Coordinating Council (WECC), Energy Information Administration (EIA), CPUC, CEC) and developing a common list of units for both SERVM and RESOLVE – the capacity expansion model the CPUC uses in its IRP process – models
- California ISO Master Generating Capability (MGC) List as of 1/2023 (updated online status of in development resources and reconciled with newly online units)
- 11/1/2022 LSE IRP compliance filings
- 1/2023 NQC List
- WECC Anchor Dataset 2032
- Unit operating data updated from 2018 to 2022 from latest California ISO MasterFile
- OTC steam units assumed to go offline by 2023 and DCPP assumed to go offline in 2024/25, and no further retirements

The resulting list of Baseline resources is available in the SERVM-centric Generator List[35]

34 California Public Utilities Commission, "2022 IRP Cycle Events and Materials," available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

35 California Public Utilities Commission, "System Reliability Modeling Datasets 2023," available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/system-reliability-modeling-datasets-2023

Resources – Baseline-only Studies

Baseline-only studies are designed to determine the current reliability situation based on A) planned retirements, and B) Baseline existing and in-development resources coming online over the near to mid-term years (2024-2028).

Modeled resources include only Baseline resources (online and/or in-development) and excludes "Planned New/Review" resources from the 11/2022 LSE IRP filings.

- "In-development" resources are those from 11/2022 LSE IRP filings, not online but with executed contracts as at 8/1/2022. Baseline-only resources include a portion of ordered procurement (e.g., MTR) but not all of it.
- Baseline includes approximately 5,000 MW NQC of in-development MTR procurement.
- Baseline does not include the remaining approximately 10,500 MW NQC ordered that is not yet in-development.

Table 17: Baseline-Only Nameplate MW, by study year

Unit Category	2024	2025	2026	2027	2028
Storage	12,385	12,845	12,946	12,946	12,946
Battery storage	8,614	9,074	9,175	9,175	9,175
Hybrid_BattStorage	882	882	882	882	882
Paired_BattStorage	1,407	1,407	1,407	1,407	1,407
PSH	1,483	1,483	1,483	1,483	1,483
Gas	27,814	27,814	27,833	27,833	27,833
CC	17,528	17,528	17,528	17,528	17,528
Cogen	1,823	1,823	1,842	1,842	1,842
CT	8,204	8,204	8,204	8,204	8,204
ICE	259	259	259	259	259
Biomass	669	669	669	669	669
Coal (Intermountain)	480	0	0	0	0
DR	2,404	2,230	2,381	2,238	2,242
Geothermal	1,290	1,290	1,330	1,351	1,384
Hydro	5,374	5,374	5,374	5,374	5,374
Nuclear	2,935	1,785	635	635	635
Solar	19,948	19,948	19,948	19,948	19,948
Solar_1Axis	11,799	11,799	11,799	11,799	11,799
Solar_2Axis	13	13	13	13	13
Solar_Fixed	6,228	6,228	6,228	6,228	6,228
Solar_Thermal	997	997	997	997	997
Hybrid_Solar_1Axis	711	711	711	711	711
Hybrid_Solar_Fixed	200	200	200	200	200
Wind	7,713	7,789	7,789	7,789	7,789
Total MW	**81,013**	**79,745**	**78,906**	**78,783**	**78,821**

Source: 2023 Proposed Preferred System Plan Reliability and Emissions Analysis

Resources - Baseline plus Ordered Procurement

For assumptions of resource amounts in this study, see CPUC Studies - Results section below.

Resources - Proposed 2023 PSP

To support PSP development CPUC staff used RESOLVE, a capacity expansion model, to produce two portfolio types:

- Core: Baseline resources with 11/2022 LSE plans "forced in," plus RESOLVE selecting additional resources and/or gas retention to meet policy and reliability constraints.
- Least-Cost: Baseline resources only, plus RESOLVE selecting a cost-optimal portfolio of new carbon-free resources/gas retention to meet policy and reliability constraints.

This report focuses on the 25 MMT Core portfolio.

Figure 11: Aggregated LSE Plans by Resource Type - 25 MMT (MW)

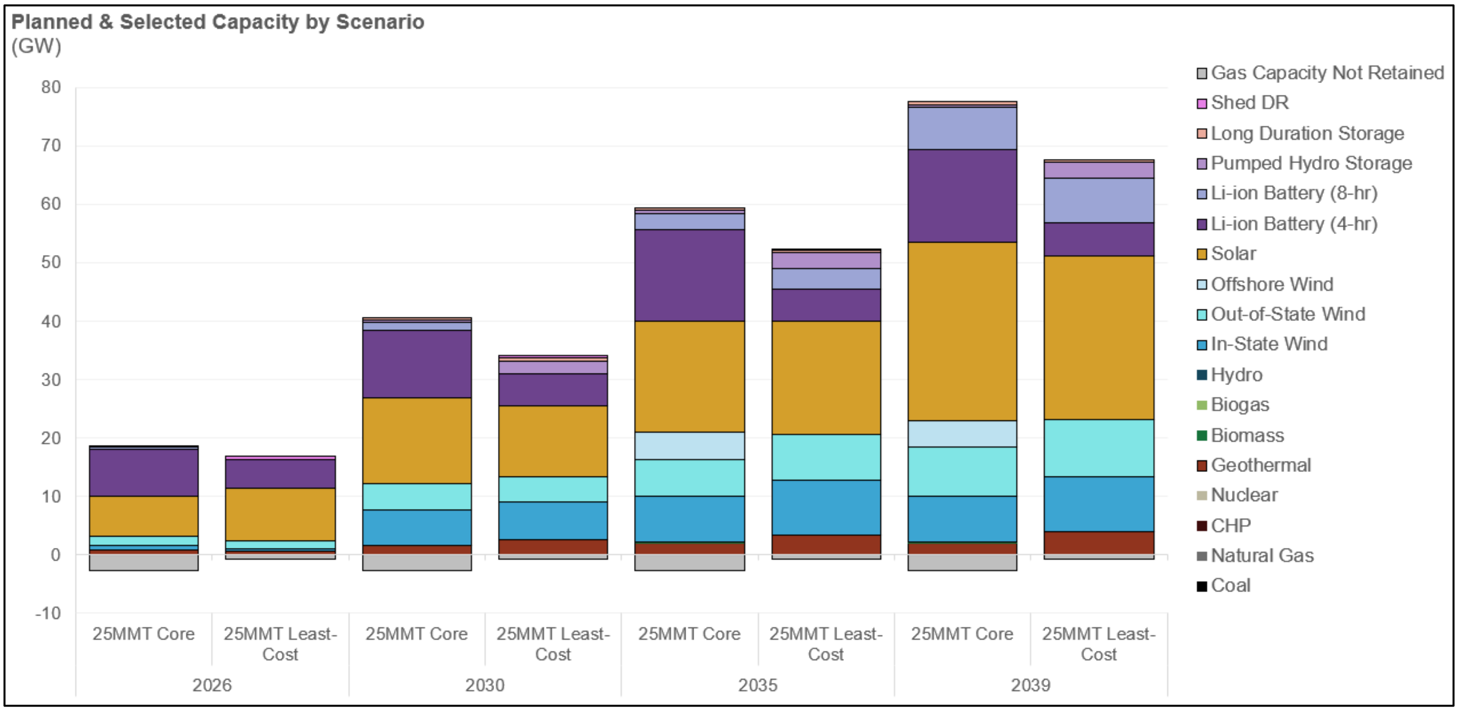
- Staff aggregated all resources in LSE plans: existing contracted, existing planned to be contracted, in-development, under review, and planned new
- "Additional retired" refers to individual thermal units removed if not specifically quantified as contracted or planned for resources in LSE Plans
  - Removed units are CC, Cogen, and CT categories

Year	2024	2026		2030		2035	
Gas retention	No unannounced retirements	No unannounced retirements	-3364 MW add'l retired	No unannounced retirements	-5515 MW add'l retired	No unannounced retirements	-5903 MW add'l retired
25 MMT by 2035 LSE Plan							
Battery Storage	12,613	17,689	17,689	22,287	22,287	28,216	28,216
Biomass	713	794	794	873	853	864	852
BTMPV	16,827	19,252	19,252	24,492	24,492	31,023	31,023
CC	17,536	17,536	15,747	17,536	14,280	17,536	13,898
Coal	480	-	-	-	-	-	-
Cogen	1,938	1,957	1,185	1,957	557	940	551
CT	8,204	8,204	7,401	8,204	7,345	8,204	7,345
DR	2,822	2,804	2,804	2,851	2,851	2,851	2,851
Geothermal	1,440	2,393	2,393	2,826	2,826	2,922	2,922
Hydro	5,995	6,003	6,003	6,003	6,003	6,003	6,003
ICE	259	259	259	259	259	259	259
Nuclear	2,935	635	635	635	635	635	635
OffshoreWind	-	-	-	1,580	1,580	4,531	4,531
PSH	1,483	1,940	1,940	1,952	1,952	1,952	1,952
Solar	20,304	24,577	24,577	34,249	34,215	38,456	38,422
Steam	-	-	-	-	-	-	-
Wind	8,038	10,284	10,284	15,002	15,002	15,736	15,736

Source: 2023 Proposed Preferred System Plan Reliability and Emissions Analysis

The RESOLVE portfolio was translated into SERVM inputs and simulated in SERVM for 2026, 2030, and 2035 to determine LOLE and GHG emissions. Staff compared RESOLVE and SERVM GHG emissions and made further calibrations to align the models' outputs where possible. Some calibration adjustments led to reruns of RESOLVE, refining a portfolio, while others were adjustments to SERVM's characterization of a portfolio.

Figure 12: RESOLVE Modeled Capacity Additions



Source: [2023 Proposed Preferred System Plan Reliability and Emissions Analysis]

CPUC Studies – Other Inputs and Assumptions

Cogen/Biomass/Biogas/Geothermal operating constraints: monthly "capmax" and "capmin" were calculated to reflect historical operations and minimum dispatch observed in the California ISO bidding database, as follows:

- Average production during peak managed demand used as capmax (equivalent to resource NQC)
- The Max of Day Ahead Market scheduled and Real Time Market bid level was used to determine capmin
- Cold and hot startup profiles updated
- Imposing monthly capmax and capmin for Cogen/Geothermal/Biomass/Biogas units distorted heat rate curves. Corrected by using a single point heat rate curve matching the average heat rate from California ISO Masterfile data.

Hydro inputs: CPUC staff refreshed 1998-2020 hydroelectric data and methodology as follows:

- Hourly and monthly data collected from EIA, California ISO, Bonneville Power Administration (BPA)
- Detrended monthly data used to develop dispatch model
- Emergency hydro capacity added
- Made hydro years independent of weather years in model stochastic inputs. This increases the number of hydro-demand combinations.

External region inputs (imports and exports):

- California ISO summer evening hour simultaneous imports capped at 4,000 MW, otherwise approximately 11 GW in all other hours
- Load and resource balance for external regions were tuned to approximate a 0.1 LOLE reliability level for all study years. Regions external to California were limited to adjacent areas in Pacific Northwest and Southwest.

Load inputs:

SERVM uses 23 years of historical weather data and associated load shapes and is tuned so that the median peak load is equivalent to the relevant IEPR scenario's median peak load.

The following input updates were made to those used to model the Base Portfolio for use in California ISO's 2023-24 Transmission Planning Process, released by the CPUC in February 2023:

- Updated to 2022 IEPR Planning Peak and Energy Forecast data
- Hourly demand modifier profiles (additional achievable energy efficiency, additional achievable fuel substitution, additional achievable transportation electrification, EVs, time of use rates, BTM storage) drawn directly from the 2022 IEPR
- BTM PV annual energy by IEPR Planning Area drawn from the 2022 IEPR and used to calibrate SERVM's BTM PV hourly profiles
- California ISO coincident managed peak modeled in SERVM calibrated to match with IEPR

Cost input updates:

The following input updates were made to those used to model the Base Portfolio for use in California ISO's 2023-24 Transmission Planning Process, released by the CPUC in February 2023:

- Gas prices and gas delivery hubs (in 2022 dollars) updated from CEC's draft 2023 NAMGas model
- Carbon prices derived from the GHG price forecast included with 2022 IEPR in 2022
- Transmission import hurdle rates escalated from 2018 to 2022
- Unit variable costs updated from 2018 to 2022 from latest California ISO MasterFile

CPUC Studies - Results

Baseline-only

Staff tuned/quantified the amount of "Perfect Capacity" (i PCAP) required to be added to the Baseline to achieve approximately 0.1 days/year LOLE in each year from 2024 through 2028. The term PCAP can be used interchangeably with ELCC MW.

Results are informative to Baseline + Ordered Procurement analysis (next section).

Figure 13: Baseline-Only Studies: Reliability Results Before and After Tuning with Perfect Capacity

Annual Reliability Metrics		Before tuning to 0.1 LOLE					After tuning to 0.1 LOLE				
Metric	Units	2024	2025	2026	2027	2028	2024	2025	2026	2027	2028
LOLE	days/year	0.43	2.04	1.92	3.14	4.10	0.12	0.10	0.10	0.10	0.10
EUE	MWh	997	12,193	12,386	23,873	29,769	187	198	191	156	188
LOLH	hours/year	0.85	5.35	5.22	9.29	11.88	0.19	0.19	0.17	0.14	0.16
LOLH/LOLE (average length of outage)	hours/day	2.0	2.6	2.7	3.0	2.9	1.6	1.9	1.6	1.4	1.5
Normalized EUE (EUE / total electric demand)	percent	0.00040%	0.00486%	0.00487%	0.0093%	0.01143%	0.00008%	0.00008%	0.00007%	0.00006%	0.00007%
PCAP added to return to 0.1 LOLE	MW	N/A	N/A	N/A	N/A	N/A	2,200	6,000	5,800	8,000	8,000

Source: 2023 Proposed Preferred System Plan Reliability and Emissions Analysis

Baseline plus Ordered Procurement

After analyzing the MTR incremental capacity in the 2023 PSP Baseline (~5,000 Perfect Capacity MW NQC by 2026), an estimation of the sufficiency of the MTR order was performed via the following method:

- Calculate the cumulative MTR MW targets
- Subtract the MTR incremental procurement in the 2023 PSP Baseline to calculate the "remaining MTR procurement"
- Compare the remaining MTR procurement to the calculated PCAP shortfall from the Baseline-only studies, to calculate any potential MTR "gap"
    - If PCAP shortfall is greater than remaining MTR procurement, there is a gap
    - If PCAP shortfall is less than remaining MTR procurement, there is a surplus.

Initial runs were conducted using the PSP Baseline thermal retention assumptions (no gas retires beyond the modeled attrition of the OTC plants at the end of 2023).

Table 18: MTR Sufficiency Analysis

	(Units = Perfect capacity MW)	2023	2024	2025	2026	2027	2028	Notes
A	MTR Ordered Procurement (annual)	2,000	6,000	1,500	2,000	2,000	2,000	
B	MTR Ordered Procurement (cumulative)	2,000	8,000	9,500	11,500	13,500	15,500	Cumulative sum of A
C	MTR Incremental Procurement (in PSP Baseline)	2,896	4,219	4,578	4,700	4,719	4,750	Source: Staff analysis of RESOLVE-centric Generator List
D	Remaining MTR Procurement (above PSP baseline)	-896	3,781	4,922	6,800	8,781	10,750	B – C
E	SERVM PCAP Shortfall (using PSP Baseline)	n/a	2,200	6,000	5,800	8,000	8,000	Direct SERVM model outputs
F	MTR Gap: MTR ordered relative to SERVM shortfall	n/a	-1,581	1,078	-1,000	-781	-2,750	E – D

Source: 2023 Proposed Preferred System Plan Reliability and Emissions Analysis

Probabilistic reliability studies directly consider the following risks: load and generation variability, load forecast error, and generator forced outages. CPUC staff also studied risks including further gas retirements, import availability, climate change impact risks, and project development delays. The results are available in the materials published alongside the October 5, 2023, ALJ Ruling.[36]

Proposed 2023 PSP

Table 19: Reliability and GHG Results – 25 MMT Core

25 MMT CORE	2026		2030		2035		
Category	**RESOLVE**	**SERVM**	**RESOLVE**	**SERVM**	**RESOLVE**	**SERVM**	**Units**
LOLE		0.009		0.002		0.053	days/year
California ISO emitting generation	59,691	73,118	33,506	45,946	16,773	39,674	GWh
California ISO generator emissions	23.4	30.1	13.2	19.5	6.6	16.2	MMT CO2
Unspecified imports	16,130	9,347	15,085	12,089	21,641	9,810	GWh
Unspecified imports emissions	6.9	4.0	6.5	5.2	9.3	4.2	MMT CO2
California ISO BTM CHP emissions	4.8	4.8	4.7	4.7	4.4	4.4	MMT CO2
Total California ISO emissions	35.1	38.9	24.3	29.4	20.3	24.8	MMT CO2
Difference in GHG emissions		3.8		5.1		4.5	MMT CO2

Source: 2023 Proposed Preferred System Plan Reliability and Emissions Analysis

In summary, the results for the proposed 2023 PSP show:

- The portfolio is very reliable (vs. 0.1 days/yr LOLE) in 2026, 2030, and 2035.
- This is driven by the MTR procurement orders, LSEs' plans showing procurement above MTR requirements, and RESOLVE's selection of additional GHG-free resources and retention of more gas plants than LSE plans assumed.
- SERVM analysis validates RESOLVE results that showed the planning reserve margin (PRM) not binding in 2026, 2030, or 2035 (indicating that system reliability should be less than 0.1 LOLE).

These results are discussed further below, alongside the CEC staff's study results.

CEC Studies - Purpose and Scenarios

The CEC did a probabilistic assessment of the mid-term reliability outlook from 2024 to 2035, under the supply forecast in the proposed 2023 PSP released via CPUC ALJ Ruling in October 2023. The goal of this analysis is to determine if the state is meeting the reliability standard of 1 day of outage in 10 years (0.1 LOLE). Three different classes of potential reliability issues

36 At slides 20-26: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/psp-ruling-reliability-and-emissions-analysis-slides_20231004.pdf

were evaluated: whether imports fail to meet expectations, whether future resource additions fail to meet expectations, and whether DCPP does not remain in-service. Generally, the PSP contains sufficient resources that the 0.1 LOLE standard is met even under extreme scenarios.

Table 20: Probabilistic Scenarios

Import Contingencies	Supply Contingencies	DCPP
Statewide Limit 12,450 MW, California ISO Limit 5,425 MW	40% PSP resources delayed 1 year	In-service
No Imports, California ISO Limit 6,900 MW	40% PSP resources reduced	Retired
N/A	Full PSP	N/A

Source: CEC Staff

CEC Studies – Model

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

CEC Studies - Key Assumptions

The model used demand and renewable shapes for 15 weather years representing 2007 to 2021, and the years are weather-linked (for example, 2015 demand is always modeled with 2015 wind and solar shapes). The demand shapes are the same as used in CPUC staff modeling for the PSP and involves scaling weather years to the demand forecast 1 in 2 peak and then adding load modifiers (like energy efficiency, transportation electrification, etc.) on top. Load modifiers are not varied by weather year. A shape for the 2021 weather year was not available so the demand shape for 2013 is modeled alongside 2021 wind and solar.

The model is California-centric, meaning power plants for the state are modeled in detail, but areas outside the state are represented as generic imports. Imports for the state are constrained to 12,450 MW in all hours of the day and imports for the California ISO are constrained to 4,000 MW of generic imports and 1,542 MW of pseudo-tied resources during peak (hours 15 to 21). The state import constraint was determined by an analysis of interchange data reported to EIA 930, and the 12,450 MW number represents the 95th percentile of historic imports reported. Outage results are reported for the state as a whole, though the California ISO region experiences the vast majority of outages.

Below is a table describing the data sources for the major inputs to the model.

Table 21: Model Input Sources

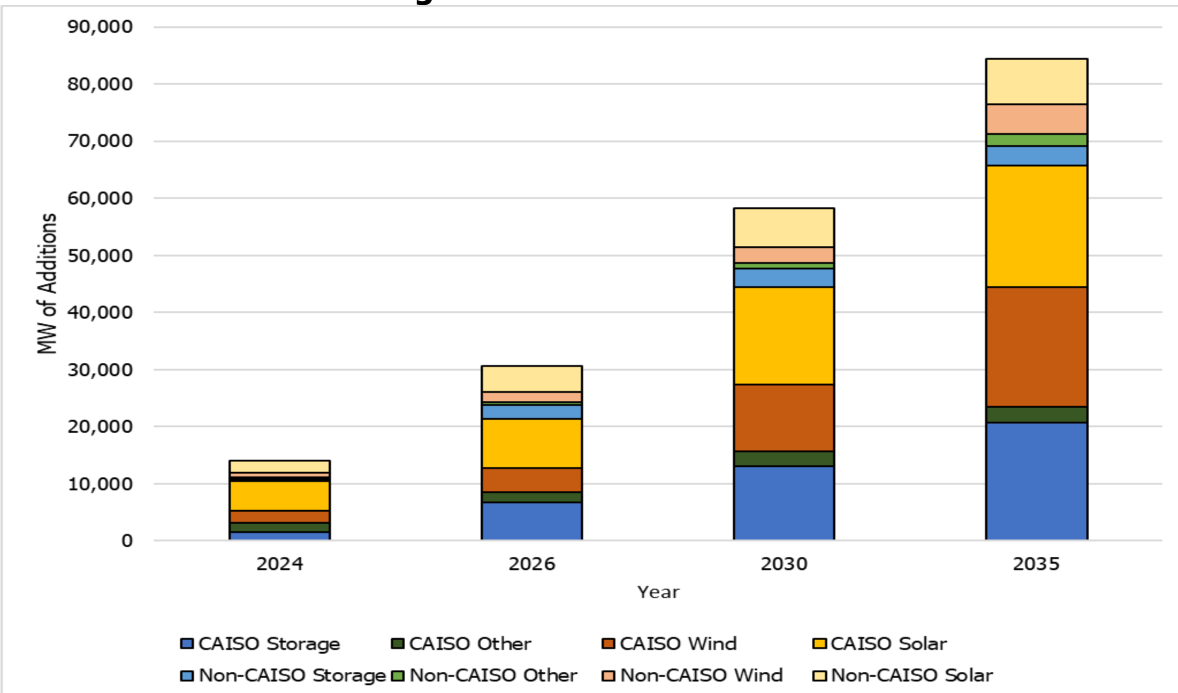
Model Input	Data Source	Comments
Demand Shapes	CPUC Weather-Sensitive Load	Based on 2022 CED vintage
Forced Outage Rates	NERC GADS	N/A
Plant Capacities	QFER	2022 QFER Data reported in 2023
Plant Heat Rates	QFER	N/A
Expansion Resources	Proposed CPUC 2023 Preferred System Plan	Released in October 2023, Core Scenario (25 MMT by 2035)
Solar Shapes	NREL PV WATTS	N/A
Wind Shapes, 2007-2014	NREL WTK	Calibrated using actual monthly generation totals reported to EIA 923
Wind Shapes 2015-2021	Actual Generation Data from California ISO Subpoena	Aggregated by Wind Resource Area
Transmission Line Ratings	WECC Path Limits	N/A
Hydro Monthly Energy Budget	EIA 923	N/A
OTC Retirements	California ISO Announced Retirements and Mothball List	Assumed to be retired in 2023 for all scenarios

Source: CEC Staff

All expansion resources for both California ISO and non-California ISO regions were sourced from the CPUC proposed 2023 PSP released in October 2023[37]. Below is a graph of the expansion resources included in the default forecast of the model. Figure 14 includes both contracted (baseline) resources and generic additions.

37 CPUC. (2023). Portfolios and Modeling Assumptions for the 2023-2024 Transmission Planning Process. Available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-powerprocurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfoliosand-modeling-assumptions-for-the-2023-2024-transmission-planning-process

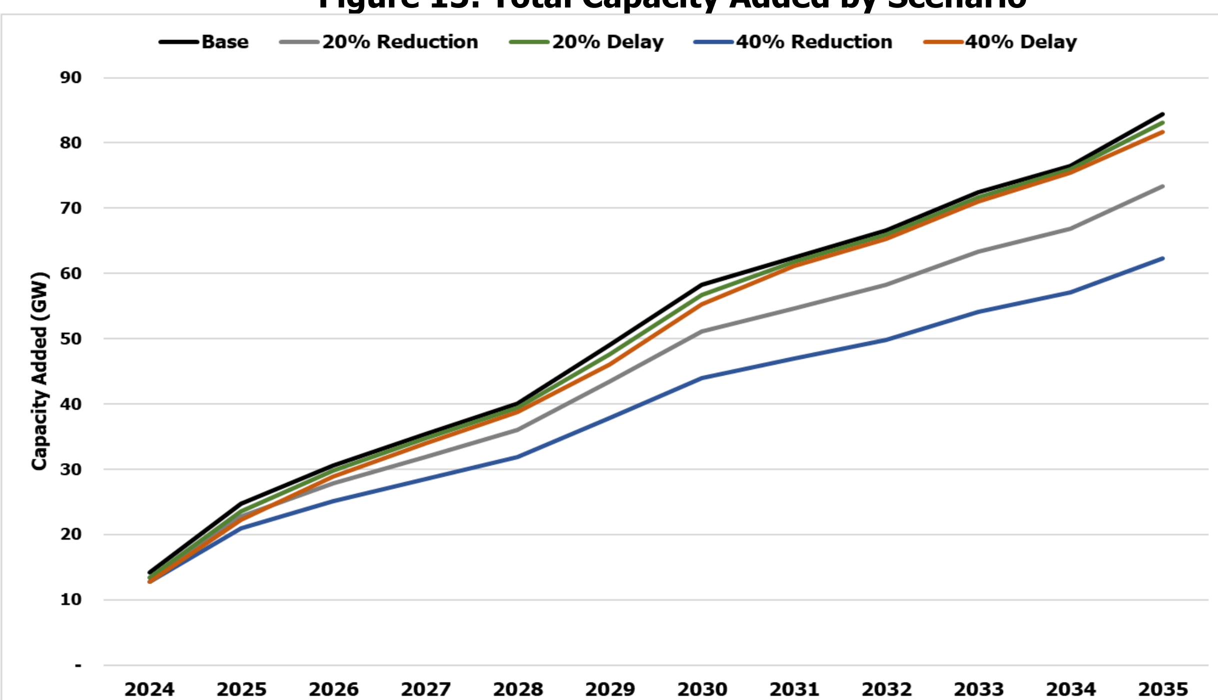
Figure 14: Total Resource Additions



Source: CEC Staff

The delay and reduction scenarios were applied only to the generic non-contracted resources, which make up the bulk of the capacity added in later years. The delays were for only one year and don't affect the forecast substantially. However, the reductions, in total resource additions, significantly impacted reliability.

Figure 15: Total Capacity Added by Scenario



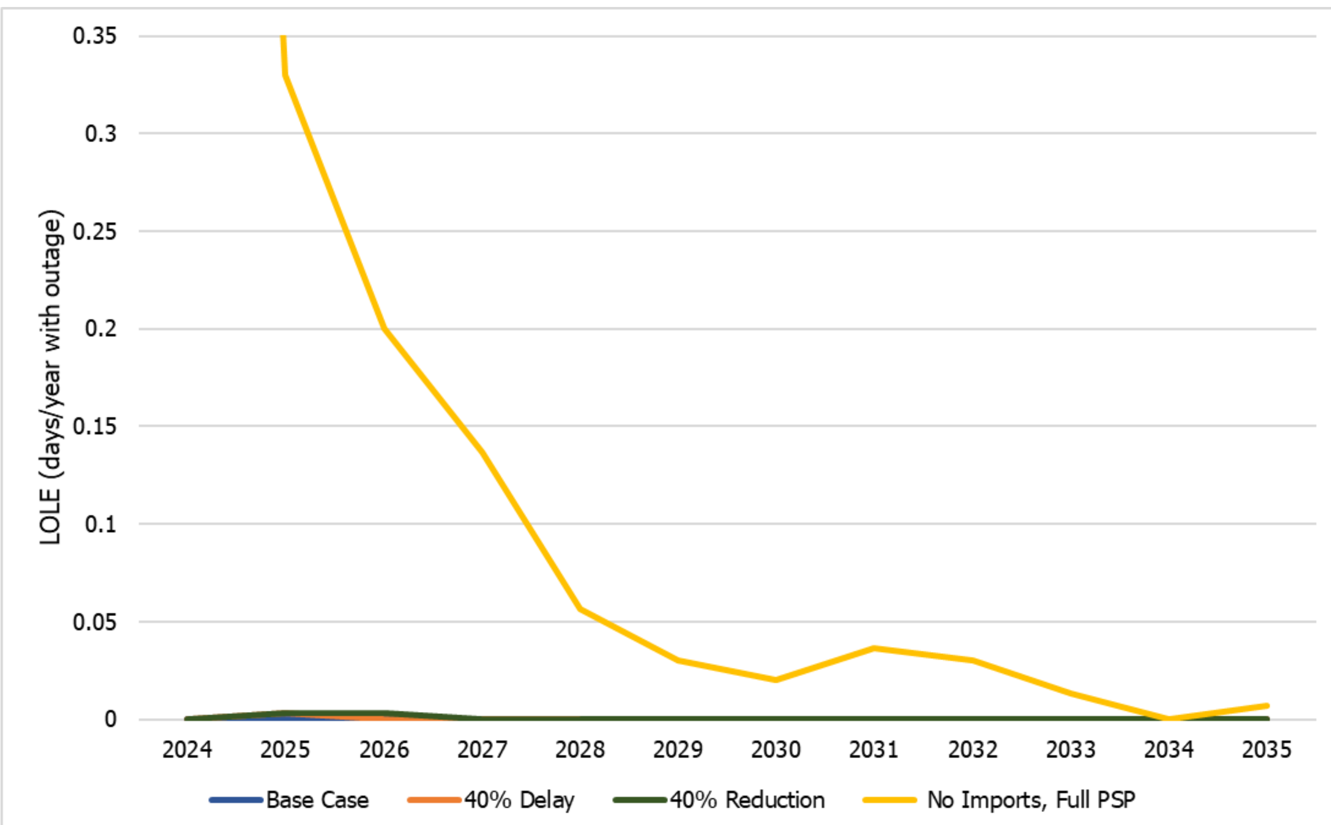
Source: Telos Consulting Staffs

CEC Studies - Results

Proposed 2023 PSP with DCPP In-Service

Modeling indicates that the probability of outages with DCPP in-service is minimal. Cases run with the full PSP and default import assumptions experienced zero outages in any year across 300 samples. With 40 percent of the resource additions of the PSP reduced, the LOLE rises to 0.0033 in 2025 and 2026, but remains two orders of magnitude below the 0.1 LOLE target. Even with statewide imports reduced to zero in any hour, the portfolio meets the 0.1 LOLE standard after 2028. It should be noted, however, that the DCPP extension was primarily intended to provide additional buffer against extreme events, such as those experienced in 2020 and 2022. These results in combination with the deterministic results in Chapter 6 indicate that the DCPP has provided this additional needed buffer.

Figure 16: LOLE with DCPP In-Service

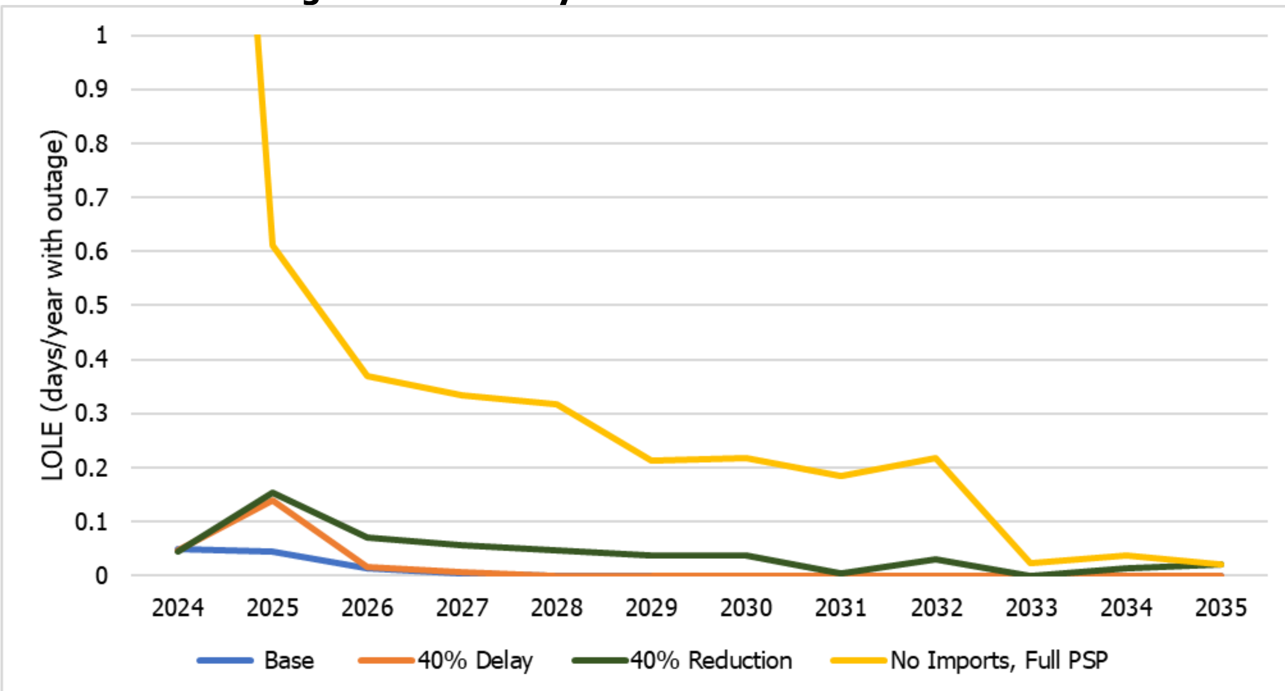


Source: CEC Staff

Proposed 2023 PSP with DCPP Out of Service

Modeling indicates that the full PSP portfolio is extremely reliable under default import conditions in every year, as is to be expected since the DCPP can not be included for the purposes of integrated resource planning. Both the 40 percent Delay and the 40 percent Reduction scenarios do not meet the 0.1 LOLE standard in 2025 without DCPP. The full PSP with statewide imports reduced to zero in all hours of the day does not meet the 0.1 LOLE standard until 2033.

Figure 17: LOLE by Year with DCPP Out of Service



Source: CEC Staff

Baseline-Only Cases

The CEC performed a baseline-only study from 2024 to 2035. The goal of this analysis is to determine the amount of perfect capacity needed to meet the 0.1 LOLE standard. This study used the default California ISO import assumptions (4,000 MW unspecified + 1,500 MW specified) and assumed DCPP was retired.

The perfect capacity need is estimated through looking at the outage patterns. By looking at the 30th largest outage of 300 samples, the perfect capacity can be estimated for what would be required to reduce the number of outages to 30 days in 300 years, corresponding to the 1 day in 10 year standard.

Generally, modeling indicates that large and increasing amounts of perfect capacity are needed beyond resources already contracted.

Table 22: Reliability Statistics for Baseline-Only Analysis

	LOLE (day/yr)	Perfect Capacity Requirement (MW)	Expected Unserved Energy (MWh/yr)
2024	0	0	0
2025	0.18	1,599	690
2026	0.2167	3,070	1,140
2027	0.2467	6,670	2,015
2028	0.32	10,218	3,688
2029	0.3833	11,238	5,368
2030	0.5033	13,366	7,538
2031	0.6333	14,581	10,871
2032	0.89	16,036	15,468
2033	2.1967	15,792	27,824
2034	3.3167	17,643	47,512
2035	4.91	19,466	78,428

Source: CEC Staff

Discussion

The CPUC staff and CEC staff analyses present distinct approaches to evaluating California's power system reliability, each offering valuable insights within their specific scope. The CPUC staff analysis centers on annual probabilistic reliability studies using the SERVM model. This approach provides a detailed examination of the California ISO system's current and future reliability, focusing on the adequacy of existing resources and the potential need for additional procurement actions.

The CEC analysis adopts a broader statewide perspective in assessing the reliability outlook from 2024 to 2035. Utilizing PLEXOS, the CEC explores a range of scenarios, including delays and reductions in resource additions, import contingencies, and the impact of DCPP retirement.

CPUC staff and CEC staff have been working towards alignment on assumptions since the CEC began probabilistic modeling in 2021. For this study, new and existing resources, the demand shapes, and the import assumptions are very similar between the CEC staff and CPUC staff models. The primary differences are in the choice of model (SERVM vs PLEXOS) and the renewable profiles, which are created by each agency independently through similar methods.

Having two models provides more robustness. When the models agree, it suggests that results do not depend on quirks in modeling software or other minor modeling choices. Alignment on demand and resource levels suggests any differences observed are not due to easily quantified things, such as one study including more imports.

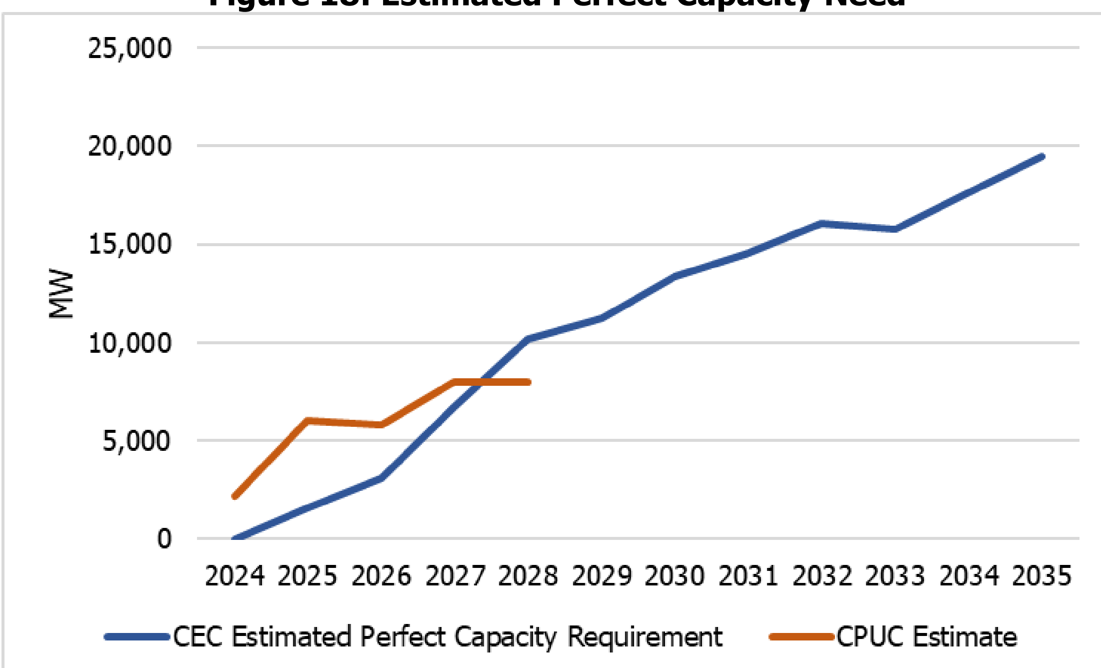
Baseline-Only

The CPUC staff performed baseline-only studies for near- to mid-term study years 2024 through 2028. Staff identified whether the system as-is was reliable (LOLE equal to or below 0.1) and if unreliable, how much PCAP (i.e. ELCC MW) must be added to return the system to adequate reliability. The Baseline includes some capacity that is contracted but not yet online, mainly in 2024; however, staff notes that contracts for new resources entered after the 8/1/2022 cutoff date for LSEs' 11/1/2022 plans are excluded from the Baseline studied here.

For the CPUC staff study, all study years were initially found to be unreliable but were returned to reliability after adding PCAP ranging from 2,200 MW in 2024 to 8,000 MW in 2028. While the perfect capacity need is smaller in 2024, due to the 2024 contracted additions in the Baseline, the need grows significantly in 2025 and beyond as DCPP retires.

The CEC found no additional generic capacity was needed to meet reliability in 2024, and the perfect capacity need for 2025 was below that of the 2,200 MW of DCPP modeled as retired in that year, meaning reliability goals could be achievable without any additional generic resources until 2026. In 2026 and beyond, large and increasing capacity is required to meet a 0.1 LOLE. The CPUC staff and CEC staff estimates are within 2,000 MW of each other for each year.

Figure 18: Estimated Perfect Capacity Need



Source: CEC Staff

Proposed 2023 PSP

CPUC staff and CEC staff studies are consistent, showing that the proposed 2023 PSP portfolio is over-reliable through 2035. This is likely due to the MTR orders, CPUC-jurisdictional LSEs' plans showing procurement beyond MTR requirements, and RESOLVE's selection of additional GHG-free resources - and retention of more gas plants - than LSE plans assumed.

The primary reliability risks for the state looking forward are that things will not go as planned: that 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 state will be reliable even if resources come in 40% below the resource additions of the proposed 2023 PSP, but the state will continue to depend on imports well into the 2030s.

CHAPTER 8: Recommendations

The recommendations are organized into the categories addressing the key reliability challenges of ensuring planning, scaling resources and protecting the grid during extreme events.

2024 Updated Recommendations

Continue to Improve of Situational Awareness

- The California ISO, CEC, and CPUC should continue to work to increase the transparency of transmission network upgrades and interconnection processes to assist communities, LSEs, and developers in their planning. This work includes examining the alignment of the California ISO transmission planning processes, CPUC integrated resource planning, and LSE procurement activities to ensure use of best available information for decision-making.
- 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 CEC and other relevant state agencies should continue to monitor energy storage performance and safety, continue to improve safe frameworks to ensure both public safety and reliability. Higher outage rates, lengths of outages etc., than assumed in the modeling could have significant impacts on the modeling results and should be carefully considered as more data becomes available. It would be prudent to retain current levels of capacity supporting peak and net peak demands until energy storage performance has been further demonstrated.

Improve Planning Assumptions

- The CEC, CPUC and California ISO should continue to develop a common approach to incorporating climate change into system planning, including a set of climate scenarios to be considered. This approach builds off EPIC research that will support incorporating climate change into the demand forecast and anticipated EPIC research to quantify benefits of resilience planning and consider the needs of tribes, disadvantaged, and low-income communities in such planning.
- Continue to evaluate whether changes to the PRM and other reliability planning metrics are warranted for all load serving entities in the state based on climate change impacts and increasing variable generation resources.
- The CEC and CPUC should continue to collaborate to develop alignment of electric demand shapes across historical weather years, including any climate adjustments, to ensure alignment on the weather conditions used in reliability analysis. This also enables assessing the expected frequency of the extreme load conditions that occurred in September 2022.

Also, the agencies should also create scenarios around hydroelectric vulnerability in the event of drought.

- The CEC and CPUC should continue to coordinate their baseline update efforts to ensure that future studies consistently measure the impacts of ordered procurement against a common baseline such that procurement orders, planning portfolios, and other drivers of procurement can be more easily cross-walked and compared when running different modeling scenarios.

Realization of Procurement

- The CEC, CPUC and California ISO should continue to implement the terms of the new MOU signed by the three entities in December 2022.
- Continue to refine a structure that better integrates statewide electricity planning and local land use planning and permitting that recognizes the scale and pace at which clean energy projects and supporting infrastructure must be built.
- Consider policy mechanisms and project viability measures that incentivize LSE selection of projects toward areas where interconnection and transmission network upgrades have a viable and timely path forward.
- Ensure consistency and expertise across all jurisdictions in siting Battery Energy Storage Systems (battery storage) and addressing operational issues related to battery storage.
- Scale Demand-Side Resources.
- The CEC and CPUC should continue to collaborate to restructure the state’s demand response program to shift to an approach that will take advantage of flexible-demand appliances and the market-informed demand automation server (MIDAS).
- Continue coordination efforts between the agencies and proceedings to maximize the opportunities with demand response and demand flexibility.

Research, Development, and Demonstration

- The CEC should continue to invest EPIC funds in applied research that supports integration of climate considerations into electric planning, operations, and technology investment. This integration includes improving characterization of the climate conditions under which the grid must reliably operate now and in the future, improving supply and demand forecasting over a range of timescales, and improving situational awareness and forecasting of wildfire-related risks to grid operations. The CEC should coordinate any such research that is funded through EPIC with the LSE EPIC administrators, and encourage their participation in CEC EPIC projects, particularly those related to improving grid operations for reliability and resiliency. This research, in turn, informs technology and policy options that can contribute to grid reliability in the context of decarbonization.
- The CEC should continue to invest EPIC funds in increasing customer load flexibility in the residential, commercial, and industrial sectors to support grid reliability. This work includes overcoming technical, market, and regulatory, barriers that reduce adoption and use of load-flexible technologies. It also includes improving the suite of technology options available to energy users to allow them to better adapt their load to system conditions as flexible power consumers.

Continue to Develop Extreme Event Resources

- The CEC and CPUC should continue to coordinate with DWR, California ISO, other balancing authority areas, and stakeholders to develop and expand extreme event resources to support the grid during extreme conditions.

APPENDIX A: Acronyms and Abbreviations

AB – Assembly Bill

BA – balancing authority

BAA – balancing authority area

BANC – Balancing Authority of Northern California

California ISO – California Independent System Operator

CCA – community choice aggregators

CEC – California Energy Commission

CPUC – California Public Utilities Commission

DCPP – Diablo Canyon Power Plant

DEBA – Distributed Electricity Backup Assets

DOE – U.S. Department of Energy

DOF – California Department of Finance

DR – demand response

DSGS – Demand-Side Grid Support

EEA - Energy Emergency Alert

ELCC – effective load-carrying capacity

ELRP – Emergency Load Reduction Program

EPIC – Electric Program Investment Charge

ESSRRP – Electricity Supply Strategic Reliability Reserve Program

EV – electric vehicle

GHG – greenhouse gas

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

GW – gigawatts

GWh – gigawatt-hours

IEPR – Integrated Energy Policy Report

IID – Imperial Irrigation District

IOU – investor-owned utility

IRP – integrated resource plan

LADWP – Los Angeles Department of Water and Power

LLT – long-lead time

LOLE – Loss of Load Expectation

LSE – load-serving entity

MIDAS – market-informed demand automation server

MMT – million metric tons

MTR – mid-term reliability

MW – megawatt

MWh - megawatt-hour

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

PTO – participating transmission owner

PV - photovoltaic

RA – resource adequacy

Reliability Planning Assessment – Joint Agency Reliability Planning Assessment

Roseville – City of Roseville

RPS – Renewables Portfolio Standard

SB – Senate Bill

SCE – Southern California Edison

SDG&E – San Diego Gas & Electric

Shasta Lake – City of Shasta Lake

SMUD – Sacramento Municipal Utility District

SRR – Strategic Reliability Reserve

ESSRRF – Electricity Supply Strategic Reliability Reserve Fund

TAC – Transmission Access Charge

TED – Tracking Energy Development

TPP – Transmission Planning Process

APPENDIX B: Glossary

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

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

Balancing authority

A balancing authority is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time. Balancing authorities in California include 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)

The Balancing Authority of Northern California 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.

Community Choice Aggregation (CCA)

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

Demand response (DR)

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

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

Distributed energy resources (DER)

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

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

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

Extreme 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)

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.

Integrated Resource Planning (IRP)

The CPUC's Integrated Resource Planning (IRP) process is an "umbrella" planning proceeding to consider all of its electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply. The proceeding is also the Commission's primary venue for implementation of the Senate Bill 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)

Investor-owned utilities (IOUs) provide transmission and distribution services to all electric customers in their service territory. The utilities also provide generation service for "bundled" customers, while "unbundled" customers receive electric generation service from an alternate provider, such as a Community Choice Aggregator (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." For more information see the California Independent System Operator's Web page.

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 day 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)

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

Planning reserve margin (PRM)

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

Publicly owned utility (POU)

Publicly owned utilities (POUs), or Municipal Utilities, are controlled by a citizen-elected governing board and utilizes public financing. These municipal utilities own generation, transmission and distribution assets. In contrast to ds, 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 Renewables Portfolio Standard, also referred to as RPS, is a program that sets continuously escalating renewable energy procurement requirements for California's load-serving entities. The generation must be procured from RPS-certified facilities (which include solar, wind, geothermal, biomass, biomethane derived from landfill and/or digester, small hydroelectric, and fuel cells using renewable fuel and/or qualifying hydrogen gas). More information can be found at the CEC Renewables Portfolio Standard web page and the CPUC RPS Web page.

Resource adequacy (RA)

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

Scenario

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

Time-dependent electricity rates

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

Transmission Planning Process (TPP)

The California 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.