California State Assembly

UTILITIES AND ENERGY

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Upon Adjournment of Governmental Organization Committee
1021 O Street, Room 1100

OVERSIGHT HEARING

Electric Reliability

The North American electric grid is the world's largest connected machine, linking everyone's lights through a continuous, monumental network of wires carrying electricity at the speed of light. For the Western Interconnection alone, that network stretches from Baja California to the furthest reaches of British Columbia, and from the Pacific to over the Rockies. There are a multitude of operators and regulators responsible for tending to the safe and reliable functioning of this infrastructure. The reliable operation of California's portion of this system is a core responsibility of the state's energy regulators, grid operators, and power providers. Most days of the year, that reliability is achieved without drama or incident. But for a few hours on a select number of days each year that system is tested when demand for electricity peaks and supply is tight. Those are the days for which significant time, effort, and expense are spent to prepare, as existing law requires.[1] The level of that preparation is the subject of this oversight hearing.

In a recent reminder of the significance of electric reliability, on April 28, 2025, the people of Spain and Portugal experienced unplanned, cascading electricity blackouts. In the middle of the day, the Spanish grid operator, Red Eléctrica, experienced volatility in the frequency at which the electric grid operates that was far greater than normal. Shortly thereafter, approximately 15,000 megawatts (MWs) of supply was lost in a matter of seconds, the equivalent of ~60% of Spanish electricity load.[2] Unplanned blackouts ensued. The electric grid of Portugal, while managed by a separate grid operator,[3] is heavily interconnected with and reliant upon that of Spain. Residents of both countries experienced severe disruption, although power was largely restored to customers across Portugal the same evening; and across Spain by the following

1 Including, but not limited to, Public Utilities Code §380.
2 Millard, Rachel, et al., "How did Spain's electricity grid collapse?" Financial Times, April 29, 2025, https://www.ft.com/content/e922cda3-801d-40df-8455-5d3aeae34288
3 REN - Redes Energéticas Nacionais.

morning.[4] Investigations by Spanish and European officials are underway into the cause or, perhaps more likely, multiple causes of this event. But initial review reportedly includes a focus on insufficient inertia on the grid at the time of the incident; inertia provides stability to the grid when there is an imbalance between supply and demand.[5]

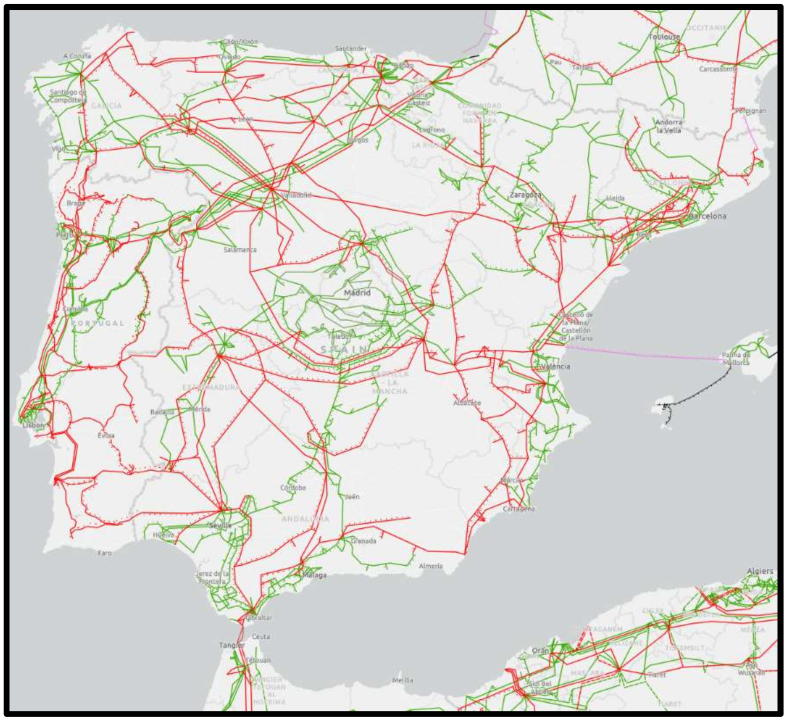

Figure 1: The transmission system on the Iberian Peninsula, showing the high level of interconnection from Spain to Portugal, but with few connections to the north and south.[6]

Key: red indicates 380-400kV transmission lines; green indicates 220kV transmission lines.

It is also worth noting that despite the significant integration between the Spanish and Portuguese electricity grids, connections between Spain and the rest of Europe are only 3,000 MWs, limited compared to the scale of this event.[7] The electric grid of France did not experience the same challenges; indeed, the French and Moroccan grid operators assisted Red Eléctrica in restoring power on the Iberian Peninsula.[8] For an electric grid that is usually seen as being reliable, this event shows how crucial reliability is and how important the ties between neighboring grids are, for better or worse.

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4 Sharrock, David, and Johnson, Ian, "Spain's electricity grid operator rules out cyber attack as cause of blackout," Financial Times, April 28, 2025, https://www.ft.com/content/1363127b-014e-4f30-ab5d-38f76d640274

5 Inertia is kinetic energy that is stored in heavy, spinning components of the electric grid, including at hydroelectric and thermal power plants, as well as spinning flywheels. It is used to balance fluctuations in the grid instantaneously, including to maintain a steady frequency and, thus, reliability.

6 European Network of Transmission System Operators for Electricity (ENTSO-E), https://www.entsoe.eu/data/map/

7 Red Eléctrica, https://www.ree.es/en/ecological-transition/electricity-interconnections

8 Kirby, Paul, "How Spain powered back to life from unprecedented national blackout," BBC News, April 29, 2025, https://www.bbc.com/news/articles/c175ykvjxyeo

Findings:

- Short-term = adequate. Electricity supply for summer 2025 appears to meet demand under normal circumstances, and also appears adequate under extraordinary circumstances using existing contingency resources.
- Mid-term to long-term = uncertain. Expiring state policies and resource retirements, the volatile effect of federal tariffs, and the expected growth of energy demand all materially contribute to that uncertainty.
- Complexity is growing. The reliability outlook, and state policies around it, continue to grow more complex. The extent to which this complexity serves a clear purpose, which cannot be simplified, is not always evident.

The purpose of this hearing is twofold: first, to hear from the state energy entities[9] on the readiness of the California electric grid to operate reliably during summer 2025; and second, to consider some of the broader issues affecting the mid- and long-term reliability outlook.

Who are the players?

Load serving entities (LSEs): These are the entities that serve retail electricity demand, including electric corporations /investor-owned utilities (e.g. PG&E), community choice aggregators (CCAs; e.g. Sonoma Clean Power), and electric service providers (ESPs; e.g. NRG Energy). These are regulated by the California Public Utilities Commission (CPUC).

Local publicly-owned utilities (POUs): These are also entities that serve retail electricity, but as vertically-integrated monopoly utilities (e.g. NCPA, LADWP). These are regulated by a local board and, in part, the California Energy Commission.

Wholesale generators: These are the entities that develop and/or operate power plant and energy storage facilities, excluding most hydroelectric and nuclear facilities, and sell both energy and capacity to load serving entities and POUs. These are regulated by the Federal Energy Regulatory Commission (FERC).

Balancing authorities: These are grid operators that manage the stable operation of the bulk side of the electric grid (e.g. LADWP, BANC), including electricity generation and transmission that is owned and maintained by others. They may also administer electricity markets for buyers and sellers of power. There are a number of California balancing authorities, but the California Independent System Operator (CAISO) is by far the largest. These are regulated by FERC.

Regulators: The CPUC is responsible for regulation pursuant to state law, including Resource Adequacy. FERC is responsible for regulation pursuant to federal law. Reliability standards are the responsibility of the North American Electric Reliability Corporation (NERC); and in the Western Interconnection of which California is part, the Western Electricity Coordinating Council (WECC), at NERC's direction.

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[9] For clarity, 'state energy entities' is a simplified term used in this paper to refer to the CPUC, CEC, CAISO, and DWR; noting that the CAISO is a non-profit public benefit corporation that has a functional role supporting the state, but is not a state entity. CAISO is overseen by a board of governors and is regulated by FERC.

Part 1 – Recent History: Responding to the Rotating Outages of 2020 and Lessons Learned.
California experienced two extreme heat waves in 2020 that stressed the electric grid. One of those heat waves resulted in rotating outages by the CAISO between 6 to 9 PM on August 14 and 15, 2020, due to an approximately 500 megawatt shortfall.[10] Controlled, rotating outages were called by CAISO and used as an emergency reliability measure to minimize disruption and avoid a wider, uncontrolled outage. This event was the first time since the early 2000s that rotating outages were necessary to maintain reliability of the system.

Broadly, there were three categories of issues that led to the 2020 rotating outages:[11]

- Issue 1. Resource planning, both in the forecasting of demand and the setting of procurement targets to meet that demand, fell behind the pace of real-world change. In substantive part, this was driven by the climate changing faster than backward-looking data could predict, which also led to an underestimation in the amount of procurement necessary to meet demand.
- Issue 2. Delays in bringing new resources online.
- Issue 3. Unintended consequences in market design that overestimated supply.

The state energy entities' responses to these causes were multifold, including significant revisions to forecasting methods and setting mid-term procurement requirements to respond to issue 1, various permitting and process reforms in response to issue 2, and updates to market design in response to issue 3. For more on the 2020 events and the response to them, see the background papers from this Committee's prior electric reliability hearings.[12]

Reliability: What's the standard? A common industry standard for electric reliability is that the expected number of days in which demand exceeds supply is 1 day in 10 years, or a '1 in 10' Loss of Load Expectation.[13] Given that a decade contains more than 3,650 days, this is a high standard. However, it is important to note there is complexity in how this is assessed and modelled, as well as how inputs are calculated (e.g. what the effective versus theoretical capacity of a resource is). As a result, different entities can assess the likelihood of a 1 in 10 differently.

Reliability standards applied – the Planning Reserve Margin(s) and Resource Adequacy: Since the mid 2000's, Resource Adequacy has the state's key reliability policy framework. The CPUC uses the CEC demand forecast to assess what capacity LSEs must procure to on a system, flexible, and local Resource Adequacy area basis. One key reliability factor within Resource Adequacy is the planning reserve margin (PRM), which is stacked on top of the demand forecast to account for the inherent variability of any system, acting as a buffer for fluctuations in demand, generation, and weather, among other factors. One can think of the PRM as extra sandbags stacked just in case the water rises higher than expected, even if the forecast says the river will not flood. In the same way, the electric PRM adds extra generation capacity on top of

[10] CAISO, CPUC, and CEC; "Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm"; October 6, 2020; http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf

[11] CAISO, CEC, CPUC; FINAL Root Cause Analysis: Mid-August 2020 Extreme Heat Wave; January 13, 2021; https://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

[12] Assembly Utilities & Energy Committee, *Oversight Hearing: Reliability in the Near and Mid Term*, May 8, 2024; *Annual Oversight Hearing: Focus on Grid Reliability and 2023 Summer Readiness*, May 16, 2023; *Joint Informational Hearing – 2030: Vision: Mid-term Actions Needed for the Energy Transition,* November 14, 2022; *Oversight Hearing – Summer Readiness: Ensuring Reliability Since the August 2020 Outages*, May 18, 2021; *Oversight Hearing – August 14th and 15th, 2020, Electricity Outages*, October 12, 2020; https://autl.assembly.ca.gov/archives-0

[13] A 1 in 10 is also described as a 0.1 Loss of Load Expectation; those terms are interchangeable. The PRM is then stacked on top of this demand forecast.

expected demand to protect against unexpected surges or outages. The PRM is composed of three numbers that add up to the overall margin: (1) an operating reserve, (2) a margin for unexpected outages, and (3) a margin for demand variability.

As part of the Resource Adequacy program, the CPUC annually determines the PRM for its jurisdictional LSEs, which is approximately three-quarters of all statewide demand. This is not just a compliance obligation for LSEs to meet, it is a capacity buffer, as well as a metric upon which other reliability tools are tied. That includes tools available to the CAISO when there is insufficient capacity to meet the PRM.[14]

In 2021, the CPUC also created an *effective* PRM that is greater than the actual PRM. With the intent of increasing feasible capacity procurement, the effective PRM was a requirement specifically on electrical corporations to procure additional resources above the PRM. The costs of this are allocated to all benefiting customers. Failure to meet the effective PRM is not penalized in the same manner as when a load serving entity fails to meet the PRM.

Table 1: Planning Reserve Margin for CPUC-jurisdictional LSEs.

	2020	**2021**	**2022**	**2023**	**2024**	**2025**
PRM	15%	15%	15%	16%[15]	17%[16]	17%
Effective PRM	N/A	17.5%[17]	20 to 22.5%[18]	20 to 22.5%[19]	~22.5%[20]	~22.5%

The balancing act the CPUC sought to strike in applying, and later continuing, an effective planning reserve requirement on top of the normal planning reserve requirement is the value versus the cost of that additional capacity. An effective PRM increases the PRM substantively but not officially, and only to the extent electrical corporations can meet it. In other words, the effective PRM is more aspirational, less binding, to the electrical corporations; and the CAISO cannot use the effective PRM as the benchmark for any of its backstop authority. The CPUC has expressed concern about delays and costs of new resource development when considering a higher PRM;[21] and indeed, anecdotal reports about Resource Adequacy market prices in the years before 2025 indicated a sellers' market with high prices for buyers. But the need for an effective PRM at all indicates the PRM is lower than theoretically warranted. Regardless, its existence is an additional complication to the reliability framework.

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14 The capacity procurement mechanism allows the CAISO to solicit additional capacity on a monthly basis to meet demand when planning reserve margin is not met. The CAISO also, separately, has the authority to retain a power plant that would otherwise retire on a year-ahead basis through a reliability must run contract.

15 D.22-06-050, *Decision Adopting Local Capacity Obligations for 2023-2025, Flexible Capacity Obligations for 2023, and Reform Track Framework*, issued June 24, 2022, in Rulemaking 21-10-002.

16 D.22-06-050, in Rulemaking 21-10-002. Affirmed in D.23-06-029, *Decision Adopting Local Capacity Obligations for 2024-2026, Flexible Capacity Obligations for 2024, and Program Refinements*, issued July 5, 2023, in Rulemaking 21-10-002.

17 D.21-03-056, *Decision directing PG&E, SCE, and SDG&E to take actions to prepare for potential extreme weather in the summers of 2021 and 2022*, issued March 26, 2021, in Rulemaking 20-11-003.

18 D.21-12-015, *Phase 2 Decision Directing PG&E, SCE, and SDG&E to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023*, issued December 6, 2021, in Rulemaking 20-11-003.

19 D.21-12-015, in Rulemaking 20-11-003.

20 Technically, set as a requirement of 1,700 to 3,200 MWs, which translates to ~22.5%, D.23-06-029, in Rulemaking 21-10-002.

21 D.23-06-029, in Rulemaking 21-10-002.

The remaining approximately one-quarter of power providers in California operate outside the CPUC's Resource Adequacy program and are not subject to the PRMs set by the CPUC. Local publicly owned utilities set their own PRMs, outside of direct state oversight. It has been unclear from a state level whether local publicly owned utilities' PRMs during past periods of grid strain have been adequate. But in 2023, the CEC analyzed publicly owned utilities' performance against a typical 15% PRM. Of the 38 utilities reviewed in 2023, 7 were deficient and 4 did not report data; but the remaining 27 exceeded a 15% PRM. The number of utilities deficient in this assessment increased to 9 in the CEC's 2024 estimate.[22] While some of these utilities may have planned to contract for additional resources, imports, or make spot market transactions to account for any deficiency, the 2024 assessment does suggest a potential recurring tightness in some publicly owned utilities' portfolios. By nature of the electricity system and marketplace, tightness in one power provider's portfolio can affect others elsewhere, increasing system deficiencies.

<u>Part 2 – The Electric Reliability Outlook for Summer 2025.</u> In recent memory, California's overall electricity demand has peaked each year in the summer. This is not the case for every western state, and this may change for California too in the future. But the state's energy entities can project with effective certainty that the highest peak of electricity demand this year will again occur during the summer period.

Summer 2024 – How did it go? Last year, the Western Interconnection, or the part of the North American electric grid that California is part of, reached an all-time record peak demand of 167,988 MWs on July 10, 2024. California's average temperature in July was the hottest of the last 130 years. The peak demand for the year on the CAISO system also occurred in July, at 45,426 MWs. This is earlier in the summer, but lower in demand, than the all-time California system peak of 52,061 MWs in the challenging month of September 2022.[23] Demand in September 2024, by contrast, was lower; never exceeding the July 10, 2024, annual peak.[24] It is also noteworthy that in 2024 the CAISO only called one Flex Alert and one Energy Emergency Alert (EEA) watch, which is at the lowest of the EEA threshold.[25]

Summer 2025 – Expected Demand: As shown in Figure 1, the CEC forecast for the CAISO system in summer 2025 foresees peak demand in September; but the peak forecast for each of the months of July, August, and September is above 45,000 MWs, indicating steadily high demand. The summer 2025 peak is forecast to be approximately 46,152 MWs, in an 6:00-7:00PM (Hour 18) period in September.[26] Nevertheless, the CAISO's assessment of all Resource Adequacy eligible resources under a 1 in 10 Loss of Load Expectation shows a surplus of approximately 1,451 MWs.[27] Additional scenarios under which to assess supply are explored further below in Tables 3 and 4.

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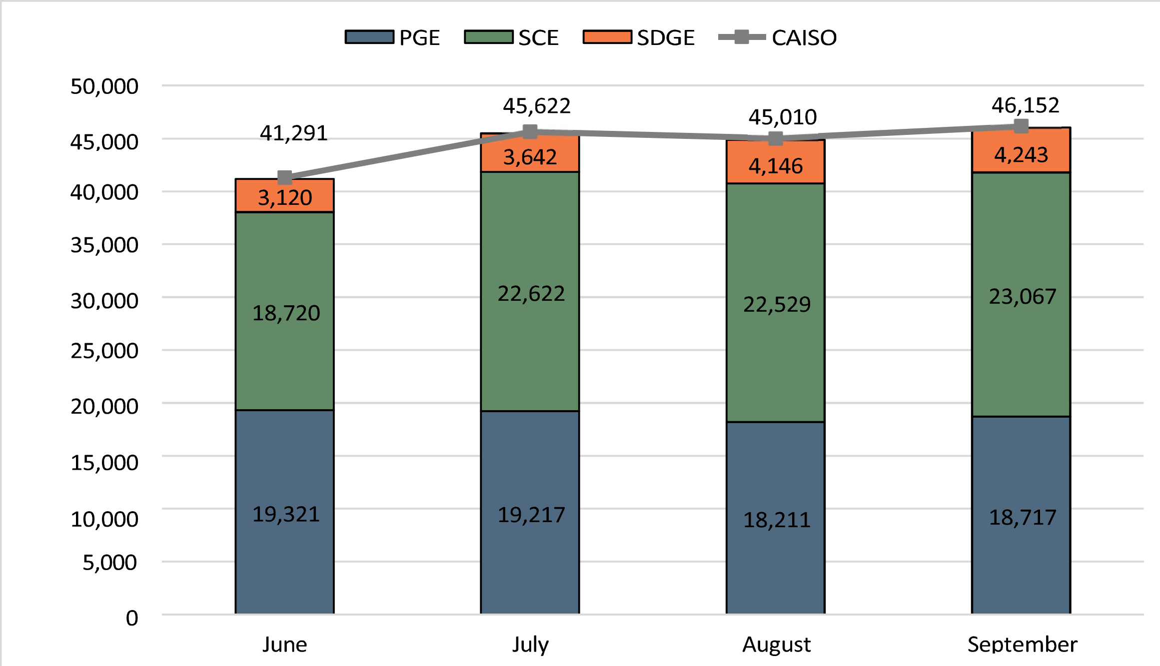
22 CEC, *Staff Report: Assessment of Publicly Owned Utilities Resource Adequacy*, issued April 23, 2024.
23 CAISO, *Summer Market Performance Report: July 2024*, published August 30, 2024.
24 CAISO, *Summer Market Performance Report: September 2024*, published December 5, 2024.
25 A Flex Alert is a public call for voluntary reductions in consumption. It is separate from the Energy Emergency Alert (EEA) system, which starts at EEA Watch for forecasted tight conditions, and then proceeds from EEA 1 to EEA 3 for real-time emergency conditions.
26 This is a 1 in 2 forecasted peak, meaning that there is a 50 percent probability that actual peak load will be less than this estimate, and 50 percent probability that it will be greater.
27 CAISO, *2025 Summer Loads and Resources Assessment,* May 5, 2025, https://www.caiso.com/notices/2025-california-iso-summer-loads-and-resources-assessment-report-posted

Figure 1: CEC Forecast for CAISO System Monthly Peaks in Summer 2025.[28]



Summer 2025 – New Supply to Meet Demand: There have been significant increases in electricity generation and storage capacity on California's electric grid in the last 18 months alone, including nearly 966 MWs in new zero-carbon resources in just the first four months of 2025. Substantially more resources are expected to come online between April 1 and June 30, 2025, as well.[29]

Table 2: New Operational Resources by Nameplate Capacity for Summer 2025.[30]

Technology Type	New in 2024	New in 2025[31]	New 2020-2025, cumulative
Storage	3,678 MWs	802 MWs	10,719 MWs
Solar	2,227 MWs	70 MWs	8,039 MWs
Hybrid (solar + storage)	503 MWs	68 MWs	1,841 MWs
Wind	260 MWs	27 MWs	1,145 MWs
Geothermal	41 MWs	0 MWs	41 MWs
Hydro, Biomass, Biogas	0.5 MWs	0 MWs	39 MWs
Subtotal: new zero-carbon	**6,709 MWs**	**966 MWs**	**21,825 MWs**

[28] CEC, *2024 IEPR Update Planning Forecast*, and CEC/CPUC, *SB 846 Combined First and Second Quarterly Joint Reliability Planning Assessment and SB 1020 Annual Report*, May 1, 2025, in Docket 21-ERS-01.

[29] Up to 1,654 MWs of battery energy storage, 354 MWs of solar, 5 MWs of biofuel, and 150 MWs of hybrid energy resources in the CAISO system, per CAISO, *2025 Summer Loads and Resources Assessment*, May 5, 2025, https://www.caiso.com/notices/2025-california-iso-summer-loads-and-resources-assessment-report-posted

[30] CPUC, "New Energy Resources," CEC Summer Energy Reliability Workshop, May 2, 2025, in Docket 21-ESR-01. Sums may not match totals due to rounding in CPUC figures.
Note: nameplate capacity is a measure of the total rating of an electric facility and is not the equivalent of the metrics used by the state's energy entities to assess the effective capacity of a resource. There are two metrics for the latter, Effective Load Carrying Capacity (ELCC), and Net Qualifying Capacity (NQC). Different resources have different ELCC and NQC values based on how they perform.

[31] Data for 2025 includes projects online as of April 9, 2025.

Technology Type	New in 2024	New in 2025[31]	New 2020-2025, cumulative
Natural Gas (capacity improvements of existing resources)	63 MWs	0 MWs	1,539 MWs
Subtotal: new, in CAISO	**6,772 MWs**	**966 MWs**	**23,364 MWs**
New imports, pseudo-tie, or dynamically scheduled	280 MWs	0 MWs	1,883 MWs
Total new Resources, including imports	**7,054 MWs**	**966 MWs**	**25,247 MWs**

Add it all up and how does it look? The most recent joint energy agencies' summer assessment[32] includes an analysis of all resources relative to supply under different constrained scenarios. Tables 3 and 4 explore this. Reflecting the CEC demand forecast, the benchmark is focused on 6:00-7:00PM in September 2025. The CEC/CPUC assessment shows 59,357 MWs of supply relative to 46,152 MWs of demand. A PRM of 17%, as the CPUC has ordered for its jurisdictional entities, adds with the demand forecast for a total of 53,997.8 MWs of needed capacity. Supply plus demand is then compared by the CEC/CPUC under specified scenarios, including the standard 1 in 10 event, as well as compared to the challenging heat wave events of 2020 and 2022 as recent historic precedent. In each scenario, a surplus is still shown, as below in Tables 3 and 4.

But there are also extraordinary events that CEC/CPUC consider, such as the 2021 Bootleg Fire that caused three lines on the California-Oregon Intertie north of Malin to trip offline. This reduced supply into California by 4,000 MWs in total, and is used by the CEC/CPUC as an informal benchmark for an extraordinary event above the normal planning standards. Adding that, plus a 2020 or 2022 equivalent event, would create a shortfall, as shown below. However, there are also extraordinary resources California has made available for such contingencies as shown in Table 3 below. When factoring in those contingency resources, detailed below, the result is expected surplus during an extraordinary event, even under 2020 or 2022 equivalent conditions.

Table 3: September 2025, Hour 18, Summer Assessment: CEC/CPUC Supply, Demand, and Contingency Resource Estimates.[33]
All amounts in MWs.

Input	Supply	Demand	Supply - Demand
Supply[34]			
Existing Resources	48,032		
Demand Response	1,033		
New Storage	1,722		

[32] Required by Public Resources Code §25233 of the CEC and CPUC (not CAISO). In recent reports, the Air Resources Board has contributed. For simplicity, references to analysis from the joint reliability planning assessments will be referred to as work of CEC/CPUC.
[33] CEC and CPUC, *SB 846 Combined First and Second Quarterly [for 2025] Joint Reliability Planning Assessment and SB 1020 Annual Report*, May 1, 2025, Tables 17, 19.
[34] CEC/CPUC, *Joint Reliability Planning Assessment*, May 1, 2025, in Docket 21-ERS-01, Table 17.

Input	Supply	Demand	Supply - Demand
Solar	1,765		
Wind	1,305		
Resource Adequacy Imports	5,500		
Supply Total	**59,357**		
Demand[35]			
September 2025 Forecast Peak		**46,152**	
17% Planning Reserve Margin (PRM)		7,845.8	
September 2025 Forecast Peak ***+ 17% PRM***		**53,997.8**	
Contingency Resources Available[36]			
DWR: bulk resources in the Electric Supply Strategic Reliability Reserve Program[37]	3,079		
CEC: demand response in the Demand Side Grid Support (DSGS) program[38]		-545	
CEC: dispatchable backup power generation in the Distributed Electricity Backup Assets (DEBA) program[39]	0		
CPUC: ratepayer funded demand response programs[40]		-233	
CPUC: Imports beyond the stack	25		
CPUC: capacity at thermal units above Resource Adequacy rating	474		
Non-program: emergency transfers from balancing authorities	300		
Non-program: thermal resources beyond generation limits	40		
Non-program: thermal resource beyond generation limits, also requiring Federal Power Act Section 202(c) emergency order from the US Department of Energy	25		
Total Contingency Resources	**3,943**	**-778**	**4,721**

35 Ibid.

36 Ibid., at Table 19, uses July, August, and September capacity values. Tables 3 and 4 above displays the September capacity value provided by CEC/CPUC, mirroring the table's showing of the CEC/CPUC assessment of the 2025 forecast peak in September.

37 Includes DWR-owned, dispatchable thermal units and gensets, and DWR-contracted, thermal power plants. For more information, see Table 5.

38 This program is under the umbrella of the Electric Supply Strategic Reliability Reserve Program.

39 The CEC has issued proposed awards for 5 energy storage projects and 4 conventional efficiency projects to date, three of which have been finalized. The CEC reports the total capacity of these projects would be 297 MWs by June 2027. But none will operational this summer. This program is under the umbrella of the Electric Supply Strategic Reliability Reserve Program.

40 Including, for example, the Emergency Load Reduction Program.

Table 4: September 2025, Hour 18, Summer Assessment: CEC/CPUC Assessment of Capacity Under Specified Reliability Scenarios using Supply and Demand CEC/CPUC Figures from Table 3 above.

Input	**Supply**	**Demand**	**Supply - Demand**
Supply - demand under specified scenarios[41]			
1 in 10 planning standard (per CEC/CPUC)			5,512 [42]
17% planning reserve margin			5,359.2
2020 equivalent heat event (per CEC/CPUC)			2,980
2022 equivalent heat event (per CEC/CPUC)			1,368
Supply - demand under specified scenario **AND - *4,000 MWs for supply lost due to a wildfire***[43]			
1 in 10 planning standard (per CEC/CPUC)	-4,000		1,512
17% planning reserve margin	-4,000		1,359.2
2020 equivalent heat event (per CEC/CPUC)	-4,000		-1,020
2022 equivalent heat event (per CEC/CPUC)	-4,000		-2,632
Supply - demand under specified scenarios ***AND - 4,000 MWs for supply lost due to a wildfire*** ***AND + Contingency Resources (if using all)***[44]			
1 in 10 planning standard (per CEC/CPUC)	-4,000 + 3,943	-778	6,233
17% planning reserve margin	-4,000 + 3,943	-778	6,080.2
2020 equivalent heat event (per CEC/CPUC)	-4,000 + 3,943	-778	3,701
2022 equivalent heat event (per CEC/CPUC)	-4,000 + 3,943	-778	2,089

In a further complication of the 2025 reliability outlook, while ordinary supply plus contingency resources appears sufficient to meet demand even with extreme weather or other extraordinary events, how that supply is achieved is noteworthy. For 2025, a series of resources are being stacked to achieve sufficient supply, including a complicated combination of the standard PRM, effective PRM, and additional contingency resources. There is nuance in how the different state energy entities assess this. In a CAISO multi-hour analysis of September 2025, they find a reasonable margin *above the PRM* is required to achieve a 1 in 10 Loss of Load Expectation.

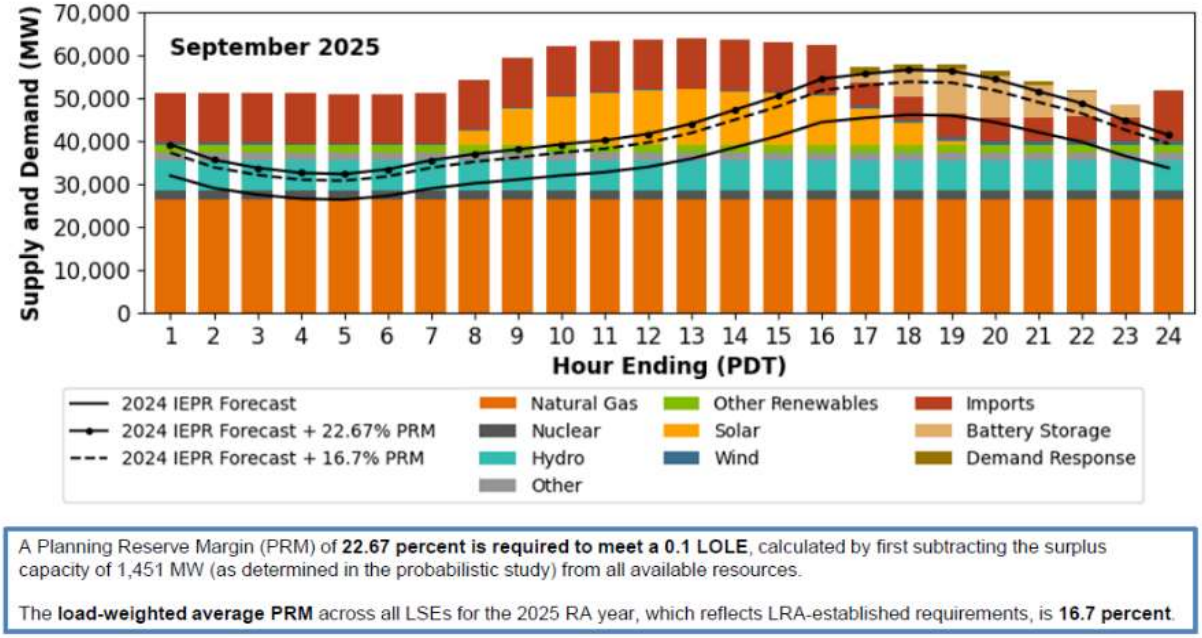
41 CEC/CPUC, *Joint Reliability Planning Assessment*, May 1,2025, in Docket 21-ERS-01.

42 Note: this does not equal the 17% CPUC-adopted planning reserve margin applied directly to the CEC demand forecast; this figure is from the CEC/CPUC *Joint Reliability Planning Assessment*, May 1, 2025, and "1 in 10 planning standard" line included here as it was reported by the CEC/CPUC.

43 CEC/CPUC, *Joint Reliability Planning Assessment*, May 1, 2025, at Table 18, uses the 4,000 overall supply reduction due to the 2021 Bootleg Fire as precedent, as discussed above.

44 It is unlikely that all contingency resources could or would be called upon absent a severe shortfall; nevertheless, it is useful to analyze all contingency resources measured against the CEC/CPUC specified scenarios, along with an extraordinary wildfire scenario, to assess the state's preparedness for such scenarios.

Figure 2: CAISO multi-hour September 2025 stack analysis.[45]



This CAISO analysis finds that, while the PRM for all LSEs is showing up at approximately the CPUC-determined 17%,[46] as expected, the PRM necessary to achieve a 1 in 10 Loss of Load Expectation would actually be substantially higher. But the CAISO also finds a probabilistic analysis of all Resource Adequacy eligible resources, including potential emergency measures, shows a surplus to meet a 1 in 10 Loss of Load Expectation; and thus, “there is sufficient resources to meet a wide range of system conditions.”[47] In other words, CAISO, CEC, and CPUC draw similar conclusions about summer readiness but using marginally different methods. This suggests a deeper divergence, including in how resources are assessed and accounted for reliability purposes, between the state energy entities despite a clear, shared intent to increase cooperation.[48]

Based on Tables 2 through 4 above, the following conclusions can be drawn about the summer 2025 outlook:

- The state has substantively increased levels of new zero-carbon generation in the last 18 months.
- Forecasted supply appears sufficient to meet a 1 in 10 loss of load expectation standard, as well as extreme heat events like those that occurred in 2020 and 2022, absent an extraordinary event like the Bootleg Fire that threatens major transmission lines.
- Using contingency resources, supply appears sufficient to meet an extreme heat event like those that occurred in 2020 and 2022, even when combined with an extraordinary event like the Bootleg Fire; however, absent these contingencies, shortfalls are possible.

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45 CAISO, *2025 Summer Loads and Resources Assessment*, CEC Summer Energy Reliability Workshop, May 2, 2025, in Docket 21-ESR-01.

46 Some CAISO participants are not CPUC-jurisdictional load serving entities, and may have a lower planning reserve margin as a result.

47 CAISO, *2025 Summer Loads and Resources Assessment*, May 5, 2025, link above.

48 CAISO, CEC, and CPUC Memorandum of Understanding, December 2022, https://www.caiso.com/documents/iso-cec-and-cpuc-memorandum-of-understanding-dec-2022.pdf

Part 3 – Mid-Term and Long-Term Electric Reliability Outlook. While electric reliability challenges are not new for California, the events of the past five years illustrate that the pace and the complexity of those challenges puts the state in a novel position, cutting a path where few have yet gone both to our decarbonization goals and through the turbulence created by climate change. The following highlights a number of the novel challenges for policymakers to consider.

Pace of new clean energy resource development – good news: Much time and attention has been paid by this committee and others to oversee the suboptimal pace of new clean resource deployment. The state energy entities have undertaken several actions in recognition of this challenge. This includes the CPUC adopting in February a revised General Order 131-E, reforming the process for permitting transmission projects in their jurisdiction, thereby implementing legislation from 2022.[49] This also includes the creation of interdepartmental forums on energy permitting, including the Tracking Energy Development (TED) Task Force led by GO-Biz, which is currently tracking 123 active projects, and the Governor's Energy Strike Team; although the Legislature has limited insight into what progress made in those forums.[50] Additionally, the CAISO is actively implementing reforms to the interconnection queue process for new resources. The CAISO reports that, in a matter of months, approximately two-thirds of the projects previously in queue have already been cleared.[51] However, challenges remain, including in the timely interconnection of new resources to the electric grid by the incumbent utility.

Pace of new clean energy resource development – bad news: Recently-announced federal tariffs on many countries that contribute to the energy infrastructure supply chain have injected fresh uncertainty into the development process. During the COVID-19 pandemic, California experienced firsthand the cost of supply chain-induced delays on new energy project development.[52] Further trade shocks are likely to impose similar costs and project delays. In the face of growing demand for electricity, as well as the requirement in existing law for LSEs to contribute their part to a diverse and balanced portfolio of resources,[53] it is possible tariff-induced project delays will undermine electric reliability.[54] [55]

According to a national analysis by Bloomberg NEF that includes, but is not limited to, California, energy storage will be the category of resources most affected by tariffs. As shown above in Table 2, energy storage is also the fasting growing category of resources currently. But due to tariffs, the cost of energy storage systems is forecast to spike in 2025, and the pace of new installations is forecast to drop significantly below prior forecasts, particularly in 2026.[56] Storage

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[49] SB 529 (Hertzberg, Statutes of 2022); implemented by General Order 131-E, Adopted in D.25-01-055, issued February 7, 2025, in Rulemaking 23-05-018.

[50] Governor's Office of Business & Economic Development, *Renewable Resource Deployment – Emerging Trends*, CEC Summer Energy Reliability Workshop, May 2, 2025, in Docket 21-ESR-01.

[51] Per FERC, *Order on Tariff Revisions*, issued September 30, 2024, Docket ER24-2671-000.

[52] De Lombaerde, Geert, "COVID Lockdowns May Delay $1.2B SCE Storage Project," *T&D World*, April 12, 2022; https://www.tdworld.com/utility-business/article/21238724/covid-lockdowns-may-delay-12b-sce-storage-project?utm_source=chatgpt.com

[53] Public Utilities Code §454.54.

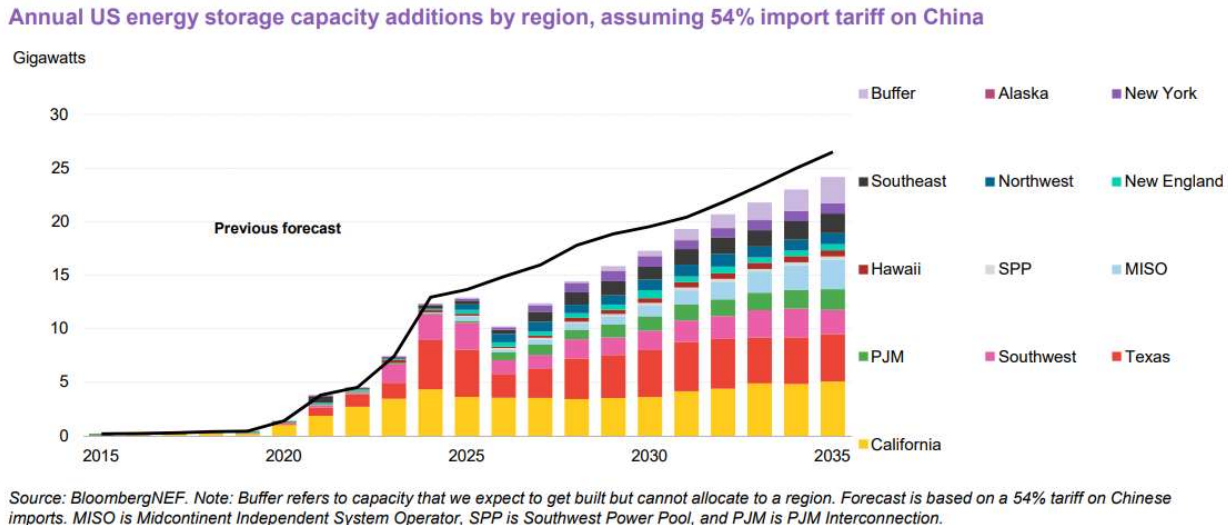
[54] Chu, Amanda, and Smyth, Jamie, "Donald Trump's cuts to renewables risk US energy crisis, warns executives," Financial Times, February 3, 2025, https://www.ft.com/content/47dbfee3-5517-43c6-85ab-dfe86d2d4085

[55] Paulson, Hank, "Hank Paulson: Clean Energy will be critical to winning the AI race with China," Financial Times, April 26, 2025, https://www.ft.com/content/13746dac-7df8-4b4f-9f25-0822e9abdcbc

[56] Flakoll, Derrick, *US and California Energy Overview: From Trends to Tariffs,* CEC Summer Energy Reliability Workshop, May 2, 2025, in Docket 21-ESR-01.

plays a critical role in not only balancing our grid, but meeting our upcoming clean energy targets. The decline in development due to the tariffs is likely to be significant.

Figure 3: Forecasted reduction in new energy storage due to tariffs.[57]



Considerations for policymakers: How are lessons from the COVID-19 pandemic supply chain shocks being used to adapt the near- and mid-term forecast of new energy resource development in California? How much can the state energy entities quantify the potential for delays and cost escalations? What are the reliability implications?

Future of the Electric Supply Strategic Reliability Reserve Program (ESSRRP). In the 2021 May revision to his January budget proposal, Governor Newsom proposed the creation of a combination of programs to be administered by DWR and the CEC: a Strategic Reliability Reserve, the Distributed Electricity Backup Assets program, and the Demand Side Grid Support program; as well as $5.495 billion in multiyear General Fund appropriations for these programs.[58] At that time, the Administration estimated there was risk of a shortfall of up to a 10,000 MWs in 2025, based on a forecast in which three challenges at the time remained unresolved and coincided: (1) a continued lag in demand forecasts and procurement policy behind the pace of the changing climate, (2) extreme weather and fire risks above a the risk anticipated under a 1 in 10 Loss of Load Expectation standard, and (3) continued project development delays.[59] Fortunately, the reliability has significantly improved since then, and there is no such shortfall of 10,000 MWs forecast for 2025.

Later in 2022, the Legislature modified and enacted a version of the Governor's proposal and appropriated $2.95 billion in 2021-2022 and 2022-2023 funding for these programs, under an umbrella later renamed ESSRRP; among other actions.

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[57] Ibid.

[58] Assembly Budget Subcommittee #3 on Climate Crisis, Resources, Energy, & Transportation, *Informational Hearing: May Revision Energy Proposals*, June 1, 2022, https://abgt.assembly.ca.gov/sites/abgt.assembly.ca.gov/files/June%201-%20Sub%203%20Energy%20May%20Revision%20Informational%20Hearing.pdf

[59] State energy entities, *Reliability Challenges Overview*, June 1, 2022, https://abgt.assembly.ca.gov/sites/abgt.assembly.ca.gov/files/Reliability%20Overview%20for%2006.01.22%20Budget%20Sub3%20Hearing.pdf

Table 5: As of the last period for which reporting is available, ESSRRP includes the following resources currently available at the direction of DWR:[60]

Resource	**Type**	**Capacity**
Roseville Energy Park	Natural gas (thermal) turbine units	60 MWs
Calpine Greenleaf 1	Natural gas (thermal) turbine units	60 MWs
Generators in City of Lodi	Natural gas gensets	48 MWs
Generators at Modesto Irrigation District	Natural gas gensets	48 MWs
Generators at Turlock Irrigation District	Natural gas gensets	47 MWs
CSU Channel Islands	Combined cycle natural gas power plant	27.5 MWs
AES Alamitos	Once-through cooled natural gas power plant	1,141.2 MWs
AES Huntington Beach	Once-through cooled natural gas power plant	226.8 MWs
GenON	Once-through cooled natural gas power plant	1,491.3 MWs
		Total: 3,149.8 MWs[61]

These wholesale, DWR-administered ESSRRP resources are expected to continue to be operational and funded through summer 2026. Additional demand-side resources administered by CEC — the demand response resources funded by the Demand Side Grid Support program and the backup power facilities supported by the Distributed Electricity Backup Assets program — were detailed above in Table 3.

Considerations for policymakers: Any reliability-related policy is inherently linked with affordability. To oversimplify, increased reliability increases costs. The traditional balancing act is finding the least-cost, best-fit way to maintain sufficient reliability. One strategy that California has now employed to this end is using General Fund resources to pay for a segment of reliability resources; particularly resources intended to meet demand during extraordinary events. For resources that have the broader societal value of ensuring reliability during extraordinary events, events that may be beyond the ability of current regulations to prepare for, it is logical to fund them from a source (General Fund) that is less regressive than the alternative (ratepayers). But as funding is largely encumbered, if not spent, it is timely to reassess this strategy moving forward. Is more funding needed; if so, when? When will the capacity payments mechanism created in 2023, in which the CPUC can recover costs from ESSRRP resources if a specific load serving entity relies on them, be utilized? How much revenue will that generate, if any? Alternatively, is it better to address this problem by (1) revisiting current reliability policy requirements for power providers; and, (2) revisiting existing

[60] DWR, *Electricity Supply Reliability Reserve Fund Progress Report*, August 1, 2024. This does not include resources previously available/utilized within the ESSRRP in prior years but that are not expected to be used in 2025 or thereafter, such as firm imports funded by the ESSRRP or emergency diesel generators.

[61] Note: this figure, the sum of capacity numbers from DWR, does not match Contingency Resource figures from CEC/CPUC, listed on Table 3; there is a difference of 70.8 MWs.

backstop procurement mechanisms that the state energy entities have used, and can continue to use, to procure and retain capacity for reliability?

Resource Adequacy Reform – Transition to the Slice of Day Framework: In 2021, the CPUC determined that a 'slice of day' approach to Resource Adequacy was an appropriate reform to better reflect the evolution of supply and demand trends, and began a process to begin implementing that framework in 2023 for compliance beginning in 2024.[62] In 2023, the CPUC adopted reforms to operationalize a transition to this framework.[63] Ultimately, 2024 would be a test year and not the first compliance year for slice of day; and 2025 is the first year in which LSEs must comply with these new requirements.

In the slice of day framework, the level to which LSEs must procure to is the peak day of each month, including measurements for each hour within that peak day. This represents the hardest-to-serve slices of the hardest-to-serve day in each month. This is calculated based on the CEC load forecast, which its itself made up of a significant amount of data, subject to adjustment. The obligation for LSEs is to show the CPUC that they have procured enough capacity to meet that expected demand, including the PRM. What LSEs use to meet that requirement is at their discretion, although the CPUC sets the metrics for how to value different resource type.

The slice of day framework is inherently more granular than the system it replaced. The potential value in this complexity is a more detailed approach that reflects the complexity of ensuring electric reliability today, not as it was when Resource Adequacy was created in response to the energy crisis of 2000-2001. The effectiveness of this framework will be tested this summer.

Considerations for policymakers: Is the slice of day and other Resource Adequacy program reforms adequately adapting to changing grid conditions? Are compliance costs, such as Resource Adequacy market prices, coming down from high levels in recent years? Is the Resource Adequacy program performing optimally, or is the addition of other inputs such as the Electric Supply Strategic Reliability Reserve program an illustration of the limitations of this program's functionality? Should the Resource Adequacy program take a more multi-year focus on reliability? How is slice of day interacting with the manner in which CAISO accounts for Resource Adequacy and reliability under its tariff?

Increasing Role of Integrated Resource Planning (IRP): In 2016, the CPUC began using the IRP process to more broadly assess the portfolio of needs necessary to optimally and cost-effectively integrate renewable energy and achieve the state's zero-carbon goals for the electricity sector. What began originally as primarily a decarbonization modelling exercise evolved over time. IRP today looks beyond individual LSEs' supply and demand plans to see how the actions of each interact with all others on the system. It is a reasonable function for the CPUC to fulfill, as the regulator over LSEs' Resource Adequacy and IRP process obligations should have a clear line of sight into the near- to long-term outlook of individual LSEs as well as the system altogether.

With its mid- and long-term outlook, the IRP process is a sibling to the near-term Resource Adequacy program, and these two programs have grown much closer in recent years. On

[62] D.21-07-014, *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program*, issued July 16, 2021, in Rulemaking 19-11-009.

[63] D.23-04-010, *Decision on Phase 2 of the Resource Adequacy Reform Track*, issued April 7, 2023, in Rulemaking 21-10-002.

multiple occasions, state law has been amended to reflect that both Resource Adequacy and IRP are ultimately looking at the same electrical system with different time scales.[64]

The IRP process now operates on two tracks: planning and procurement. In the planning track, the CPUC assesses the individual integrated resource plans of all LSEs compared to what is needed for the system as a whole, relative to the state's decarbonization and other goals. The planning process also results in the transmission portfolio transmitted by the CPUC to the CAISO for use in its Transmission Planning Process, which results in an annual plan that seeks to optimize transmission infrastructure expansion based on economic, reliability, and policy needs.

In the procurement track, which is a newer development in IRP, the CPUC orders procurement by its jurisdictional LSEs in response to a deficiency between the CPUC analysis for what is needed, the preferred system plan, versus what is showing up in the plans of LSEs. In essence, the need for any such procurement reflects a shortfall in the mid-term outlook. To date, the CPUC has exercised its authority to order procurement through the IRP process three times.

Table 6: Procurement ordered by the CPUC in the IRP process.[65]
All amounts in MWs.

CPUC Orders	Total	2021	2022	2023	2024	2025	2026	2027	2028
2019 Order [66]	**3,300**	1,650	825	825	N/A	N/A	N/A	N/A	N/A
2021 Order [67]	**11,500**	N/A	N/A	2,000	6,000	1,500	N/A	N/A	2,000
2023 Order [68]	**4,000**	N/A	N/A	N/A	N/A	N/A	2,000	2,000	N/A
Total Each Year		1,650	825	2,825	6,000	1,500	2,000	2,000	2,000
Cumulative Total	**18,800**	1,650	2,475	5,300	11,300	12,800	14,800	16,800	18,800

Key: Procurement Achieved | Procurement Shortfall

Compliance data per December 2023 CPUC report, the most recent available; more recent compliance data, when made available by the CPUC, may improve this outlook.

64 SB 155 (Bradford, Statutes of 2019) provided that, through the Resource Adequacy program, the CPUC shall ensure reliability on both a near- and long-term basis, as well as serve the existing RPS long-term contracting requirements. AB 1373 (Garcia, Becker, Ting, Statutes of 2023) added resources needed to achieve the state's long-term decarbonization objectives to the scope of the Resource Adequacy program, including further linking it to the IRP process, among many other provisions.

65 CPUC, *Summary of Compliance with IRP Order D.19-11-016 and Mid Term Reliability (MTR) D.21-06-035 Procurement*, December 2023, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/irp12123compliancereport.pdf

66 D.19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023*, issued November 13, 2019, in R.16-02-007. Applies to 25 load serving entities since 18/43 opted out, per the CPUC.

67 D.21-06-035, *Decision Requirement Procurement to Address Mid-Term Reliability (2023-2026)*, issued June 30, 2021, in R.20-05-003. Applies to all CPUC-jurisdictional load serving entities.

68 D.23-02-040, *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios to CAISO for 2023-2024 Transmission Planning Process*, issued February 2, 2023, in R.20-05-003. Applies to all CPUC-jurisdictional load serving entities.

Because resource procurement is principally the responsibility of LSEs, the scale and cadence of these CPUC procurement orders indicate a noteworthy lag in procurement. Put another way, if LSEs were procuring at the necessary pace, none of these orders would have been necessary. However, difficulties in actually securing new procurement — particularly for long lead-time and other hard-to-develop resources — should not be overlooked. In recognition of those challenges, the Legislature passed and the Governor signed into law a central procurement function in which the CPUC can order DWR to be the buyer of certain resources for the system as a whole.[69] However, the exercise of that process is limited to truly long lead-time resources.

Considerations for policymakers: Are LSEs meeting their existing IRP procurement requirements? If not, why? Is the CPUC better integrating the RA and IRP programs, as prior legislation sought to enable? Are there continued delays to IRP procurement coming online? Does the continued need for procurement through the IRP process reflect a fundamental issue with the pace of LSEs' procurement? Where is the current thinking on the ongoing role of the central procurement entity, since it was authorized in statute in 2023? Is it the vision of the CEC/CPUC that the central procurement entity supplement LSE procurement, or compete with it? How is the CPUC responding to the shortfall in the mid-term reliability order for 2024? Is there further update to provide, or cause for concern with this value? Does the central procurement entity need to step further in to help fill a need?

Reliable & Clean Power Procurement Program (RCPPP) in Integrated Resource Planning: Last week, a CPUC staff paper was released on an updated proposal regarding how mid-term procurement could be ordered in the IRP process, as a successor to the to-date somewhat *ad hoc* procurement order process previously used, as detailed above in Table 5

This Reliable and Clean Power Procurement Program (RCPPP) proposal, although very complex, fundamentally proposes two options, the first of which would provide for the procurement of *new and existing* resources for LSEs, and the second of which would provide only for the procurement of *new* resources.[70] The function of either would be to fill procurement gaps that LSEs are unable or unwilling to fill individually, based on the reliability procurement needs of the system. These proposals will be the subject of extensive stakeholder discussion in the coming months in the CPUC IRP proceeding.

Considerations for policymakers: Will this process lead to smoother cadence of procurement driven by the IRP process? Is the complexity of this mechanism justified?

Diablo Canyon Power Plant. As modified by the Legislature in 2022 in response to a request from Governor Newsom, the Diablo Canyon Power Plant in San Luis Obispo County has a statutory retirement date of October 31, 2029, for the 1,073 megawatt unit 1; and October 31, 2030, for the 1,087 megawatt unit 2.[71] Previously, the retirement date for this facility under its existing federal license for the two units were in 2024 and 2025, respectively. The US Nuclear Regulatory Commission is in the process of reviewing a license renewal application that PG&E filed for Diablo Canyon and currently expects to issue a final decision by August 2025.[72] However, the application filed by PG&E is for a 20 year license, creating a discrepancy between

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[69] Water Code Division 29.5, §80800 et seq., as added by AB 1373 (Garcia, Becker, Ting, Statutes of 2023).
[70] CPUC, *Staff Proposal: Reliable and Clean Power Procurement Program*, issued April 29, 2025, in Rulemaking 20-05-003.
[71] Public Resources Code §25548.1, per SB 846 (Dodd, Statutes of 2022).
[72] United States Nuclear Regulatory Commission, *Diablo Canyon – License Renewal Application*, https://www.nrc.gov/reactors/operating/licensing/renewal/applications/diablo-canyon.html

the effective retirement date of this facility provided in statute and the potential retirement date authorized by an extended federal license.

Considerations for policymakers: Is the state and its power providers adequately prepared for the retirement of the Diablo Canyon Power Plant? What would be sufficient to achieve certainty that the state is prepared this time? How has Diablo's retirement factored into IRP and RA planning to date? Have IRP procurement orders for additional, Diablo Canyon-specific capacity materialized sufficiently? Has the market reacted regarding uncertainty in Diablo's retirement date?

Uncertain but rising demand in the forecast: The pace and scale of demand growth for 2030 and beyond has repeatedly been revised upward each year by the CEC, reflecting the effects of climate change and electrification of vehicles and buildings, among other factors. For demand in 2030, that forecast has increased by more than 5,000 MWs alone since the 2018 demand forecast.[73] Among other factors, this increase in demand imposes challenges for reliability by moving the goalpost for what the state energy entities and power providers must plan to meet. Electrification of buildings in particular will also increase California's winter demand peak, creating additional reliability challenges for a state that has grown accustomed to planning for summer electricity peaks.

Much attention has also been raised about the extent to which growing numbers of data centers, and growing reliance on them, will contribute to increased electricity demand. Using data from five utilities in whose service territories data centers are likely to continue to be sited, including PG&E, Silicon Valley Power, and SCE, the CEC estimates an approximately 3,500 megawatt increasing in demand attributable to data centers by 2040.[74] Questions remain as to the pace and impact of this demand growth, particularly given the relatively steady demand profile of a data center compared to other retail customers.

Considerations for policymakers: What is a reasonable level of uncertainty to expect in demand forecasts, and is the current level satisfactory? How can the state and its power providers better realize opportunities associated with electrification to maximize the multipurpose value of new clean infrastructure, including new distributed energy resources? How can wholesale and distributed resource owners better encourage or induce their resources to operate for the benefit of the system as well as their own bottom line?

Western electricity markets: While interregional cooperation among electricity market participants is not new, a variety of additional activities are taking place across the west.

The West-Wide Grid Governance Pathways Initiative: Begun by a variety of state energy regulators across the west, including California, the Pathways initiative started in 2023 as a consultative process to determine the potential for increased western electricity market cooperation. After an extensive process, a step 1 proposal was finalized and transmitted to the CAISO Board of Governors and Western Energy Imbalance Market Governing Body that described changes to current practices necessary to incrementally move towards increased, voluntary, and cooperative regional governance of electricity markets within the limits of

[73] Figure ES-2, CEC, *Final Adopted 2023 Integrated Energy Policy Report*, February 14, 2024, in 23-IEPR-01.
[74] CEC, *Demand Forecast*, CEC Summer Energy Reliability Workshop, May 2, 2025, in Docket 21-ESR-01.

existing law.[75] In August, the CAISO Board of Governors approved, and FERC later accepted, an amendment to the CAISO's governing tariff, reflecting a broader implementation of the step 1 proposal.[76] Later in 2024, a step 2 proposal was released by the launch committee for this initiative, detailing for public consideration the various steps necessary to realize a larger, voluntary wholesale electricity market for California and other western states to participate in, as a way to increase resource diversity and reliability across the Western Interconnection.[77]

Western Resource Adequacy Program: Initiated by the Western Power Pool, this FERC-approved program[78] intends to provide a voluntary resource adequacy planning and compliance program for participants in the Western Interconnection. In 2024, the initial operation date for this program was delayed one year to 2027.

Considerations for policymakers: What should California's role in the Western Interconnection look like? How should California manage its dependency on imported electricity supply during peak periods and exported electricity supply during shoulder periods? Are other western states developing new resources at the same pace as California to serve demand? Are there any lessons to be learned from the reliability event in Spain that could have implications for this larger discussion?

Central Procurement: In 2024, after completing an assessment of the need for long lead-time resources over and above those shown in LSEs' integrated resource plans, the CPUC determined a need to use the central procurement function authorized in 2023[79] to procure up to 7,600 MWs of offshore wind energy, up to 1,000 MWs of geothermal energy, up to 1,000 MWs of multi-day long-duration energy storage, and up to 1,000 MWs of long-duration energy storage facilities with a longer, 12+ hour discharge period.[80] In February of this year, the CPUC officially requested that DWR initiate its role in this central procurement function and begin the process of soliciting resources. This work is ongoing and is expected to result in a first solicitation in 2026, with other solicitations to follow.

Considerations for policymakers: How should DWR be equipped to best manage the solicitation and potential procurement of these resources? How does federal policy uncertainty impact the development of these long lead-time resources? What is an appropriate cost framework under which to value these resources based on near- and long-term value? Dispatchable generation is a key element to reliability currently — how do these long lead-time resources best equip California to supplement or replace current dispatchable resources that may not be consistent with long-term decarbonization requirements?

Conclusions: While the summer 2025 outlook appears sufficient even under stressed conditions, the mid-term and long-term outlook present a less clear picture with a number of areas including, but not limited to, that touched on above being worthy of policymakers' time and attention.

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[75] West-Wide Governance Pathways Initiative, Letter to CAISO Board of Governors and WEIM Governing Body, June 5, 2024, https://www.westernenergyboard.org/wp-content/uploads/Pathways-Step-1-Final-Proposal.pdf

[76] FERC, Order Accepting Tariff Amendment, April 2, 2025, Docket ER25-542-000.

[77] West-Wide Grid Pathways Initiative Launch Committee, *Step 2 Final Proposal*, November 15, 2024, https://www.westernenergyboard.org/wp-content/uploads/Pathways-Initiative-Step-2-Final-Proposal.pdf

[78] FERC, *Order Accepting Proposed Tariff*, Dockets ER22-2762-000, ER22-2762-001, issued February 10, 2023.

[79] Per Public Utilities Code §454.52, as amended by AB 1373 (Garcia, Becker, Ting, Statutes of 2023).

[80] D.24-08-064, *Decision Determining Need for Centralized Procurement of Long Lead-Time Resources*, issued August 29, 2024, in Rulemaking 20-05-003.