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Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.	Rulemaking 25-06-019

ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ELECTRICITY PORTFOLIOS FOR 2026-2027 TRANSMISSION PLANNING PROCESS AND NEED FOR ADDITIONAL RELIABILITY PROCUREMENT

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ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ELECTRICITY PORTFOLIOS FOR 2026-2027 TRANSMISSION PLANNING PROCESS AND NEED FOR ADDITIONAL RELIABILITY PROCUREMENT

Summary

This ruling invites comments on proposed electricity resource portfolios for use in the California Independent System Operator's (CAISO's) 2026-2027 Transmission Planning Process (TPP). In addition, this ruling presents a staff analysis on the need for additional reliability procurement, beyond the amounts ordered in Decisions (D.) 21-06-035 and D.23-02-040, also known as the mid-term reliability (MTR) and supplemental MTR decisions, respectively. Parties are invited to give feedback on this analysis and any actions the Commission should take as a result.

Comments in response to this ruling are invited to be filed and served no later than October 22, 2025, with reply comments filed and served no later than October 31, 2025.

1. Background

This section provides a short background on the TPP recommendations, as well as the procurement need analysis.

1.1. Transmission Planning Process

As part of the longstanding memorandum of understanding (MOU) between the California Energy Commission (CEC), CAISO, and this Commission to collaborate on electricity resource and transmission planning, every year Commission staff develops a recommended set of portfolios for the CAISO to use in its annual TPP.

Generally, in each TPP cycle, the CAISO evaluates a reliability and/or policy-driven base case portfolio. Under the CAISO tariff adopted by the Federal Energy Regulatory Commission (FERC), if the results of the base case analysis

show the need for additional transmission development, the transmission projects are brought to the CAISO Board for approval in the spring of the second year of the TPP. If approved by the CAISO Board, under the FERC tariff, the project would receive cost recovery through the transmission access charge.

Along with the base case analysis that generally leads directly to transmission project approval, in each TPP cycle the CAISO typically analyzes one or more sensitivity portfolios. The purpose of the sensitivity portfolio analysis is to assist in future planning by identifying relevant transmission needs and potential costs.

Decision (D.) 25-02-026 included both a base case and a sensitivity portfolio that the CAISO is in the process of analyzing for the current 2025-2026 TPP cycle. The base case portfolio was based on the scenario that achieves a 25 million metric ton (MMT) statewide greenhouse gas (GHG) emissions target in 2035, and includes the resources online or planned in the individual load-serving entity (LSE) IRPs submitted in November 2022, including 4.5 gigawatts (GW) of offshore wind that is currently included in the recommended 2026-2027 TPP base case.

The 2025-2026 TPP sensitivity portfolio currently being studied by CAISO is a long lead-time (LLT) resource sensitivity. This sensitivity is based on the upper bounds of the need determination analysis of LLT resources volumes that the Department of Water Resources (DWR), as a Central Procurement Entity, could potentially procure, as reflected in the Commission's adopted decision (D.24-08-064). The need determination in D.24-08-064 included geothermal, long-duration energy storage (LDES) with specified durations, and offshore wind resources.

1.2. Load Serving Entity Procurement Requirements

In D.21-06-035, also known as the MTR decision, the Commission required LSEs to procure 11,500 megawatts (MW) of net qualifying capacity (NQC)[1] between 2023 and 2026. D.23-02-040 (the Supplemental MTR decision) required an additional 4,000 MW of NQC to be procured by 2028, using the same basic framework as D.21-06-035. D.23-02-040 also postponed the requirements for 2,000 MW NQC of LLT resources, as defined in the MTR decision, to be procured by LSEs until 2028, with the potential for further extension to 2031, while allowing LSEs to cover any delays with generic capacity resources to cover the delayed NQC from MTR's LLT resources.

In Rulemaking (R.) 20-05-003, the prior IRP proceeding, a Staff Proposal for the Reliable and Clean Power Procurement Program (RCPPP) is under consideration.[2] One of the objectives of the RCPPP, if adopted, would be to assign an ongoing reliability and clean energy procurement requirement to all LSEs, so that LSEs know in advance what their procurement requirements are, to help avoid the need for the Commission to order periodic additional procurement in the IRP proceeding.

Parties have filed opening comments and reply comments on the content of the RCPPP Staff Proposal in R.20-05-003 and the details of RCPPP will continue to be addressed in that rulemaking. However, some parties, in commenting on the timing of the potential for an RCPPP to be adopted, have commented that the Commission should consider another interim procurement

[1] NQC for each tranche of procurement required from LSEs is based on vintaged marginal effective load carrying capability (ELCC) values.

[2] *See* Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal, April 29, 2025, in R.20-05-003 available at the following link: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=565140721.

order, to maintain electric system reliability during the time period while the RCPPP framework is considered and the implementation details are worked out. In response to the RCPPP Staff Proposal, 20 parties commented on near-term reliability needs, generally for the period 2028-2032. Numerous parties generally recommended that the Commission conduct a near-term reliability need determination and issue an interim procurement order if a system reliability need is found.

Separately, also in R.20-05-003, American Clean Power – California (ACP-CA) filed a Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement. Parties filed responses to the ACP-CA Motion on August 5, 2025 in R.20-05-003. Similar to the RCPPP Staff Proposal, the ACP-CA motion will be addressed in R.20-05-003. However, elements of the ACP-CA motion and its rationale are relevant to the near-term need determination presented in this ruling.

In particular, many parties argue that the sunsetting of federal tax credits, including the investment tax credit (ITC) and the production tax credit (PTC), will have negative cost impacts on ratepayers related to procurement of renewable resources, with levelized cost increases of between 73-90 percent for utility-scale solar and 14-150 percent for onshore wind.

However, some parties also express concerns that a procurement order from the Commission via the IRP proceeding could increase ratepayer costs, due to a frenzy of procurement by a large number of LSEs in an already tight market. Many LSEs argue that they are already procuring as much as possible, and more requirements would not assist in the areas where procurement is delayed because of interconnection and permitting issues or supply chain issues. Some

parties are concerned that a procurement order now could lead to market distortion.

Section 3 of this ruling discusses the analysis conducted by Commission staff to determine system reliability need in 2028-2032, taking into account the RCPPP comments, as well as responses to the ACP-CA motion.

2. Transmission Planning Process Portfolio Recommendations

In general, the electricity resource portfolios transmitted to the CAISO for TPP analysis form the basis for the CAISO's consideration of transmission need in the ten-year and 15-year planning horizon.

Base cases are designed to reflect Commission policy guidance, including meeting the reliability standard and achieving GHG reduction targets. Base cases lead to identified transmission solutions that can go directly to the CAISO Board of Governors for approval for investment.

Policy-driven sensitivities are designed to either 1) support a "least regrets" approach that provides a reasonable range of future scenarios that can be linked to the base case or 2) gather additional information to potentially support future portfolio development and explore incremental optionality or risk. Identified transmission solutions in policy-driven sensitivities do not go directly to the CAISO Board for approval, but often help inform future base case portfolios.

The development and recommendations of portfolio for TPP are informed by the Framework for Portfolio Selection, a document developed by Commission staff initially in 2020. It has been updated this year and published on the Commission's website at the following link:

https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-

planning/2024-26-irp-cycle-events-and-materials/assumptions-for-the-2026-2027-tpp

2.1. Modeling Assumption Updates

Prior to recommending a base case portfolio, as well as any sensitivity portfolios, every year Commission staff update numerous assumptions on which the analysis of the portfolios is based. Since releasing the Draft 2025 Inputs and Assumptions document,[3] there have been several high-level policy changes, in addition to various changes to resource-specific assumptions.

First, the modeling takes into account the impacts of recent Federal action, including:

- The FY 2025 Congressional Reconciliation Bill (also referred to as the One Big Beautiful Bill Act (OBBBA) that has impacted tax credit assumptions for impacted technologies, including wind, solar, and other resources; and
- The introduction of wide-ranging tariffs, applying across numerous trading partners, impacting every technology, with special impact on technologies dependent on imports from China and Southeast Asia.

Not included in the changed assumptions used for the analysis presented in this ruling, but on the horizon and being monitored are impacts related to:

- Anti-Dumping and Countervailing Duties (AD/CVD); and
- Foreign Entities of Concern (FEOC).

Guidance from the Treasury Department and Department of Energy, respectively, were not published in time to ensure sufficient review and

[3] The Draft 2025 Inputs and Assumptions document is available at the following link: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_draft_inputs_and_assumptions_doc_20250220.pdf

incorporation of these issues into the updated modeling inputs developed in advance of this ruling.

For the updates to the tax credit assumptions, the model assumptions include ending tax credits for wind and solar projects that fail to commence construction by July 4, 2026. Energy storage and clean-firm technologies retain tax credit eligibility through 2032, as well as safe-harboring provisions and the three-year phase-out previously established in the Inflation Reduction Act of 2022.

For the tariff assumption changes, current tariff policy is assumed to last through 2029, reflecting historical precedent and consistent with how IRP modeling has treated similar assumptions in previous modeling efforts. U.S. trade policy impacts by technology were estimated by assessing the supply chains of imported components by country and applying the latest tariff rates (as of July 2025) to the proportions of projects' capital expenditures attributed to those imports, with the awareness that many of the assumptions are likely fluid. The analysis concludes that tariff impacts are largest for solar and lithium-ion battery storage, which source most of their components from China and Southeast Asia. The analysis also assumes that solar developers will be able to adapt their supply chains to avoid AD/CVD penalties. The staff analysis also notes that the battery energy storage supply chain is uniquely dependent on imports from China, which is subject to some of the highest tariffs overall under current policy.

The resulting weighted average tariff for onshore wind is 29 percent, utility-scale solar photovoltaics is 70 percent, and battery storage (lithium-ion) is 122 percent. As noted earlier, this impact on battery storage costs does not consider the fact that China has been flagged as a FEOC. Under preliminary

guidance, battery storage developers will need to demonstrate that the majority of their capital expenditures are not sourced from Chinese suppliers, or else risk forfeiture of federal tax credits. These impacts are not yet captured in the analysis presented herein.

In addition, wind resources are also affected by recent federal policies delaying or cancelling projects sited on federal land or seeking federal permits. The near-term onshore wind pressures are factored into the base case onshore wind development, but some consideration of impacts on extended offshore wind development timelines are also included in the recommendations for the base case portfolio. The recommended 2026-2027 TPP sensitivity portfolio considers the impact that federal policy could have on both onshore and offshore wind development. Regardless of federal policy changes, it is important to note that offshore wind is not optimally selected in least-cost modeling and its inclusion in recent TPP portfolios relies on previously-planned LSE resources included in their individual IRPs filed in 2022. In addition, the supply chain for wind turbines appears to be relatively insulated from many of the recent federal policy measures.

Other updates to the RESOLVE inputs for the 2026-2027 TPP include:

- Updates to the solar, wind, and near-field enhanced geothermal systems (EGS) resource potential;
- New transmission cost adders for out-of-CAISO wind and geothermal resources in Northeast California and the Imperial Valley;
- Full representation of Deep EGS on CAISO transmission deliverability constraints; changes to the retention costs of existing thermal units; and
- Corrections to the offshore wind hourly generation profiles.

2.2. Recommended 2026-2027 Base Case Portfolio

This ruling presents a recommended option for the 2026-2027 TPP Base Case portfolio and provides a Least-Cost Comparison portfolio as a point of reference. The recommended 2026-2027 Base Case portfolio includes a portion (approximately half) of the upper bound of long lead-time resources (LLT) considered for central procurement by DWR in the need determination adopted in D.24-08-064, per Assembly Bill (AB) 1373 (Stats. 2023, CH. 367).

Table 1 below presents the core assumption elements for the recommended TPP Base Case and the Least-Cost Comparison portfolio, with more detailed information available in the supplemental materials available at the following link:

https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2024-26-irp-cycle-events-and-materials/assumptions-for-the-2026-2027-tpp.

As noted in the table, the main differences between the recommended 2026-2027 TPP Base Case portfolio and the Least-Cost Comparison portfolio are in the amount of LLT resources assumed to be procured in response to the upper bound of the Commission's need determination analysis, pursuant to AB 1373, and the assumption about when those resources will become available.

In contrast to the recommended 2026-2027 TPP Base Case portfolio, the Least-Cost Comparison portfolio allows the RESOLVE capacity expansion model to optimally select the least-cost resources available to it beyond those already procured by the LSEs. The recommended Base Case portfolio forces in approximately half of the volumes of the resource types included in D.24-08-064, which authorized procurement of specified LLT resources by the DWR on behalf

of all consumers served by LSEs under the Commission's IRP purview. In addition, the recommended 2026-2027 Base Case would retain the amount of offshore wind that LSEs reported in their November 2022 individual IRPs and as was included in the previous TPP portfolio (4.5 GW total), but it assumes that the 2.9 GW in Morro Bay would come online by 2036 rather than 2032, and the 1.6 GW in Humboldt would come online by 2041 rather than 2035.

Table 1. Comparison Matrix of Assumptions for Recommended and Comparison Base Case Scenarios

Factor	**Least-Cost Comparison Case**	**Recommended 2026-2027 TPP Base Case Portfolio**
Procurement Forced Into Portfolio	None	Half of the LLT volumes of each resource type included in D.24-08-024
Onshore Wind Availability	Base Potential	Base Potential
Offshore Wind Availability	Base Potential	Extends online dates
DCPP Availability	Retires in 2025, according to Senate Bill (SB) 846 (Stats. 2022, Ch. 239) requirements	Retires in 2025, according to SB 846 requirements
New Natural Gas Capacity Availability	None	None
GHG Target	25 MMT by 2035 and 8 MMT by 2045	25 MMT by 2035 and 8 MMT by 2045
Load Forecast	2024 Integrated Energy Policy Report (IEPR) Forecast	2024 IEPR Forecast

Table 2 below presents the selected resources in the Least-Cost Comparison Portfolio. Of note, geothermal resources are selected for reliability needs due to their high effective load carrying capability (ELCC) values, in addition to their high-capacity-factor, GHG-free energy output. In this scenario,

most of the conventional geothermal potential is built out by 2036, and additional EGS are built in that year, which is prior to the expiration of tax credits for those resources. This is consistent with previous IRP modeling showing the need for firm, dispatchable resources. In addition, almost all available out-of-state wind is selected. In-state onshore wind building, accelerated in the near term by the expiring federal tax credits and GHG target, is constrained by near-term feasibility limits through 2032, with additional build slowing through the 2030s until around 2041. In this scenario, a large buildout of solar and storage resources is required to meet growing energy demand in all years. The buildout of solar, in particular, is so large that it calls into question whether it can feasibly be built in the quantities and timing identified in this round of IRP modeling.

Commission staff note that the recent build rates for solar resources have been between 1-3 GW per year. The amount of solar resources selected in the recommended Base Case portfolio, as well as the Least-Cost Comparison portfolio, will require build rates between 4-7 GW per year going forward. In either case, RESOLVE is selecting nearly all of the solar with completed cluster studies in the CAISO interconnection queue.

Table 2. RESOLVE Selected Resources in Least-Cost Comparison Portfolio (GW)

Resource Type	**2026**	**2028**	**2031**	**2036**	**2041**	**2045**
Natural Gas	-	-	-	-	-	-
Geothermal	0.1	0.4	1.2	3.4	3.4	4.0
Geothermal (enhanced)	-	-	-	1.8	1.8	1.8
Biomass	-	-	-	-	-	-
In-State Wind	0.3	0.8	2.3	2.8	5.7	8.3
Out-of-State Wind	1.4	2.9	5.5	8.8	19.0	19.0
Offshore Wind	-	-	-	-	-	-
Solar	4.0	15.0	35.2	47.3	56.2	71.5
Li-ion Battery (4 hr)	3.9	6.7	6.8	6.8	6.8	6.8

Resource Type	2026	2028	2031	2036	2041	2045
Li-ion Battery (8 hr)	0.2	1.0	10.4	14.4	14.4	21.1
Location-Constrained Storage (12 hr)	-	-	1.6	5.4	5.4	5.4
Generic LDES (12 hr)	-	-	-	-	-	-
Generic LDES (24 hr)	-	-	-	-	-	-
Generic LDES (100 hr)	-	-	-	-	-	-
Shed Demand Response	-	-	-	-	-	-
Gas Capacity Not Retained	(1.3)	(1.8)	(1.8)	(1.8)	(1.8)	(1.8)

In addition, the Least-Cost Comparison portfolio selects an expansion of transmission capacity between the Pacific Gas and Electric Company (PG&E) service territory and that of Southern California Edison (SCE). Path 26 and Path 15 expansions are selected primarily to increase import capacity into PG&E's territory because of the projected load growth there. The first tranche of expansions (1 GW) is selected in the first available year, which is 2036. Significant expansion (about 3 GW in total) is shown to be needed by 2041, with nearly the entire 5.5 GW potential needed by 2045. The costs of this transmission expansion are taken into consideration by the RESOLVE model. The expansion mitigates South-to-North congestion, decreases renewable curtailment, and offsets additional investment costs to meet the GHG target.

Turning to the recommended 2026-2027 TPP Base Case portfolio, with updated assumptions on offshore wind online dates, the selected resources appear similar to the Least-Cost Comparison portfolio, except that the specified offshore wind development offsets some of the large solar buildout in later years. The amounts of offshore wind and multi-day storage, based on LSEs' November 2022 IRPs and on the AB 1373 need determination analysis, respectively, are specified in the model as minimum build limits. RESOLVE does not select any incremental amounts of these resources due to the high cost. Table 3 below

shows the buildout selected by RESOLVE for the recommended 2026-2027 TPP Base Case portfolio.

Table 3. Selected Resources in Recommended 2026-2027 TPP Base Case Portfolio (GW)

Resource Type	**2026**	**2028**	**2031**	**2036**	**2041**	**2045**
Natural Gas	-	-	-	-	-	-
Geothermal	0.1	0.3	1.2	3.4	3.4	3.4
Geothermal (enhanced)	-	-	-	1.7	1.7	1.7
Biomass	-	-	-	-	-	-
In-State Wind	0.3	0.8	2.0	2.6	4.8	7.7
Out-of-State Wind	1.4	2.9	5.5	7.0	17.0	19.0
Offshore Wind	-	-	-	2.9	4.5	4.5
Solar	4.0	15.0	35.9	47.5	53.7	68.5
Li-ion Battery (4 hr)	3.9	6.7	6.8	6.8	6.8	6.8
Li-ion Battery (8 hr)	0.2	1.0	10.0	13.2	13.2	18.6
Location-Constrained Storage (12 hr)	-	-	1.6	5.4	5.4	5.4
Generic LDES (12 hr)	-	-	-	-	-	-
Generic LDES (24 hr)	-	-	-	0.5	0.5	0.5
Generic LDES (100 hr)	-	-	-	-	-	-
Shed Demand Response	-	-	-	-	-	-
Gas Capacity Not Retained	(1.3)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)

Comparing the Least-Cost Comparison portfolio and the recommended Base Case portfolio, both show a general increase in selected capacity due to the increased load in the 2024 IEPR load forecast, which has a gross peak that is approximately 4.4 GW higher than the previous forecast during the middle of the 2030 decade. In both instances, most of the incremental capacity selected to serve this increased load is solar, storage, and geothermal. A great deal of out-of-state wind, as well as in-state wind at levels not recently developed, is also needed.

In terms of cost, the cost differences between the two portfolios are minimal through 2031, but then increase, driven by the higher assumed costs of the offshore wind and multi-day storage. Table 4 below shows the cost

comparison between the two portfolios. The costs shown are only the costs that are optimized within the RESOLVE model.

Table 4. System Cost Comparison in RESOLVE-Optimized Costs Between Least Cost Comparison and Recommended 2026-2027 TPP Base Case Portfolios (Millions of 2024 Dollars)

Year	**Least-Cost Comparison Portfolio**	**Recommended 2026-2027 TPP Base Case Portfolio**	**Difference**	**Difference (%)**
2026	8,758	8,758	(0)	(0.0)
2028	11,983	11,995	12	0.1
2031	18,094	18,066	28	0.2
2036	24,231	26,174	1,943	8.0
2041	28,392	30,730	2,338	8.2
2045	34,865	37,317	2,452	7.0
Net Present Value	*394,735*	*417,749*	*23,014*	*5.8*

Commission staff's recommended 2026-2027 TPP Base Case is a reliability and policy-driven base case scenario that maintains offshore wind volumes, as previously planned for by LSEs as of their November 2022 IRPs. At the same time, the assumptions show uncertainty with respect to the timing of the development of the resources, if it becomes apparent that bids that DWR receives are too expensive and/or do not contain sufficient ratepayer risk protections. A delay in the resource development would also delay the timing of the development of transmission needed for these offshore wind resources.

The recommended 2026-2027 TPP Base Case portfolio will provide the CAISO information it needs to study the transmission needed for the other non-offshore-wind resources that are needed in the nearer term in California. Finally, the recommended Base Case portfolio also represents a middle ground with

respect to the need determination made in D.24-08-064, which sets maximum procurement amounts that may not be fully contracted and developed.

The full details of the staff analysis of the recommended 2026-2027 TPP Base Case portfolio and the Least-Cost Comparison portfolio will be posted at the following link on the Commission web site:

https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2024-26-irp-cycle-events-and-materials/assumptions-for-the-2026-2027-tpp

2.3. Recommended 2026-2027 Sensitivity Portfolio

For the sensitivity portfolio, this ruling recommends one option to be studied, as described below. Another alternative would be not to study a sensitivity portfolio in the 2026-2027 TPP. In addition, Commission staff also evaluated, but are not recommending, two other potential sensitivity portfolios. Parties should keep in mind that the purpose of the sensitivity portfolios is often to test the differential transmission needs of the sensitivity. In no way should any of the sensitivity portfolios evaluated or recommended be interpreted as a policy recommendation or a preferred outcome.

The one sensitivity portfolio recommended herein is a Limited Wind Sensitivity portfolio. The purpose of the portfolio is to reflect the recent lack of wind development in California, the recent increased difficulty of permitting wind in California, and the recent changes in Federal policy toward wind projects. As stated above, this Limited Wind Sensitivity is not intended as a policy preference of any kind from the Commission or staff. It is intended to study how transmission needs would differ if recent preferred system plan portfolios and prior TPP portfolios change over time to include fewer wind resources.

The Limited Wind Sensitivity would provide CAISO a portfolio enabling their TPP process to explore significant reductions to wind resource potential in order to study transmission alternatives. The in-state wind potential would be limited to 2.5 GW, with out-of-state wind potential limited to the amount available to be delivered on existing transmission where the CAISO has rights (which includes the SunZia line, the SWIP-North line, and TransWest transmission), with the addition of 2 GW of extra potential on the SunZia line. The sensitivity portfolio also would not include offshore wind, as it is not optimally selected.

Figure 1 below shows the wind potential that would be included in the Limited Wind Sensitivity compared to the Base Case portfolio recommended above.

Figure 1. Onshore Wind Resource Potential Included in Recommended Portfolios

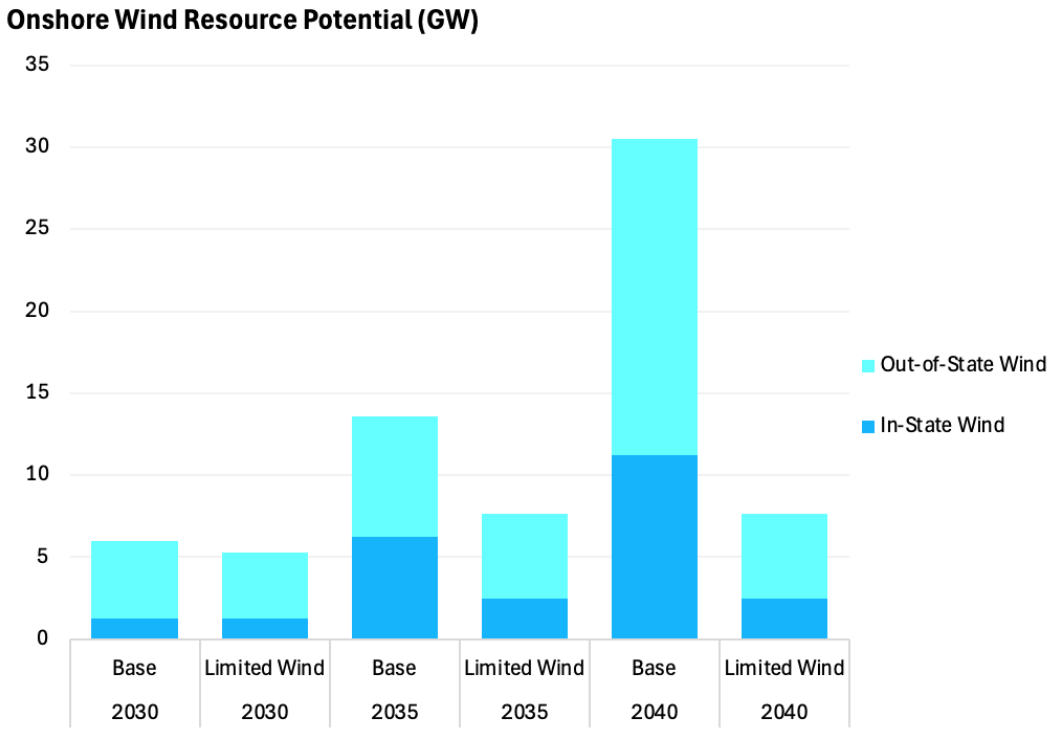

Table 5 below shows the volume of other resources selected by RESOLVE once the volume of wind resources is constrained as described above. The model selects the entire conventional geothermal potential, as well as a significant amount of EGS. Solar and storage resources are also optimally selected at very high levels to meet the growing GHG-free energy demand. A smaller amount of gas is also retired compared to the Base Case.

Table 5. Selected Resources in Limited Wind Sensitivity (GW)

Resource Type	**2026**	**2028**	**2031**	**2036**	**2041**	**2045**
Natural Gas	-	-	-	-	-	-
Geothermal	0.1	0.6	1.2	3.4	4.7	5.6
Geothermal (enhanced)	-	-	-	3.6	3.6	3.6
Biomass	-	-	-	-	-	-
In-State Wind	0.3	0.8	0.9	0.9	2.5	2.5
Out-of-State Wind	1.4	2.5	4.0	4.0	5.1	5.1
Offshore Wind	-	-	-	-	-	-
Solar	4.0	15.0	37.5	48.6	67.6	83.2
Li-ion Battery (4 hr)	3.9	6.7	6.8	6.8	6.8	6.8
Li-ion Battery (8 hr)	0.2	1.0	12.1	17.7	17.7	26.9
Location-Constrained Storage (12 hr)	-	-	1.6	5.7	7.5	7.5
Generic LDES (12 hr)	-	-	-	-	-	-
Generic LDES (24 hr)	-	-	-	-	-	-
Generic LDES (100 hr)	-	-	-	-	-	-
Shed Demand Response	-	-	-	-	-	-
Gas Capacity Not Retained	(1.2)	(1.2)	(1.2)	(1.2)	(1.2)	(1.2)

Notably, limiting the wind potential in this significant way has modest cost impacts in the near term, but by the 2040s increases overall portfolio costs significantly, based on current resource cost forecasts. Table 6 below summarizes the cost estimates of the Limited Wind Sensitivity portfolio compared with the Least-Cost Comparison portfolio. The costs shown are only the costs that are optimized within the RESOLVE model.

Table 6. System Cost Comparison in RESOLVE-Optimized Costs Between Limited Wind Sensitivity and Lead-Cost Portfolio (Millions of 2024 Dollars)

Year	**Least-Cost Comparison portfolio**	**Limited Wind Sensitivity**	**Difference**	**Difference (%)**
2026	8,758	8,759	1	<0.1
2028	11,983	12,001	18	0.1
2031	18,094	18,104	10	0.1
2036	24,231	24,816	585	2.4
2041	28,392	29,720	1,328	4.7
2045	34,865	36,071	1,206	3.5
Net Present Value	*394,735*	*405,466*	*10,731*	*2.7*

The full details of the staff analysis of the Limited Wind Sensitivity portfolio will be posted at the following link on the Commission web site:

https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2024-26-irp-cycle-events-and-materials/assumptions-for-the-2026-2027-tpp

Also included in the slide deck materials posted on the Commission's web site are two other sensitivity portfolios that were evaluated, but ultimately not recommended. The first is a Diablo Canyon Power Plant (DCPP) Extension Sensitivity, which models DCPP as receiving a 20-year extension from retiring in 2024/2025 to being extended through 2045 for Units 1 and 2. The results of this sensitivity would reduce the need primarily for solar and storage, with small decreases in wind and geothermal builds. This sensitivity does not tell us a great deal about future transmission needs, however, because DCPP is already online.

In addition, the Commission is statutorily required to plan as if DCPP is offline beginning in 2024/2025.[4]

The second sensitivity considered but not recommended in this ruling is a GHG Reductions to 25 MMT Sensitivity. This scenario would maintain the adopted 25 MMT GHG target in 2035, but then hold the GHG target constant thereafter from 2035 through 2045. In this scenario, the GHG target continues to bind through 2045. The resulting clean energy standard (CES) values exceed Senate Bill 100 (Stats. 2018, Ch. 312) requirements slightly. New natural gas generation is made available to be selected by RESOLVE for reliability purposes. As with the DCPP extension scenario, the GHG Reductions to 25 MMT Sensitivity does not reveal a great deal about transmission need. This sensitivity does, however, highlight the emissions reductions that the state is modeling to meet in the proposed 2026-2027 TPP Base Case, and provides insights into the types of resources that can most effectively reduce GHG emissions to achieve California's 2045 climate goals. Studying a case that does not include a GHG target after 2035 provides an opportunity to identify the resources that are not selected in this case, compared to the lower GHG target portfolios, such as the adopted 2025-2026 TPP Base Case. Note that this scenario is for comparison purposes only and does not reflect the trajectory toward compliance with climate goals for the electricity sector through 2045. It is therefore not recommended.

[4] *See* SB 846 (Stats. 2022, Ch. 239), which added Public Utilities Code Section 712.8(q), which states: "the continued operation of Diablo Canyon Units 1 and 2 beyond their current expiration dates shall not be factored into the analyses used by the commission or by load-serving entities not subject to the commission's jurisdiction when determining future generation and transmission needs to ensure electrical grid reliability and to meet the state's greenhouse gas emissions reduction goals."

2.4. Busbar Mapping Methodology Updates

Each year, Commission staff build on the methodology used in the previous TPP cycle to map generation and storage resources to specific busbars on the transmission system. This locational analysis helps the CAISO, in its TPP analysis, understand the locations needed for potential expanded and/or upgraded transmission.

For the 2026-2027 TPP, the methodology updates include the following:

Substation-level interconnection criteria

- Integrating Participating Transmission Owner (PTO) feedback and per-unit cost guide data to estimate the economic feasibility to interconnect at individual busbars. Commission staff coordinated with the PTOs to collect and synthesize interconnection data and feedback on:
  - Existing headroom (before transmission plan deliverability (TPD) allocation);
  - Number of available interconnection positions;
  - Upgrade condition; and
  - Available area within the fence line.
- New criteria are initially used for a subset of busbars that have high demonstrated commercial interest and/or have had large mapped total resources from previously-adopted TPPs.
- Data collected from the PTOs is used to estimate interconnection cost for each busbar as a function of PTO, tie-in voltage, and feasibility.
- Substations with higher interconnection costs, including those that would require extensive upgrades or entire substations to facilitate new projects, will be de-prioritized over less expensive alternatives.
- Cost estimates across all busbars are categorized to define thresholds for criteria alignments scores.

Land-use and environmental criteria

- Replacing the Commission's High Fire Threat Districts (HFTD) dataset which is no longer being updated, with the U.S. Department of Agriculture Forest Service (USFS) Wildfire Risk to Communities dataset. To assess the fire threat to resources and transmission:
    - The NFTD maps are outdated and will not be maintained going forward, which makes them poor candidates for use in future busbar mapping cycles.
    - Among the alternative data sources reviewed, the 2024 USFS Wildfire Risk maps are a newly-published dataset from a federal agency with nationwide coverage, making it a viable option to replace the current data source.
    - Commission staff classified USFS burn probability data to align with the busbar mapping criteria alignment levels of 1-5.

CEC land-use screens development and implementation

- Updated methodology and sources of land-use and environmental criteria that information environmental evaluation:
    - The CEC Protected Area Layer, one component of the Land-Use Screens, was expanded to include coverage for CAISO-interconnecting regions of Southern Nevada and Western Arizona.

Commercial development interest

- No specific changes. Commission staff are adding clarification in the methodology document for how interconnection quantity data from neighboring balancing authority areas (BAAs) is used in the commercial interest criteria, due to confusion evidenced in stakeholder comments.

Gas capacity not retained

- Generators located within disadvantaged communities will no longer receive a blanket exemption from non-retention decisions for being among the youngest and/or most reliable units.
- Generators without any local effectiveness factor data from the CAISO Local Capacity Technical Report are now assigned the quartile scoring aligned with the lowest priority for non-retention.

Details of all of these modifications are available at the following link on the Commission's website:

https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2024-26-irp-cycle-events-and-materials/assumptions-for-the-2026-2027-tpp.

Note that stakeholders provided excellent feedback during the August 19, 2025 webinar held to discuss busbar mapping updates for this TPP cycle, as well as in informal written comments submitted after the webinar. Several ideas will be useful in the future, but could not be accommodated in this TPP cycle due to the time it would take to incorporate them. Commission staff will provide progress updates on items discussed in the August 19, 2025 webinar at upcoming webinars, workshops, or other venues to incorporate the stakeholder suggestions into future TPP cycles.

3. Procurement Need Analysis and Recommendations

This section of the ruling presents the analysis conducted by Commission staff for reliability needs on the electric system between 2028 and 2032. This analysis was conducted in response to the increase in the load forecast in the 2024 IEPR, RCPPP comments from parties, and the ACP-CA Motion to Amend the Scoping Memo in R.20-05-003.

3.1. Reliability Need Analysis

Several critical things have changed since the Commission last issued an LSE procurement order in D.23-02-040 (as modified by D.24-02-047). First, relative to prior forecasts, significant load growth is now being forecasted in 2028-2032 in the CEC's 2024 IEPR demand forecast, much of it related to data centers, continuing vehicle electrification and building electrification, and lower adoption of and lower capacity factors for behind-the-meter (BTM) solar and storage. In addition, with the passage of the OBBBA, ITC and PTC benefits are being rapidly phased out over the next few years. Federal executive orders are raising the costs of certain resources through the imposition of tariffs, particularly from Asia, and limiting or delaying siting on federal lands for some types of renewable resources. Federal financial support is also being withdrawn from some projects already approved, and for projects that the state was considering for future development. Executive Orders at the state level, particularly Governor Newsom's Order N-33-25, also indicate the need for consideration of these federal actions.

Second, as part of the CAISO interconnection queue in Cluster 14 and Cluster 15, many more projects are available than have been procured by LSEs. Some of these projects, in addition to meeting any identified need, may also be at a point in their development timelines where they could still take advantage of ITC or PTC benefits, potentially saving California ratepayers significant costs. It is difficult to determine how many projects already in Cluster 14 and 15 have sufficient access to transmission or interconnection facilities to support their development. Likewise, it is difficult to know which or how many Cluster 14 and 15 projects have obtained necessary permits and/or have access to viable equipment supply chains to take advantage of expiring tax credits.

In addition, the resource adequacy proceeding also routinely studies reliability needs, and recently increased the planning reserve margin (PRM) in light of loss-of-load-expectation (LOLE) studies in R.23-10-011. The Commission recently adopted an 18 percent PRM in the resource adequacy program for years 2026 and 2027, while also extending the effective PRM of 3-5.5 percent, in addition to the binding PRM, for those same years.

To assess whether these changes result in the need for another Commission order for capacity procurement in advance of consideration of the adoption of a programmatic framework for the RCPPP, Commission staff undertook a reliability analysis that is presented in this ruling.

In addition to the procurement considerations herein, LSEs are also responsible for resource adequacy and renewables portfolio standard (RPS) requirements. Regardless of whether the Commission orders procurement in a separate order or as part of a programmatic approach to IRP, LSEs will remain responsible for meeting multiple obligations under Sections 380, 399.11, 454.51, and 454.52.

Commission staff have prepared analysis to support both Commission and LSE decision-making and planning, with the above obligations in mind. A slide deck with more detail about the analysis is posted at the following link: https://www.cpuc.ca.gov/irp_procurement

To begin the analysis, which looks at potential reliability capacity shortfalls during the period 2028 through 2032, Commission staff began with the following basic assumptions:

- The load forecast was updated based on the 2024 IEPR assumptions.

- A number of key supply assumptions were reviewed, including assumptions related to the realization of LLT resources and DCPP status.
- The 2,000 MW NQC of LLT resources, as defined specifically and required by D.21-06-035 and D.23-02-040 to be online in 2028, but with the potential for an extension to 2031, are modeled as online in either 2028 or 2031, according to projected online data in the June 2025 Resource Data Template (RDT) filings of LSEs. In addition, based on the proposed decision in R.20-05-003 in response to the SCE Petition for Modification (PFM) of D.23-02-040 and D.24-02-047 dated August 13, 2025,[5] generic capacity was assumed to have been procured to replace any LLT capacity delayed to 2031 and is still online in 2032. This is likely an optimistic assumption, as further described below.
- No additional resources, beyond those included in LSE June 2025 IRP compliance filings, were added to meet long-term GHG goals, even though some LSEs are likely planning to procure additional resources to meet these goals.
- DCPP is modeled as offline in all years.[6]
- Electricity demand has been updated to reflect the 2024 IEPR "Planning" demand forecast, including the amount of BTM rooftop photovoltaics (PV) assumed.

[5] Available at the following link: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=575603716

[6] Public Utilities Code Section 454.52(f)(1) states: "The commission shall not include the energy, capacity, or any attribute from Diablo Canyon Unit 1 beyond November 1, 2024, or Unit 2 beyond August 26, 2025, in the adopted integrated resource plan portfolios, resource stacks, or preferred system plans." *See* also SB 846, which added Public Utilities Code Section 712.8(q), which states: "the continued operation of Diablo Canyon Units 1 and 2 beyond their current expiration dates shall not be factored into the analyses used by the commission or by load-serving entities not subject to the commission's jurisdiction when determining future generation and transmission needs to ensure electrical grid reliability and to meet the state's greenhouse gas emissions reduction goals."

- Combined heat and power (CHP) plants are not assumed to be phased out.
- Path 26 transmission is not assumed to be expanded.
- Natural gas units are not assumed to retire on any set timetable.
- No resources from the Strategic Reliability Reserve are included in the analysis.

Using this updated baseline and set of assumptions, Commission staff conducted modeling runs for the years 2028 through 2032 using the Strategic Energy and Risk Valuation Model (SERVM), which is the Loss-Of-Load-Probability (LOLP) production cost modeling software regularly used in resource adequacy and IRP reliability analyses. Commission staff performed iterative model runs to try to achieve the reliability planning standard of 0.1 LOLE, which means an expectation of one day with loss of load in ten years.[7] Unless the base portfolio was modeled to be already over-reliable, Commission staff added perfect capacity[8] (PCAP MW, which are equivalent to ELCC MW) to the model until the LOLE result was sufficiently close[9] to 0.1 LOLE.

Commission staff followed these basic steps to complete the analysis:

- Step 1: Create a 2025 NEED Determination Analysis baseline, which assumes full compliance with the IRP procurement orders.[10]

[7] D.24-02-047 adopted the 0.1 LOLE standard as the key input for determining reliability need and this is consistent with previous modeling efforts in IRP.

[8] Within SERVM, "perfect capacity" is a modeling construct to represent a perfect resource with no operating constraints, no outages, and priced to dispatch only as a last resort, to avoid unserved energy.

[9] Commission staff conducted iterative SERVM modeling runs to get to within 0.02 of the 0.1 LOLE target.

[10] D.21-06-035 and D.23-02-040, as modified by D.24-02-047. This assumption includes 100 percent compliance with those orders, which may or may not actually occur.

  - Calculate the capacity of LSE contracts as of the June 2025 IRP procurement compliance filings (no incremental RESOLVE-selected resources to meet reliability or GHG-reduction targets were included, only existing resources plus LSE-reported contracted resources);
  - Evaluate the total MTR procurement claimed by LSEs as incremental contracts beyond the existing baseline; and
  - Calibrate to the exact MTR NQC MW ordered by adding or subtracting capacity to establish the 2025 Need Determination Analysis baseline.
- Step 2: Analyze the 2025 Need Determination Analysis baseline with an LOLP model (SERVM) to determine incremental need.
  - Enter the portfolio determined in the step above into SERVM;
  - For each study year, iteratively add increasing amounts of PCAP until the resulting LOLE is approximately 0.1 (equating to one day in ten years); and
  - The PCAP added in each study year is equivalent to the ELCC MW need.
- Step 3: Analyze the impact of changes in supply or load through post-processing sensitivities
  - Sensitivities were created after SERVM modeling by changing the PCAP MW need by the change in firm capacity or by the change in managed peak (plus a 6 percent operating reserve margin).

Unlike for the development of the TPP portfolios described in Section 2 above, the need determination analysis did not involve running RESOLVE to generate an incremental build of resources to meet reliability and emissions targets at lowest cost. The study simply gathered data on the capacity associated with existing contracts as of the June 2025 IRP procurement compliance filings

and analyzed the reliability of that portfolio in SERVM, relative to a 0.1 LOLE planning standard.

Of note during the analysis of the MTR baseline used in this analysis is the fact that LSEs have reported 16.3 GW NQC (ELCC) of signed contracts, as of June 2025, to meet MTR requirements by 2028, which exceeds the 15.5 GW NQC requirement in aggregate. This quantity may not represent all LSEs being in full compliance with their IRP procurement obligations, because some LSEs have procured more than their minimum MTR requirements. LSEs may be procuring (i.e., signing contracts) with resources in excess of requirements for a variety of reasons, including anticipation of resource development delays or failures, anticipation of resource adequacy requirements, assessment of resource value, anticipation of RPS requirements, or LSE-specific portfolio objectives. The Commission has several times indicated that LSEs that procure in excess of their MTR requirements should expect to be able to count incremental additional resources towards any future needs without regards to a baseline update,[11] and this ruling proposes to continue that principle. In the staff analysis, no failure rate for contracts and no assumptions for delays were used. Thus, the capacity based on the contracted online dates may, in reality, be optimistic, and the realized incremental new capacity may be less than assumed for this analysis and/or the capacity is assumed to be online earlier than it will be in reality.

Subsequent to the modeling analysis, the proposed decision in response to the SCE PFM of D.23-02-040 and D.24-02-047 was revised and finalized, removing the proposed requirement in the original proposed decision for LSEs to be required to replace the delayed LLT resources with generic resources

[11] *See*, for example, D.23-02-040, Conclusion of Law 7, and D.25-09-007 at 35.

between 2028 and 2031.[12] Due to this change, the model's assumption that capacity from delayed LLT resources will be replaced with generic capacity is no longer correct. Thus, the analysis overstates resources by the amount of replacement capacity added, or approximately 367 MW, for all years in the analysis. In addition, if LLT resources currently expected to come online in 2028 are delayed until 2031, the analysis also overstates available resources (up to 1,633 MW) for the 2028-2030 period.

Table 7 below shows the results of the Commission staff analysis in SERVM for the original set of assumptions, referred to as the "Base Portfolio." Table 8 then displays the modeling results, adjusted by staff to reflect a minimum compliance scenario under the terms of D.25-09-007, in which all LSEs have signed contracts to satisfy their LLT resource obligations, LLT resource online dates are delayed from 2028 to 2031, and all LSEs are compliant with their system resource adequacy month-ahead requirements. Under these assumptions, 13,500 MW NQC would be assumed to come online through 2027, in accordance with D.21-06-035 and D.23-02-040 (as modified by D.24-02-047). Then, all 2,000 MW NQC of LLT resources would be assumed to come online in 2031, leading to a modeled resource build of 15,500 MW NQC. Because many LSEs have requested LLT resource extensions, this ruling proposes requiring procurement based on Table 8 below, rather than based on the originally-modeled Base Portfolio in Table 7.

[12] The final version of the decision adopted by the Commission is D.25-09-007.

Table 7. Cumulative SERVM PCAP Need Results for 2028-2032, Base Portfolio

Study Year	**LOLE**	**Expected Unserved Energy (EUE)**	**Cumulative Added PCAP**
Year	**Days/Year**	**MWh**	**ELCC MW**
2028	0.043	254	NA
2029	0.115	850	1,200
2030	0.117	755	2,300
2031	0.111	619	4,000
2032	0.098	525	5,900

Table 8. Cumulative SERVM PCAP Need Results for 2028-2032, Delayed LLT Scenario

Study Year	**LOLE**	**Cumulative Added PCAP**	**Estimated Adjustment for Delayed LLTs**	**Cumulative Added PCAP, Adjusted**
Year	**Days/Year**	**ELCC MW**	**ELCC MW**	**ELCC MW**
2028	0.043	NA	2,000	NA
2029	0.115	1,200	2,000	3,200
2030	0.117	2,300	2,000	4,300
2031	0.111	4,000	367	4,367
2032	0.098	5,900	367	6,267

Note that in years 2029-2031, as Commission staff only conducted SERVM modeling to get close to the 0.1 LOLE target but not achieve it precisely, a small amount of additional PCAP is likely needed in order to meet the standard. For 2028, staff originally found the existing resource build to be over-reliable compared to 0.1 LOLE. However, the surplus magnitude was not estimated as part of the staff analysis. Therefore, the estimate for the surplus or deficit in 2028 in the Delayed LLT Scenario adjustment is also undefined.

3.2. Reliability Sensitivity Analysis

For the post-processing sensitivity analysis, staff looked at three changes in assumptions and analyzed each using a heuristic approach, by manually adding or subtracting PCAP from the results, corresponding to the change in forecasted managed peak MW or firm MW available in each sensitivity. In assessing peak MW changes on PCAP need, an additional 6 percent operating reserves were assumed, instead of the load variability of the full PRM, since most of the load changes are not expected to have significant weather-driven variation. These scenarios were not analyzed in SERVM. Staff looked at the following sensitivity scenarios:

1. **Continued DCPP operations**: in this scenario, 2,200 MW was removed from the PCAP shortfall, using the assumption that DCPP would stay online through its current approved timeframe, which would retire Unit 1 on October 31, 2029 and Unit 2 on October 31, 2030.
   - Both units would be available for the 2028 and 2029 peak periods.
   - Unit 2 (1,100 MW) would be available for the 2030 peak period.
   - Neither unit would be available for 2031 or 2032.
2. **Increased data center load**: in this scenario, a managed peak change, plus 6 percent operating reserves, was added to the PCAP shortfall. The managed peak change was calculated by substituting in the data center load modifier from the 2024 IEPR "Local Reliability" scenario, instead of from the 2024 IEPR "Planning" scenario. No other changes from the 2024 IEPR "Local Reliability" scenario were used.
3. **Reduced load from electrification and data centers**: in this scenario, a managed peak change, plus 6 percent operating reserves, was removed from the PCAP shortfall. This sensitivity was designed to reflect potential impacts of recent policy changes, including the OBBBA, potential

repeal of the Environmental Protection Agency Waiver from the Clean Air Act potentially influencing electric vehicle adoption, and uncertainty in building electrification and data center load. Potential impacts of federal import tariffs were not included. Details of how Commission staff adjusted load components to reflect the policy changes and uncertainty are described in the slide deck available at: https://www.cpuc.ca.gov/irp_procurement. Note that this heuristic method is less precise, since the load components are more varied compared to the flat data center load changes in Sensitivity 2 above, which is more akin to a PCAP resource as modeled in SERVM.

Sensitivities 1 and 3 above reduce the PCAP need, while sensitivity 2 increases it.

Tables 9 and 10 below summarize the results of the sensitivity analyses for the Base Portfolio and the Delayed LLT Portfolio, respectively. In the Delayed LLT Scenario, upon which this ruling proposes to base a need determination, the current DCPP continued operations schedule would substantially reduce the reliability need in 2029, but the statutory directives prohibiting consideration of DCPP extensions are important and likely render this scenario not actionable at this time. Increased data center load modestly increases the need. Reduced load may substantially reduce need in all years.

Table 9. PCAP Need Results for Sensitivities Compared to Base Portfolio (MW)

Study Year	**Base Scenario**	**Increased data center load**	**Reduced load**	**Continued DCPP operations**
2028	NA	0	0	NA
2029	1,200	1,301	0	0
2030	2,300	2,544	0	1,200
2031	4,000	4,306	301	4,000
2032	5,900	6,295	1,645	5,900

Table 10. PCAP Need Results for Sensitivities Compared to Delayed LLT Portfolio (MW)

Study Year	Delayed LLT Scenario	Increased data center load	Reduced load	Continued DCPP operations
2028	NA	0	0	NA
2029	3,200	3,301	1,014	1,000
2030	4,300	4,544	1,347	3,200
2031	4,367	4,673	668	4,367
2032	6,267	6,662	2,012	6,267

3.3. Proposed Need Determination

Based on the above analysis, this ruling proposes that the Commission order additional procurement during the years 2029-2032 in the amounts shown in Table 11 below.

Table 11. Proposed Procurement To be Required from LSEs Collectively (in ELCC MW)

Year	Cumulative Procurement Required in Model (rounded to nearest 500 MW)	Incremental Procurement Recommended
2029	3,000	1,500
2030	4,500	1,500
2031	4,500	1,500
2032	6,000	1,500

The annual procurement amounts in the final column of Table 11 above are recommended for several reasons. First, for planning purposes, it is helpful for LSEs to engage in regular annual procurement to help take advantage of projects that continue to become available. In addition, ordering procurement now may help LSEs take advantage of any projects eligible for expiring federal tax credits or other incentives, such as grants or loans, that may be at risk at the federal level. A consistent amount of procurement each year will also be more

easily incorporated within a potential programmatic requirement. Finally, 2031 or 2032 may be the first compliance year to be enforceable, if some form of the RCPPP proposal is ultimately adopted, but it may be operationally challenging to incorporate a large amount of procurement need to a new program in its first year of binding operation. Thus, ordering a reasonably large tranche of procurement through the existing mechanism could help alleviate pressure on any new RCPPP structure adopted and facilitate the phase-in of the new programmatic approach, if adopted. The actual need in 2029 through 2032 may be higher or lower than proposed in Table 11, in which case any additional requirements would be binding under either the resource adequacy program and/or a new IRP program paradigm, if adopted.

Even if this ruling were not to propose procurement as shown in the final column of Table 11, there appears to be an ongoing need for incremental annual resource procurement for system reliability, regardless of how it is ordered or required. A total of 6,000 MW appears to be a reasonable amount to order under the existing framework. In the event that the load forecast is lowered in future years, some amount of this procurement may be a year or two premature, but would likely still be needed to achieve long-term goals.

It is also proposed in this ruling that the compliance baseline for these procurement amounts would continue to be that utilized in D.21-06-035. IN D.21-06-035, the Commission required that any procurement that was intended to count towards the required amounts needed to be incremental relative to the existing resources and/or the resources already under contract at that time. To extend that concept to this new potential requirement would mean that any procurement already undertaken by an LSE that exceeds its obligations from D.21-06-035 and D.23-02-040 (as modified by D.24-02-047) would be applied to

the LSE's supplemental obligation, derived from the amounts in the final column of Table 11 above.[13] Likewise, any procurement undertaken in response to this ruling (and any subsequent decision following it) would also be counted toward RCPPP requirements, if a program is ultimately adopted by the Commission.

The procurement amounts are also proposed as effective capacity amounts, in units of NQC-ELCC, consistent with past orders. Also in past orders, the Commission required staff to post the MTR-ELCC valuations for each technology type. Similarly, if procurement is ultimately ordered following this ruling, Commission staff would have to determine the ELCC valuation for each technology and each tranche of procurement. It is important to note, for example, that as additional storage is added to the system, there may be a question about the need for energy resources to generate sufficient additional electricity to charge the storage. Parties are requested to comment on this question specifically in response to this ruling.

Qualifying resources would also be the same as under D.21-06-035 and D.23-02-040. Namely, the resources would be required to be non-GHG-emitting and/or eligible for the RPS program. Only new resources (online after January 1, 2020[14]) would qualify. The rules around baseline swaps[15] would also be extended.

Most prior decisions did not allow the repowering or existing clean energy or natural gas resources to qualify to meet the procurement requirements. Given

[13] This is consistent with D.23-02-040, Conclusion of Law 7, which states: "If an LSE already has procured its share of capacity for one compliance period, it may count any excess procurement from that compliance period in future compliance periods."

[14] *See* D.23-02-040 at 21.

[15] *See* D.23-02-040, Ordering Paragraph 13.

that there are resources that will enter retirement age in the late 2020s and early 2030s, parties are also asked to comment specifically on whether repowering should be eligible to count toward "new" resources requirements, including recommendations for how such resources should verified (given that the CAISO rarely reissues new resource identifications or updates commercial online dates for repowering, which could make compliance verification challenging).

3.4. Proposed Need Allocation

This ruling proposes that the allocation of need to each LSE should be based on each LSE's share of the managed peak on the electric system as of the resource adequacy program year 2026, in the same basic manner as the procurement requirements were allocated under the MTR and Supplemental MTR orders. LSE requirements would be based on their year-ahead resource adequacy forecasts for 2026.

There are other pathways that could also be considered. Given the nature of MTR-style need allocation, particularly the added complexity of requiring every LSE to procure their share of the need, procurement could be accomplished by the investor-owned utilities (IOUs) on behalf of all LSEs, with costs allocated via the Cost Allocation Mechanism (CAM). An argument for this approach could be to maximize the opportunities to take advantage of expiring tax credits. Having a smaller number of LSEs in the market to procure could simplify the task.

Another approach could also be for the Commission to adjust the effective PRM mechanism as used in the resource adequacy proceeding, for some or all of the need determination. Parties are asked to comment on alternative approaches such as these, or others, to efficiently continue procurement to best maintain electric system reliability.

3.5. Proposed Compliance and Enforcement Processes

This ruling also proposes that compliance and enforcement processes also mirror those under the MTR and Supplemental MTR orders. First, new resources to meet the compliance requirements would be required to be online by June 1 of each year where procurement is required, via an annual tranche. Second, as stated above, the baseline would be identical to the original baseline for D.21-06-035, which builds upon the baseline originally set in D.19-11-016. Third, resources would be counted based on a set of incremental ELCC values that will be published by Commission staff. Alternatively, the Commission could extend the existing ELCC values from 2028-2032, though they may overstate the value of 4-hour storage, but compliance obligation simplicity could offset the lost precision in ELCC valuation. Finally, non-compliance would be penalized at the net cost of new entry (CONE) for any amount of ELCC MW that an LSE is short in a given year. Compliance is proposed to be assessed on an annual basis.

It is also important to note that even if the Commission orders procurement after this ruling with a certain compliance regimen, other programs, including resource adequacy, RPS, and a potential RCPPP, could end up being more binding constraints on LSE procurement.

3.6. Other Potential Commission Actions

The Commission continues to review and process advice letters proposing specific contracts, while also working closely with stakeholders and other state agencies to reduce barriers to resource development, including through the Tracking Energy Development (TED) Task Force and the Infrastructure Strike Team. Parties are invited to propose additional policy and/or administrative

actions, beyond those proposed above, that could support reliability in the 2028-2032 period, in their responses to the questions below in Section 4.

4. Questions for Parties

Parties are requested to respond to the analysis presented in this ruling and associated/linked materials on the Commission's web site in comments and reply comments. To assist parties in preparing their comments, included below is a list of questions to which parties are requested to respond. If parties wish to make comments on topics that are not covered in the below questions, parties should include those comments at the end of their submissions, to assist Commission staff in organizing the comments received.

Questions Related to the 2026-2027 TPP Recommendations

1. Please comment on the updated Framework for TPP Portfolio Selection and recommend any changes.
2. Comment on the modeling assumption updates made for this round of TPP recommendations. Are there other critical assumptions that you recommend? Be as specific as possible about assumptions and data sources.
3. Do you support the recommended Base Case for the 2026-2027 TPP? Provide rationale for your recommendation. If you prefer a different Base Case portfolio, describe it as specifically as possible.
4. Do you support the proposed Limited Wind Sensitivity for analysis in the 2026-2027 TPP? Provide rationale for your recommendation. If you prefer a different Sensitivity portfolio, describe it as specifically as possible.
5. If you have a recommendation for a lower-overall-cost sensitivity portfolio to be evaluated, please describe it in detail.
6. How could the Commission address the very high solar build rates through 2031, observed in both the recommended Base Case and Sensitivity portfolios, driven

by increased load forecasts from the 2024 IEPR and the 2030 GHG target? Do you have recommendations for alternative sensitivities that could achieve the near-term targets while mitigating risk and reducing potential costs to ratepayers? Provide rationale for your recommendations.

7. Comment on the busbar mapping methodology updates made for this round of TPP recommendations. Are there other critical updates that you recommend? Be as specific as possible about assumptions and data sources.
8. What criteria should the Commission adopt to inform mapping of EGS in California? Be as specific as possible about recommended assumptions and data sources.
9. Do you have recommendations for additional data sources to inform future updates to the commercial interest criteria, to supplement review of interconnection queue data? Be as specific as possible about assumptions, data sources, and application to busbar mapping.

Questions Related to the Procurement Need Analysis and Recommendations

10. Is another procurement order needed, as recommended in this ruling? What amount of resources (in ELCC MW NQC) should be required and for which years/tranches?
11. Should the Commission base a potential procurement order on an alternative study or rationale beyond that described in this ruling? If so, provide the study and explain why it should be used instead.
12. Comment on the impact a Commission procurement order could have on the market for the necessary resources. Provide evidence of your assertions, if possible.
13. In addition to or instead of procurement proposed in this ruling, are there other measures outside of the IRP context that the Commission should consider? If so, explain your recommendations in detail.
14. If the Commission orders procurement in the IRP proceeding between 2028-2032, should it be for generic

capacity, or should there also be an energy component (due, in part, to the declining ELCCs of battery storage)? Why or why not? Do the resource adequacy Slice of Day requirements adequately address this issue? Why or why not?

15. If energy resources are needed for 2028-2032, should the RPS program be used for procurement of additional energy resources, rather than ordering procurement in the IRP context? Provide your rationale.
16. Comment on the LLT resource delay assumptions of three years. What challenges are present in procuring these resources and bringing them online?
17. Should a procurement order, if one is issued, specify particular characteristics for resource procurement (e.g., clean firm, long-duration storage, etc.), or should the requirement be entirely for generic capacity resources?
18. Should a procurement order, if one is issued, consider relaxing any of the resource eligibility requirements associated with prior MTR orders? If so, what should be changed? Explain your rationale.
19. If a procurement order is issued, comment on how the need determination should be allocated to LSEs.
20. Given efficiencies associated with procuring at scale, should the Commission consider ordering central procurement of resources, if additional procurement is ordered? Why or why not?
21. If a procurement order is issued, should there be requirements for procurement within local capacity areas? If so, which ones, and how should this requirement be designed?
22. Should capacity accreditation be based on forthcoming incremental ELCC analysis? If you prefer another method for resource accreditation (such as extension of existing accreditation, straight-line decline, or less frequent updates to values), describe it in detail. Also describe how

resources should be submitted and processed for compliance review.

23. Should the Commission continue to use the existing MTR compliance baseline and allow LSEs who have excess procurement relative to their MTR and Supplemental MTR obligations to count their excess procurement toward any new obligations? Why or why not?

24. How should any potential new procurement order relate to a potential adoption of the RCPPP requirements?

25. What other actions should the Commission take, in conjunction with, or as a substitute for, a procurement order, to cost-efficiently promote system reliability and emissions reductions during the 2028-2032 period? Be as specific as possible.

26. What other actions should the Commission take specifically to maximize the impact of the availability of existing federal government loans or other contributions, to support energy infrastructure during the 2028 to 2031 period? Be as specific as possible.

Other

27. Please feel free to comment on any other aspect of this ruling that is not covered by the above questions.

IT IS RULED that:

1. Any party may file and serve comments in response to this ruling and the questions in Section 4 by no later than October 22, 2025.

2. Any party may file and serve reply comments in response to this ruling by no later than October 31, 2025.

Dated September 30, 2025, at San Francisco, California.

/s/ JULIE A. FITCH
Julie A. Fitch
Administrative Law Judge