

Regulatory Filings

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.

R.25-02-005

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS
ON THE PROPOSED DECISION RESOLVING TRACK TWO ISSUES**

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SUMMARY OF RECOMMENDATIONS¹

The PD should be rejected and replaced with an Alternate Decision, as set forth in Appendix A, because:

- × The PD violates section 366.2(g) by failing to fulfill the Commission’s ongoing statutory obligation to reduce the cost obligation of Later Departed Customers by the value of benefits “that remain” with bundled customers;
- × The PD violates section 1705’s requirement that Commission decisions include findings on “all issues material to the order or decision,” by failing to make any findings on how assigning the entire compliance value to current bundled customers while providing zero value to Later Departed Customers for the Pre-2019 Banked RECs satisfies the indifference mandates;
- × The PD’s finding that CalCCA’s position is untimely for failure to seek rehearing of D.11-12-018 and D.19-10-001 is legally erroneous because:
 - Section 1731(b) allows rehearing only with “respect to matters determined in the action or proceeding”; and
 - Neither Decision includes any discussion or resolution of whether Later Departed Customers would be entitled to value when current bundled customers use the RECs;
- × The PD commits legal error by finding that laches bars CalCCA’s arguments given:
 - There was no unreasonable delay as the issue has repeatedly been resolved only on an interim basis or for one proceeding only pending consideration in this proceeding, and CalCCA has consistently opposed a zero valuation; and
 - The PD’s conclusory determination of prejudice to the IOUs ignores that the IOUs were on notice of CalCCA’s position and is unsupported by record evidence of reliance.

¹ Acronyms used herein are defined in the body of this document.

The California Community Choice Association² (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure³ on the proposed *Decision Resolving Track Two Issues* (PD) in this proceeding, dated August 13, 2026.

I. INTRODUCTION

Track 2 of this Power Charge Indifference Adjustment (PCIA) proceeding is the culmination of six years of litigation over a single issue: whether unbundled customers, who paid for renewable energy credits (RECs) banked before 2019 (Pre-2019 Banked RECs) when they were bundled customers but who later departed (Later Departed Customers), are entitled under the Public Utilities Code⁴ to receive their share of benefits when the RECs are later used by the investor-owned utilities (IOUs) to satisfy Renewables Portfolio Standard (RPS) compliance obligations for current bundled customers. The PD's answer – no – rests on multiple legal errors and must be rejected.

First, the PD violates section 366.2(g) by treating indifference as a one-time determination rather than an ongoing statutory obligation to account for benefits that remain with bundled customers. Section 366.2(g) expressly requires that costs imposed on unbundled, community choice aggregator (CCA) customers “*shall be reduced by the value of any benefits that remain with bundled service customers.*”⁵ Yet the PD states that “once the Commission adopts an indifference framework, we assume the framework will achieve indifference,” and therefore the indifference achieved in Decision (D.) 11-12-018 “is all the indifference mandates required.”⁶ This result constitutes legal error in that it fails to comply with the Commission's ongoing statutory obligation to account for benefits *that remain* with bundled customers.

Pre-2019 Banked RECs present a unique timing issue because their costs and benefits can be realized by different customers at different times. When the RECs were generated, then-departed

² California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, Valley Clean Energy, and WestLight Energy.

³ *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021), as amended by *Resolution ALJ-485* (June 11, 2026).

⁴ All Section references herein are to the California Public Utilities Code unless otherwise noted.

⁵ Section 366.2(g) (emphasis added).

⁶ PD, at 32.

customers were credited through the PCIA for the value of the RECs they paid to generate, and then-bundled customers paid for those RECs in their generation rates.⁷ Indifference for then-departed customers was achieved—costs were allocated, and RECs changed hands. Some of those then-bundled customers, however, subsequently departed for CCA service and became Later Departed Customers. Although Later Departed Customers paid for the Pre-2019 Banked RECs while bundled, they never received benefits from their share of the banked RECs.

Those benefits arise when the share of the banked RECs that Later Departed Customers paid for through generation rates are used by the IOUs to satisfy current bundled customers' RPS obligations. The historical MPB credits to then-departed customers and subsequent compliance benefits for which the value must be provided to the customers that paid for them—i.e., current bundled customers and Later Departed Customers (which together were historically then-bundled customers)—are distinct benefits received by different customers at different times. Nothing in section 366.2(g) permits the Commission to disregard a benefit simply because it had not yet been realized—or could not yet be valued—when the associated costs were originally allocated. Nor does recognizing that benefit today retroactively modify D.11-12-018 or D.19-10-001. It prospectively applies section 366.2(g) to a benefit that *now remains* with current bundled customers. Unless the PCIA recognizes that value, Later Departed Customers will have paid for RECs whose present compliance value they never receive, while current bundled customers retain the entire compliance benefit *for free*. In other words, the PD would have Later Departed Customers paying for others to benefit from the costs they paid, while they receive nothing.

Second, the PD fails to make the findings required by section 1705 to support its conclusion that its resolution comports with section 366.2(g). The PD concludes that D.11-12-018 satisfied the “indifference mandates” when the renewable energy was generated and treats that historical determination as permanently resolving indifference with respect to those RECs. Without making all required findings, the PD’s conclusion lacks the factual and legal foundations required by law.

Third, the PD concludes that CalCCA’s argument is untimely, and CalCCA should have previously sought rehearing on this question. This conclusion treats the Commission’s silence in D.11-12-018 and D.19-10-001 as an affirmative determination CalCCA was required to challenge on rehearing. Section 1731(b)(1), however, permits rehearing only “in respect to matters determined” in a

⁷ Exhibit (Ex.) CCA-1 at 9:8-17.

Commission action or proceeding. Neither decision determined the issue presented in Track 2. CalCCA cannot be faulted for failing to seek rehearing of a determination the Commission never made.

Fourth, the PD’s laches conclusion cannot be reconciled with the Commission’s own treatment of this issue as unresolved. The Commission repeatedly and affirmatively – *12 times* – treated Pre-2019 Banked REC valuation as an open question and ultimately dedicated Track 2 for the express purpose of resolving it. CalCCA litigated that issue through the very process the Commission created. The Commission cannot now characterize CalCCA’s argument as unfairly delayed because the Commission itself repeatedly treated the issue as unresolved.

Ultimately, the PD fails to provide Later Departing Customers the value of benefits for which they have paid. In fact, the PD’s first Finding of Fact (FOF) reveals a bias the PCIA statutory framework precludes. This Finding describes the Legislature as “delegat[ing] to the Commission the task of creating a cost recovery and allocation framework *to ensure bundled customer indifference*. . . .”⁸ Nowhere in any of the FOFs, Conclusions of Law (COL), or Ordering Paragraphs (OP) does the PD recognize that the Legislature, through sections 366.2, 366.3, and 365.2, *also* delegated to the Commission the task of preventing cost shifts between bundled and unbundled customers. Whether the omission of unbundled customers in FOF 1 is inadvertent or not, it captures the fundamental error that permeates the PD: indifference is not a one-way ratchet protecting bundled customers from cost shifts while permitting cost shifts to CCA customers. The Commission must fulfill the *entire* statutory mandate and protect *both* groups of customers from cost shifts.

Given the legal errors, the PD should be rejected and replaced with an Alternate PD that either values or allocates the Pre-2019 Banked RECs, as set forth in Appendix A.

II. SECTION 366.2(G) REQUIRES THE COMMISSION TO CREDIT TO LATER DEPARTED CUSTOMERS THE CURRENT BENEFITS OF PRE-2019 BANKED RECS RETAINED BY BUNDLED CUSTOMERS

The costs and benefits associated with Pre-2019 Banked RECs must be equitably allocated to prevent cost shifts as required by section 366.2(g). As set forth below, the PD: (1) fails to recognize section 366.2(g)’s ongoing requirement to ensure indifference between unbundled and bundled customers; (2) errs by characterizing the later compliance benefit as duplicative when the historical MPB credit and later compliance benefit account for different benefits to different customers, at different times; (3) fails to account for the benefits remaining with bundled customers by concluding

⁸ PD, FOF 1 at 48 (emphasis added).

that D.11-12-018 permanently satisfied the indifference mandates for all future scenarios; (4) characterizes CalCCA's arguments as a request to modify D.11-12-018 and D.19-10-001, rather than the application of section 366.2(g) prospectively to a benefit being realized in the present; and (5) fails to recognize that a Pre-2019 Banked REC used to satisfy current bundled RPS compliance provides a benefit whose value must be accounted for under section 366.2(g).

A. Section 366.2(g) Requires the Commission to Ensure Ongoing Indifference

The PD violates section 366.2(g) by treating indifference as a one-time determination rather than an ongoing statutory obligation to account for benefits *that remain with* bundled customers. Typically, the allocation of PCIA costs and benefits between bundled and unbundled customers occurs within one ratemaking year.⁹ That is, a resource generates in year X, producing energy/Resource Adequacy (RA)/RPS value in year X, and customers pay the year X cost; the ERRA Forecast/PCIA process allocates these year X costs and year X market values between bundled and unbundled customers.¹⁰ Banking a REC, however, preserves the REC's compliance benefit for use in a later compliance year. The Commission has repeatedly recognized this temporal distinction. For example, D.19-10-001's treatment of post-2018 banked RECs assigns no PCIA market value to an unused banked REC when it is generated, but recognizes its market value when it is subsequently used for bundled RPS compliance. Thus, even though Pre-2019 Banked RECs are subject to a different valuation methodology, the Commission has recognized that the generation and later compliance use of a banked REC are temporally distinct valuation events.

As noted in the PD's FOF 1, "[t]he Legislature . . . did not specify [in the indifference statutes] how or over what time frame costs must be allocated or benefits remaining with bundled load must be reflected in PCIA rates."¹¹ Section 366.2(g) has no temporal requirement that costs and benefits have to occur simultaneously, and does not limit the benefits that must be recognized to those realized in the same year the underlying costs were incurred.¹² Instead, it broadly requires CCA customers' costs to be

⁹ Note that the determination in one ERRA forecast year is subject to true-up in the following ERRA forecast case.

¹⁰ See *id.*

¹¹ PD, FOF 1, at 48.

¹² That omission is significant because other provisions of section 366.2 expressly prescribe the relevant timeframe when the Legislature intended to do so. For example, section 366.2(f)(2) requires CCA customers to reimburse the IOU for electricity contract costs attributable to the customer "for the period commencing with the customer's purchases of electricity from the [CCA], through the expiration of all then existing electricity purchase contracts entered into by the [IOU]." See Section 366.2(f)(2).

reduced by the value of “any benefits *that remain with* bundled service customers.”¹³ The Commission therefore cannot disregard a benefit merely because it is realized after the associated costs were incurred.

Despite this, the PD concludes that D.11-12-018 satisfied the indifference requirements for Pre-2019 Banked RECs *before the compliance benefits at issue here were ever realized*. This result contravenes section 366.2(g) and perpetuates the cost shift that the statute prohibits.

B. The PD Erroneously Characterizes Recognition of the Later-Realized Compliance Benefit as a Duplicative Payment

The PD wholly ignores the unique timing of Pre-2019 Banked RECs and the resulting impact on Later Departed Customers. Instead, it summarily concludes that “bundled customers . . . satisfied the indifference mandates, including section 366.2(g), when [they] credited departing load the market value of Pre-2019 Banked RECs in the years they were generated, in compliance with the indifference methodology adopted in D.11-12-018.”¹⁴ It therefore erroneously characterizes recognition of the later compliance benefit as requiring bundled customers to “credit the PCIA *again* when these RECs are used for bundled compliance[,]” and concludes that requiring bundled customers to pay an “*additional* cost to use the RECs now would violate the indifference statutes.”¹⁵

These characterizations are wrong. There is *no duplicative payment* because the historical MPB credit and the later compliance benefit account for different benefits, to different customers, at different times. The historical MPB credit accounted for the market value of the RECs in the year they were generated and ensured that then-departed customers were paid the costs of those RECs under the methodology adopted in D.11-12-018. It did not compensate customers who were still bundled when the RECs were generated and banked — and therefore still paying their share of the costs—but who departed before those RECs were later used for bundled RPS compliance. Indeed, those Later Departed Customers could not have received the historical PCIA credit because *they were still bundled customers at the time*.

The distinction is critical. Compliance with D.11-12-018 in the generation year does not eliminate the separate requirement of section 366.2(g) to account for benefits that “remain with bundled service customers.” Under the PD, the entire later-realized compliance benefit remains with the IOUs, providing the IOUs with a windfall in that they get to keep the Later Departed Customers’ share of the RECs for their bundled customers *for free*. Section 366.2(g) does not permit that result. Providing Later

¹³ Section 366.2(g) (emphasis added).

¹⁴ PD, COL 1, at 51.

¹⁵ PD, at 3, 11 (emphasis added), and COL 3-4, at 51-52.

Departed Customers their share of the benefit does not credit them “again”; it credits them for a benefit they paid for but never received.

C. The Commission Cannot Presume D.11-12-018 or D.19-10-011 Satisfied Section 366.2(g) Without Determining Whether Benefits Remaining with Bundled Customers are Accounted For

The PD attempts to satisfy section 366.2(g)’s requirements by relying on the Commission’s adoption of D.11-12-018 and D.19-10-001. The PD notes that “[t]he Legislature delegated to the Commission the task of creating a cost recovery and allocation framework to ensure bundled customer indifference. . . .” and that “[o]nce the commission adopts an indifference framework, *we assume the framework will achieve indifference.*”¹⁶ The PD then concludes that “*all the indifference mandates required*” was the payment in the years the renewable resources were generated because “[d]eparting load’s PCIA rates contemporaneously decreased by the remaining benefits of those resources as determined by the commission – their market values – satisfying 366.2(g).”¹⁷ The PD’s analysis stops there.

But adoption of that cost allocation methodology is not itself evidence that the Commission has accounted for all benefits section 366.2(g) requires it to allocate. The PD’s conclusion that the Commission need not prospectively adjust its methodology to address a benefit realized years later that was never accounted for contravenes section 366.2(g). When that occurs, the Commission must modify that methodology to comply with the statute. Indeed, the Commission has done exactly that before, including in D.18-10-019, when it modified the PCIA methodology to create a true-up,¹⁸ and in the recent Track 1 Decision, when it modified the RA benchmark.¹⁹ Decision 11-12-018 did not achieve indifference for Pre-2019 Banked RECs because the decision did not contemplate or address the issue. The statutory requirement controls the methodology – not the other way around.

In addition, the PD’s reliance on D.19-10-001 and the Working Group Report leading up to it for the proposition that valuation of Pre-2019 Banked RECs was discussed and “undisput[ably] resolved” is legal error. The PD states that CalCCA acknowledged that Pre-2019 Banked RECs were already “fully

¹⁶ PD, at 32, and FOF 1, at 48 (emphasis added).

¹⁷ PD, at 32 (citing JIOU-02 at 17); *see also* FOF 8, at 49, and COL 1, at 51.

¹⁸ D.18-10-019, COL 1, at 156 (“The Commission’s current PCIA methodology leads to outcomes that are inconsistent with the requirements of Sections 365.2 and 366.3 . . . and should be revised as specified in this decision.”).

¹⁹ D.25-06-049, COL 1, at 33 (“The Commission’s current RA MPB calculation methodology leads to outcomes that are inconsistent with the requirements of Sections 365.2 and 366.3 and should be revised as described in this decision.”).

allocated” through the D.11-12-018 cost allocation methodology in the Report from the Working Group Report (co-led by CalCCA and PG&E) that states that Pre-2019 Banked RECs “have already been bought and paid for by bundled customer[s] at previous years’ RPS Adders.” In addition, the PD notes that Pre-2019 Banked RECs were exempted from the Commission’s post-2018 methodology adopted in D.19-10-001. Therefore, the PD surmises that “allocating an additional cost to bundled customers to use these RECs would violate indifference mandates.”²⁰ However, neither the Working Group Report nor D.19-10-001 actually addressed precluding the non-zero valuation of benefits accruing for Later Departed Customers when the IOUs later use Pre-2019 Banked RECs for their bundled customer RPS compliance. They were both silent on the issue and cannot be used now to support the PD’s claims that the indifference mandates had already been fully satisfied.

D. Accounting for the Compliance Value of Pre-2019 Banked RECs When that Benefit is Realized is a Prospective Application of Section 366.2(g)

The PD claims that what CalCCA is really arguing is “that the Commission erred in D.11-12-018 and that the pre-2019 PCIA methodology *should have* entitled Later Departed Customers to some future value for the Pre-2019 Banked RECs under the indifference mandates. It did not.”²¹ This argument puts words in CalCCA’s mouth. CalCCA does not contend that D.11-12-018 was erroneous when issued. The decision simply did not contemplate Later Departed Customers, which makes sense. Future departed load was uncertain. Direct access was capped, and the one CCA that existed in 2011, Marin Clean Energy, had just narrowly survived PG&E’s statewide ballot proposition aiming to stop the CCA movement. Another CCA did not form until three years later. CalCCA did not even exist at that time. The PD itself recognizes “the Commission did not recognize Later Departing Load in D.11-12-018.”²²

The PD further states that “the alleged cost shift CalCCA seeks to rectify pursuant to section 366.2(g) *existed under the pre-2019 framework*.”²³ But there was no cost shift that occurred under the pre-2019 methodology vis-à-vis these RECs. The relevant benefit had not yet been realized. The compliance benefit arises *today* when an IOU uses a Pre-2019 Banked REC to satisfy its current bundled customers’ RPS compliance obligation. CalCCA seeks recognition of *that* benefit when it is realized, as section 366.2(g) requires. The PD acknowledges both the “remaining benefits” of RPS resources and

²⁰ PD, at 37.

²¹ PD, at 35 (emphasis added), and FOF 14, at 50.

²² PD, at 35.

²³ *Ibid.* (emphasis in original).

that “PCIA rates must be offset” by those benefits.²⁴ Yet it concludes that because D.11-12-018 did not establish a mechanism through which customers departing in later years would receive their share of those subsequently realized benefits, no such value may be recognized now.²⁵ That again reverses the statutory hierarchy. The absence of a historical methodology for allocating a benefit that would be realized in the future cannot override section 366.2(g)’s requirement to account for a benefit when it *remains with* bundled customers. As the PD itself recognizes, “[t]he Commission has the discretion to make modifications to the PCIA effective on a prospective basis.”²⁶

Nor does prospective recognition of the compliance benefits require the Commission to revisit the historical rates established under D.11-12-018. Those rates remain undisturbed. CalCCA does not seek to recalculate the market value assigned to Pre-2019 Banked RECs in their generation years, refund amounts collected under historical PCIA rates, or compensate customers for a historical cost shift. It seeks to account for a different benefit being realized *now*: the use of Pre-2019 Banked RECs to satisfy current bundled customers’ RPS compliance obligations.²⁷ Applying section 366.2(g) to that current benefit is prospective, not retroactive.

E. The Commission Cannot Recognize that Pre-2019 Banked RECs Satisfy Current Bundled RPS Compliance While Assigning that Compliance Benefit Zero Value Under Section 366.2(g)

Finally, the Commission cannot reasonably recognize that Pre-2019 Banked RECs satisfy a current RPS compliance obligation while simultaneously treating the benefit of that compliance as having zero value for purposes of section 366.2(g). When an IOU removes a Pre-2019 REC from the bank and uses it for current bundled customer RPS compliance, that REC satisfies a compliance obligation that otherwise must be satisfied with other RPS procurement. The banked REC provides a present compliance value to bundled customers, even though the costs associated with acquiring that REC were originally paid pre-2019 by both current bundled customers and Later Departed Customers. The PD’s zero-value result therefore cannot be reconciled with the statute, and should be rejected.

²⁴ *Id.*

²⁵ PD, at 36, and FOF 5, at 49.

²⁶ PD, at 35; *see also* Section 1708 (“The Commission may at any time . . . rescind, alter, or amend an order or decision made by it.”).

²⁷ Indeed, this answers the question raised by the PD in footnote 110 as to why CalCCA “does not contest the appropriateness of the use of prior market values to compensate departing load under the pre-2019 methodology...” A different benefit must now be realized.

III. THE COMMISSION FAILED TO MEET SECTION 1705 REQUIREMENTS TO MAKE FINDINGS AND CONCLUSIONS ON ALL ISSUES MATERIAL TO THE DECISION

The PD fails to make the findings required by section 1705 to support its conclusion that assigning the entire compliance value to current bundled customers while providing zero value to Later Departed Customers for Pre-2019 Banked RECs satisfies the statutory indifference requirements today. Section 1705 requires that Commission decisions “contain, separately stated findings of fact and conclusions of law . . . on *all issues material to the order or decision*.”²⁸ The California Supreme Court has stated that “[e]very issue that must be resolved to reach [an] ultimate finding is ‘material to the order or decision.’”²⁹ The Commission therefore must make the requisite findings upon which that ultimate conclusion rests.³⁰ Such findings “afford a rational basis for judicial review,” allowing a reviewing court to do more than “only guess at how” a conclusion was reached.³¹ An ultimate conclusion supported only by “bare-bones conclusory findings” is insufficient because the findings must disclose the factual and analytical basis for the Commission’s determinations.³²

The PD fails to make adequate findings directly addressing the indifference requirements. The Commission does not find that the ongoing indifference requirements of section 366.2(g) have been satisfied for Later Departed Customers and that those customers have received value for the benefits remaining with bundled customers. Neither does the Commission find that Later Departed Customers did not “experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.”³³ The only related FOF that speaks directly to the cost shift – rather than the alleged delay in bringing the claim – is as follows:

FOF 4. . . . The Commission did not recognize “Later Departing Load” as a customer group in D.11-12-018 in any way.

FOF 9. The alleged cost shift CalCCA is attempting to rectify pursuant to . . . section 366.2(g) existed under the pre-2019 framework.

The PD therefore states that the cost shift only occurred pre-2019, and it was implicitly addressed in 2011 and again in 2019, despite failing to recognize Later Departed Load as a customer group.

The PD’s COL likewise are insufficient and, again, fail to address Later Departed Customers.

²⁸ Section 1705 (emphasis added).

²⁹ *California Motor Transp. Co. v. Pub. Utils. Comm’n* (1963) 59 Cal.2d 270, 273.

³⁰ *Id.* (citations omitted).

³¹ *Id.* at 274 (citations omitted).

³² *Toward Utility Rate Normalization v. Public Utils. Comm’n* (1978) 22 Cal.3d 529, 540; *California Motor*, 59 Cal.2d at 273; *Greyhound Lines, Inc. v. Pub. Utils. Comm’n* (1967) 65 Cal.2d 811, 813.

³³ Sections 366.3, 365.2.

COL 1. Bundled customers of SDG&E, SCE, and PG&E satisfied the indifference mandates, including section 366.2(g), when bundled customers credited departing load the market value of Pre-2019 Banked RECs in the years they were generated, in compliance with the indifference methodology adopted in D.11-12-018.

COL 4. Because the indifference mandates were satisfied under the pre-2019 methodology, to require current bundled customers to pay an additional cost to use the resources for which costs have already been allocated under the pre-2019 methodology would violate the indifference mandates.

The PD's characterizations result in a sidestepping of the inquiry necessary to answer the "issues material to the . . . decision": whether unbundled customers, who paid for Pre-2019 Banked RECs when they were bundled but who later departed, are statutorily entitled to receive their share of benefits when the RECs are later used to satisfy the RPS compliance obligations of current bundled customers. The PD therefore fails to satisfy the requirements of section 1705 and should be rejected.

IV. THE PD'S UNTIMELINESS FINDING IS INCONSISTENT WITH SECTION 1731(B)(1) BECAUSE CALCCA COULD NOT HAVE CHALLENGED A MATTER THE COMMISSION NEVER DETERMINED

The PD recasts CalCCA's position from seeking indifference *today* under section 366.2(g) into an attempt to reverse the alleged indifference treatment of Pre-2019 Banked RECs in D.11-12-018 and D.19-10-001.³⁴ In doing so, the PD concludes not only that those decisions already satisfied the indifference mandates, but also that CalCCA's position is untimely because CalCCA failed to seek rehearing of those decisions pursuant to section 1731(b)(1).³⁵ The PD's conclusion fails because neither D.11-12-018 nor D.19-10-001 *actually determined* the indifference treatment applicable when Pre-2019 Banked RECs are later used for bundled customer RPS compliance. The Commission was silent on that issue, and CalCCA and its CCA members could not have sought rehearing of determinations the Commission never made.

The PD attempts to transform that silence into an affirmative determination. It states that, "at the time [the Commission] adopted the decision that required bundled customers to pay for RECs in the year they were generated and that omitted credits for customers who were not yet departing load," the Commission knew those RECs could be banked and was aware of the statutory requirement to prevent cost shifts.³⁶ The PD then reasons that "[y]et the Commission's 2011 decision did not adopt a framework that required the RECs to be valued again in the year the RECs are used to satisfy bundled

³⁴ See PD, at 38, and FOF 14, at 50.

³⁵ See PD, at 37-39, FOF 15-16, at 50, COL 6, at 52.

³⁶ PD, at 41-42.

customer compliance obligations to impact additional value to Later Depart[ed] Load.”³⁷ Therefore, from what D.11-12-018 *did not adopt*, the PD concludes that CalCCA is now seeking redress for customers allegedly “*rendered not indifferent under prior methodologies . . .*”³⁸

That reasoning conflates the absence of a determination with an affirmative determination. The fact that D.11-12-018 did not adopt a mechanism for recognizing the future compliance value of Pre-2019 Banked RECs does not mean it affirmatively determined that such value must be zero. D.11-12-018 did not address what value, if any, should be recognized when these RECs are later used for bundled customer RPS compliance. Nor did D.19-10-001 or the Working Group Report leading up to it make or address that determination. The PD therefore supplies determinations never made and faults CalCCA and its members for failing to challenge them years ago.

Section 1731(b)(1) allows rehearing only with “respect to matters *determined* in the action or proceeding.”³⁹ California Supreme Court and Commission precedent distinguish matters actually determined from issues an earlier decision simply did not address. Where a prior decision includes no meaningful discussion of an issue and resolution of that issue was not necessary to the decision, its silence cannot later be converted into an affirmative determination.⁴⁰ The Commission itself has rejected precisely that type of inference, concluding that a prior decision’s silence on an issue “can not reasonably be construed to establish Commission policy.”⁴¹ Indeed, adoption of the PD’s policy would create a dangerous precedent, requiring parties to seek rehearing every time the Commission could have addressed an issue, but didn’t.

Neither D.11-12-018 nor D.19-10-001 determined that Later Departed Customers would receive zero value when Pre-2019 Banked RECs are subsequently used for bundled customer RPS compliance. Nor was such a determination necessary to either decision. The fact that D.11-12-018 addressed the value recognized in the year RECs were generated did not require the Commission to determine the treatment of a distinct compliance benefit realized years later. In addition, neither D.19-10-001 nor the

³⁷ PD, at 42 (emphasis added).

³⁸ *Ibid.*

³⁹ Section 1731(b)(1).

⁴⁰ See *People v. Gray* (2023) 15 Cal.5th 152 (declining to read an earlier Supreme Court opinion as establishing a requirement where “the question was not before us”); see also *People v. Sims* (1982) 32 Cal.3d 468, 484 (“An issue is actually litigated ‘[w]hen [it] is *properly* raised, by the pleadings or otherwise, and is submitted for determination, and is *determined* . . .”).

⁴¹ D.07-12-021.

Working Group Report addressed how to maintain indifference for Later Departed Customers when those Pre-2019 Banked RECs are subsequently used.⁴²

CalCCA and its members had no determination on this issue that they could challenge on rehearing. Its Track 2 position cannot be deemed untimely for failing to challenge a determination that did not exist. The PD also cannot supply that determination now and retroactively fault CalCCA for failing to challenge it years earlier. The PD's untimeliness conclusion, and the PD, should be rejected.

V. THE COMMISSION'S REPEATED TREATMENT OF PRE-2019 BANKED REC VALUATION AS AN UNRESOLVED ISSUE CONFIRMS THAT CALCCA'S CLAIM IS NOT BARRED BY LACHES

CalCCA and its member CCAs have diligently and consistently pursued the argument that all customers who paid to generate Pre-2019 Banked RECs used for bundled customer compliance must receive their share of the benefits of those RECs. The record in this proceeding and the multiple prior proceedings in which this issue was disputed demonstrate that these arguments are timely, ripe, and appropriate for decision on the policy merits in *this* proceeding.

Nevertheless, the PD erroneously adopts the Joint IOUs' argument that laches bars CalCCA from raising its claims in this proceeding because CalCCA and its members failed to file for rehearing of D.11-12-018 or D.19-10-001.⁴³ Laches is an equitable doctrine that prevents a party who has 'slept on their rights' from raising them too late in a way that is unfair to another party.⁴⁴ Laches, therefore, requires both "unreasonable delay" and a resulting "prejudice" (or acquiescence).⁴⁵ The reasonableness of an alleged delay is a fact-based question that turns on what a party "knew or with reasonable inquiry should have known."⁴⁶ Neither unreasonable delay nor prejudice occurred here, resulting in legal error through the PD's finding that laches bars CalCCA's arguments.

A. Unreasonable Delay Does Not Exist Because Neither D.11-12-018 Nor D.19-10-001 Resolved the Question of Pre-2019 Banked REC Value, and Only Recently Did the IOUs Start Predicting the Need to Use Pre-2019 Banked RECs

As a threshold matter, CalCCA's claim regarding Pre-2019 Banked RECs cannot be characterized as unreasonably delayed. CalCCA has challenged the Joint IOUs' proposals to value Pre-

⁴² In fact, SCE filed an Application for Rehearing on the exact question of whether D.19-10-001 conclusively determined the value of Pre-2019 Banked RECs when used for RPS compliance, and the Commission punted, leaving the ambiguity to be resolved in a later rulemaking. *See* D.24-08-004, at COL 3-4.

⁴³ PD, at 40.

⁴⁴ D.15-05-004, at 22.

⁴⁵ *See* 24 Cal.4th 61, at 68; *see also* D.15-02-040, at 7.

⁴⁶ *See* D.95-02-016, at COL 4-5.

2019 Banked RECs at zero in all Commission proceedings in which the question has been at issue, and the issue has never been resolved. For laches to apply, CalCCA must have been on notice that the Commission believed the issue had already been decided. The actions of CalCCA, other parties, and the Commission itself demonstrate it was reasonable to consider this issue unresolved, and that this rulemaking forum is the appropriate forum in which to address this question. None of the Commission's twelve prior decisions addressing this issue suggested that the issue had already been decided.

The Commission's statements in ERRA cases demonstrate the reasonableness of CalCCA's position that this question had not been previously addressed. The Commission regularly declines to decide issues that are not ripe,⁴⁷ and declines to decide open policy questions in the ERRA cases.⁴⁸ That occurred as recently as December for these RECs, when the Commission continued its pattern of deciding the Pre-2019 Banked REC question on "interim" or "for this case only" grounds.⁴⁹ In PG&E's 2026 ERRA Forecast Decision, for example, the Commission found "that PG&E's proposal [to value Pre-2019 Banked RECs at zero] is reasonable *on an interim basis* while awaiting a more comprehensive decision on use of banked RECs in a rulemaking."⁵⁰ That Decision explicitly found that D.19-10-001 "did not conclusively resolve how to value pre-2019 RECs," and adopted PG&E's proposal "on an interim basis for the purpose of this decision" because the question was complicated, the subject of "conflicting understandings" and "appropriate for consideration in a rulemaking."⁵¹

The PD also acknowledges but erroneously disregards that the Commission has already granted the identical relief CalCCA is asking for (i.e., valuation of Pre-2019 Banked RECs at the RPS MPB) three times (PG&E's 2023, 2024, and 2025 ERRA Forecast decisions).⁵² This conclusion is inconsistent with any finding that CalCCA's claim is stale, abandoned, untimely, or unreasonably delayed. How could the Commission have found that CalCCA's proposal resulted in just and reasonable rates in these

⁴⁷ D.18-11-005, at 4 (citing D.18-05-050, at 3).

⁴⁸ OIR, at 10 ("the [2026 Energy Resource Recovery Account (ERRA)] process itself is intended to function as an individual electric IOU's annual forecast and accounting review, not as a forum for evaluating or setting policy.")

⁴⁹ D.25-12-028, at 111-113, COL 14 (treating resolution as "interim"); D.25-12-027, at FOF 15 ("on an interim basis for the purpose of this decision"); D.24-12-039, at 68 (approving treatment "for this proceeding"); D.24-08-004, at 5 (denying SCE's Petition for Modification and saying the Commission "may consider the issue in a future rulemaking"); D.23-11-094, at 60 (treating resolution as "interim").

⁵⁰ D.25-12-027, at 26.

⁵¹ D.25-12-027, at 31.

⁵² PD at 42.

three decisions and then now decide that the matter had already been clearly resolved to *prevent* such treatment over a decade ago?

Additionally, the Joint IOUs only recently started considering the need to use Pre-2019 Banked RECs. And while the PD notes that “actual harm is not a condition precedent to challenging a Commission decision,”⁵³ it is clear that parties and the Commission were working together to delay the consideration of the issue to this rulemaking. The Commission even ordered the IOUs to exhaust Post-2018 Banked RECs before turning to Pre-2019 Banked RECs.⁵⁴ In every proceeding in which this issue was explicitly raised, CalCCA opposed valuing Pre-2019 banked RECs at a zero-dollar valuation. Now the issue has finally come to a head. Indeed, the Scoping Memo launching this Track 2 characterized the Pre-2019 Banked REC valuation question as one that had “emerged as exigent.”⁵⁵ Characterizing CalCCA’s position as unreasonably delayed therefore ignores the facts and should be rejected.

B. The PD’s Determination of Prejudice Ignores that the Joint IOUs Were on Notice of CalCCA’s Arguments and is Unsupported by Record Evidence of Reliance

The PD also erroneously adopts the Joint IOUs’ laches argument by finding prejudice to the IOUs by CalCCA failing to earlier raise its claims. This finding, however, ignores the history of this dispute and prior positions, and relies on unsupported factual claims. First, the Joint IOUs have been aware that CalCCA and its members have considered this a disputed issue for years and have consistently raised their arguments in applications and rulemakings. The PD claims that CalCCA’s alleged delay “prejudiced other stakeholders” because those stakeholders lost their opportunity to “advocate for the redress of other past cost shifts” and because they “made procurement, allocation, and market offer decisions.”⁵⁶ But the IOUs made their decisions while on notice that CalCCA considered this matter disputed for all the reasons described *supra*. The IOUs – like the CCAs – made procurement, allocation, and market offer decisions under conditions of uncertainty as this issue remained unresolved.

In fact, the Joint IOUs themselves claimed that the valuation of banked RECs was a live issue as recently as 2023. In R.17-06-026 (and after D.19-10-001) the parties responded to an ALJ request for them to identify what issues remained to be addressed. In SCE’s Comments in response, it included:

How the IOUs should account for the use of banked Renewable Energy Credits (RECs) for RPS compliance. Stakeholders have observed that there is no guidance on how the IOU should account

⁵³ PD at 41.

⁵⁴ *See, e.g.*, D.23-11-094, COL 5-7, OP 9.

⁵⁵ R.25-02-005, *Amended Scoping Memo* (Feb. 3, 2026), at 2.

⁵⁶ PD, at 41.

for its use of banked RECs for RPS compliance purposes. The underlying issue is to ensure that the value of the those banked RECs is appropriately accounted for in the IOUs' PABA, adopted in this proceeding in 2018, when and if they are used for the IOU's RPS compliance.⁵⁷

At the time, CalCCA agreed, noting that the Commission should address questions related to “the value that will be placed on the RECs, and specific methodologies for tracking excess RECs and whether they have been previously charged to customers.”⁵⁸ PG&E's Reply Comments also agreed with SCE, stating that SCE's Comments “correctly recognize that there is no guidance on banked REC accounting.”⁵⁹ The Joint IOUs' claim of laches is therefore itself untimely, and they cannot demonstrate that they were prejudiced by any alleged delay. Laches is an equitable remedy, and a finding of laches is improper when the invoking party's hands are themselves not clean.⁶⁰

Lastly, the application of laches in this instance runs counter to the practice CalCCA reasonably believed the Commission employs in rulemakings: permitting parties to raise legal and policy arguments as to how the Commission can accomplish its statutory and constitutional obligations prospectively. CalCCA was unable to find any historical instance in which the Commission used laches to reject a party's argument made through testimony and briefing in a rulemaking. The PD's reliance on laches to reject to CalCCA's claims must be rejected as legally erroneous.

VI. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and respectfully requests adoption of the recommendations proposed herein. For all the foregoing reasons, the PD should be rejected and replaced with an Alternate PD that either values or allocates the Pre-2019 Banked RECs, as set forth in Appendix A.

⁵⁷ *Opening Comments of SCE on ALJ's Ruling Requesting Comments on Supplemental Greenhouse Gas-Free Proposal and Issues in Scope*, R.17-06-026 (Nov. 7, 2022), at 4.

⁵⁸ *CalCCA's Comments on ALJ's Ruling Requesting Comments on Supplemental Greenhouse Gas-Free Proposal and Issues in Scope*, R.17-06-026 (Nov. 7, 2022), at 15.

⁵⁹ *Reply Comments of PG&E to Administrative Law Judge's Ruling Requesting Comments On GHG-Free Resources Supplemental Energy Division Staff Proposal and Issues in Scope*, R.17-06-026 (Nov. 7, 2022), at 5.

⁶⁰ D.15-02-040, at 7 (“Laches is an equitable doctrine, and the party invoking laches must “come with clean hands.” (13 Witkin, Summary of Cal. Law (10th ed. 2005) Equity, § 9; see *Precision Instrument Mfg. Co. v. Automotive Maintenance Machinery Co.* (1945) 324 U.S. 806, 814 (unclean hands “closes the doors of a court of equity to the one tainted with inequity or bad faith relative to the matter in which he seeks relief”).

Respectfully submitted,

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September 2, 2026

**APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS
ON THE PROPOSED DECISION RESOLVING TRACK TWO ISSUES**

**PROPOSED CHANGES TO FINDINGS OF FACT,
CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS**

All Findings of Fact, Conclusions of Law, and Ordering Paragraphs in the Proposed Decision shall be rejected and replaced with the following:

FINDINGS OF FACT

1. The Legislature delegated to the Commission the task of creating a cost recovery and allocation framework to prevent cost shifts between bundled and unbundled customers and did not specify how or over what time frame costs must be allocated or benefits remaining with bundled load must be reflected in PCIA rates.
2. RECs generated by the investor-owned utilities prior to 2019 and subsequently banked present a unique timing issue because their costs and benefits can be realized by different customers at different times.
3. In D.11-12-018, the Commission revised the PCIA market price benchmark to incorporate an adder to reflect the market value of RPS-compliant renewable resources in the PCIA.
4. Before 2019, when RECs were generated by PCIA resources, customers that had already departed bundled service were credited through the PCIA for the value of the RECs they paid to generate.
5. Before 2019, then-bundled customers paid for all of the RECs generated by the IOUs' PCIA resources in their generation rates, as required by D.11-12-018. If the investor-owned utility did not need the RECs at that time to satisfy the RPS compliance needs of their bundled customers, the investor-owned utility could bank the RECs for later use.
6. After paying for the RECs in generation rates, some then-bundled customers subsequently departed for CCA service and became Later Departed Customers.
7. IOU bundled customers receive benefits from Pre-2019 Banked RECs when the IOUs use those RECs to satisfy a portion of these bundled customers' RPS compliance obligations.
8. These benefits arise from both the share of Pre-2019 banked RECs that current bundled customers paid for through generation rates and from the share of the Pre-2019 banked RECs that Later

Departed Customers paid for through their own generation rates when they were bundled customers.

9. Although Later Departed Customers paid for the Pre-2019 Banked RECs while bundled, they never received benefits from their share of the banked RECs.
10. The historical MPB credit to then-departed customers and the subsequent compliance benefit retained by current bundled customers are not duplicative; they are distinct benefits received by different customers at different times.
11. Recognizing the benefits to current bundled customers when the IOUs remove Pre-2019 Banked RECs from the bank and use them for RPS compliance, and providing to Later Departed Customers the value of the share of those benefits for which they paid, satisfies the requirement of Section 366.2(g) that benefits that remain with current bundled customers be credited or allocated to Later Departed Customers.
12. Unless the PCIA recognizes that value, Later Departed Customers will have paid for RECs whose present compliance value they never receive, while current bundled customers retain the entire compliance benefit for free, resulting in a cost shift to Later Departed Customers.
13. Crediting the value of—or allocating—Pre-2019 banked RECs to the customer vintage of the year in which a REC was banked provides benefits to all customers who paid for those RECs in proportion to their load (including current bundled customers), and does not provide any new PCIA credit to customers who departed before those RECs were banked.

CONCLUSIONS OF LAW

1. Section 366.2(a)(4) requires that the implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation.
2. Section 366.2(f) requires customers purchasing electricity from a community choice aggregator to reimburse the electrical corporation that previously served the customers for net unavoidable electricity costs attributable to that customer.
3. Section 366.2(g) requires that estimated net unavoidable costs paid by the customers of the community choice aggregator shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.
4. The Commission has a statutory obligation to ensure ongoing indifference between bundled and unbundled customers.

5. D.11-12-018 adopted a PCIA methodology governing the allocation of costs and benefits of RECs between then-bundled customers and already departed customers at the time of generation of the REC.
6. To prevent a cost shift to Later Departed Customers in violation of Sections 366.2(a)(4) and (g), the Commission must ensure customers that departed bundled service after a REC was generated prior to 2019 receive value, when that REC is removed from the bank by the investor-owned utility to be used for RPS compliance on behalf of its current bundled customers.
7. Requiring current bundled customers to compensate Later Departed Customers for the use of Pre-2019 Banked RECs that were originally paid for by Later Departed Customers does not constitute an unlawful shifting of costs to current bundled customers.
7. The Commission should value Pre-2019 Banked RECs at the current Renewables Portfolio Standard Market Price Benchmark for the purpose of calculating Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company's annual Power Charge Indifference Adjustment indifference amounts.

ORDERING PARAGRAPHS

1. Renewable Energy Credits generated prior to January 1, 2019, and banked shall be valued at the current Renewables Portfolio Standard Market Price Benchmark for the purpose of calculating Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company's annual Power Charge Indifference Adjustment indifference amounts.

[Alternatives to 1.:

1. *Renewable Energy Credits generated prior to January 1, 2019, and banked shall be allocated proportionate to the payment made by Later Departed Customers for those Renewable Energy Credits when they were bundled customers, via a decrement to the applicable load-serving entities' Renewables Portfolio Standard procurement need.]*
2. The methodology adopted in this decision shall be effective immediately and shall be incorporated into each investor-owned utility's 2027 Energy Resource Recovery Account October updates, impacting 2026 true-ups and 2027 forecasted rates.
3. Rulemaking 25-02-005 remains open.

This order is effective today.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.

R.25-02-005

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS
ON THE PROPOSED DECISION RESOLVING TRACK TWO ISSUES**

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September 8, 2026

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SUMMARY OF RECOMMENDATIONS¹

The Commission should reject the PD, decline the Joint IOUs' requested modifications, and adopt an alternate decision that either values or allocates the Pre-2019 Banked RECs, as set forth in Appendix A to CalCCA's Comments, because:

- The Joint IOUs misstate section 366.2(g) by treating indifference as a determination completed in 2011 rather than the Commission's ongoing obligation to account for "any benefits that remain" with bundled customers, and there is no duplicative payment because the historical market price benchmark credit and the later compliance benefit are distinct benefits, received by different customers at different times;
- The Joint IOUs' proposed new COL 8 would compound the PD's error under section 1731(b)(1), which permits rehearing only as to "matters determined," and their proposed revision to FOF 9 relabels rather than fills the gap left by the PD's failure to make the findings section 1705 requires;
- The Joint IOUs establish neither element of laches, because the Commission repeatedly resolved Pre-2019 Banked REC valuation only on an interim basis pending this rulemaking, and the Joint IOUs themselves told the Commission in 2022 that there was "no guidance" on banked REC accounting; and
- The PD's zero valuation violates section 453's prohibition on preferences, prejudice, and unreasonable differences by treating similarly situated customers arbitrarily and unfairly.

¹ Acronyms used herein are defined in the body of this document.

The California Community Choice Association (CalCCA) submits these Reply Comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure (Rules) on the *Proposed Decision Resolving Track Two Issues*² (PD), dated August 13, 2026.

I. INTRODUCTION

The Joint IOUs' Comments ask the Commission to do more than adopt a legally erroneous PD - they ask it to harden and perpetuate the PD's most consequential legal errors.³ *First*, the Joint IOUs propose to treat indifference as an obligation discharged in 2011, rather than the ongoing statutory duty Public Utilities Code section 366.2(g) imposes.⁴ *Second*, they ask the Commission to add a Conclusion of Law (COL) declaring CalCCA's claim untimely and to amend Finding of Fact (FOF) 9 to double down on describing the cost shift as a mere "allegation" - changes that deepen, rather than cure, the PD's failure to make the findings section 1705 requires. Neither request can be reconciled with controlling statutes or the record. As explained in CalCCA's Comments, the Commission should reject the PD which affirms the Joint IOUs' claims that it would be arbitrary to ensure Later Departed Customers receive the benefit of the Pre-2019 Banked Renewable Energy Credits (RECs) they paid for. In rejecting the PD, the Commission can also avoid two kinds of arbitrary, unreasonable, and unfair discrimination which the PD adopts wholesale from the Joint IOUs' prior arguments that violate section 453.

The Commission should adopt CalCCA's recommendations set forth in its Comments and issue an alternate decision adopting the FOF, COL, and ordering paragraphs in Appendix A of CalCCA's Comments.⁵

II. INDIFFERENCE UNDER SECTION 366.2(G) IS AN ONGOING OBLIGATION, NOT AN EVENT COMPLETED IN 2011

The Joint IOUs contend that the pre-2019 methodology "accounted for the market value of the [Renewables Portfolio Standard (RPS)] resources that generated the pre-2019 banked RECs in setting the PCIA rates in full satisfaction of the statutory indifference mandate."⁶ That misstates the law and the facts. Section 366.2(g) contains no temporal limitation; it requires that the net unavoidable costs paid by CCA customers "shall be reduced by the value of *any benefits that remain* with bundled service

² Proposed *Decision Resolving Track Two Issues*, Rulemaking (R.) 25-02-005 (Aug. 13, 2026).

³ Joint IOU Comments, at 3 and App. A. References to Comments herein are to the Opening Comments filed on the PD in this docket on September 2, 2026.

⁴ All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

⁵ CalCCA Comments, at 15 and App. A.

⁶ Joint IOU Comments, at 1-2.

customers.” Where the Legislature intended to prescribe a timeframe in section 366.2, it did so expressly.⁷ The PD itself concedes that the Legislature “did not specify . . . how or over what time frame costs must be allocated or benefits remaining with bundled load must be reflected in PCIA rates.”⁸

The methodology approved in Decision (D.) 11-12-018⁹ did not address the benefit at issue, which is not realized until the IOUs use the RECs for bundled customer RPS compliance. The historical market price benchmark credit (equating to the market value of RECs in the year of generation) created by D.11-12-018 compensated customers who had *already* departed. It did not compensate customers who were still bundled at the time of generation and banking and who paid for those same RECs in generation rates. Some of those bundled customers, still without receiving any compensation, later departed bundled service (becoming Later Departed Customers) before the IOUs withdrew the RECs from the bank for current bundled customer RPS compliance.¹⁰ There is accordingly no duplicative payment: the historical credit and the present compliance benefit are distinct benefits, received by different customers at different times. Crediting Later Departed Customers does not pay them “again”—it pays them once, for a benefit they paid for and never received.

The Joint IOUs’ related claim that CalCCA’s proposal “would create new cost[] shifts to bundled service customers” inverts the statute.¹¹ Bundled customers are not disadvantaged when they pay for a benefit they receive. But they are treated preferentially, at Later Departed Customers’ expense, when they receive it for free. The Joint IOUs, and the PD, get the facts and law wrong.

III. THE JOINT IOUS’ REQUESTED PD MODIFICATIONS WOULD COMPOUND THE PD’S SECTION 1705 AND 1731(B)(1) ERRORS, AND IMPROPERLY BAR CALCCA’S ARGUMENT AGAINST LACHES

The Joint IOUs ask the Commission to add a COL that “CalCCA’s claim of legal error with the RPS valuation methodology in the pre-2019 or post-2018 indifference methodology is untimely under Public Utilities Code section 1731 and Rule 16.1(a).”¹² The Commission should decline. Section 1731(b)(1) authorizes rehearing only “in respect to matters *determined* in the action or proceeding.”¹³ Neither D.11-12-018 nor D.19-10-001 *determined* what value Later Departed Customers receive when

⁷ See CalCCA Comments, at 4, n.12.

⁸ PD, FOF 1, at 48.

⁹ D.11-12-018.

¹⁰ CalCCA Comments, at 5-6.

¹¹ Joint IOU Comments, at 2.

¹² *Id.* at 3, and App. A.

¹³ Section 1731(b)(1) (emphasis added).

Pre-2019 Banked RECs are later used for bundled RPS compliance. The PD concedes that “the Commission did not recognize Later Depart[ed] Load in D.11-12-018.”¹⁴ Silence on a question whose resolution was unnecessary to the decision is not a determination.¹⁵ Elevating that reasoning to a COL would require parties to seek rehearing every time the Commission *could* have addressed an issue but did not. Such a result is bad law and bad policy.

The Joint IOUs’ proposed revision to FOF 9 fares no better. Doubling down on calling the cost shift that Later Departed Customers experience “an allegation” does not supply the findings section 1705 requires on “all issues material to the order or decision.”¹⁶ “Every issue that must be resolved to reach [an] ultimate finding is ‘material to the order or decision.’”¹⁷ The material issue remains unaddressed: whether customers who paid for Pre-2019 Banked RECs while bundled are entitled under section 366.2(g) to their value when the IOUs use them for current bundled compliance. CalCCA has provided FOF that address the material issues in this Track 2 in a manner that complies with the controlling statutes.¹⁸

The Joint IOUs again erroneously assert that CalCCA’s “unjustified failure to timely raise its indifference claims resulted in unreasonable delay, acquiescence . . . and prejudices other stakeholders.”¹⁹ Laches requires both unreasonable delay and resulting prejudice.²⁰ As CalCCA’s Comments explained, neither exists here. There was no unreasonable delay. CalCCA opposed a zero valuation in every proceeding in which the question arose.²¹ The Commission itself treated this issue as unresolved, deciding it repeatedly on an “interim” basis (most recently in December, when it found that D.19-10-001 “did not conclusively resolve how to value pre-2019 RECs” and that the question was “appropriate for consideration in a rulemaking”).²² As CalCCA’s Comments explain, the Commission granted the same relief CalCCA seeks here in three PG&E Energy Resource Recovery Account (ERRA) Forecast decisions, and the Amended Scoping Memo dedicated Track 2 to this question because it had

¹⁴ PD at 35; *see also* PD, FOF 4, at 49; CalCCA Comments, at 10-12.

¹⁵ *People v. Gray* (2023) 15 Cal.5th 152 (declining to read an earlier opinion as establishing a requirement where “the question was not before us”); *People v. Sims* (1982) 32 Cal.3d 468, 484; D.07-12-021, at 20 (a prior decision’s silence “can not reasonably be construed to establish Commission policy”).

¹⁶ Section 1705.

¹⁷ *California Motor Transp. Co. v. Pub. Utils. Comm’n* (1963) 59 Cal.2d 270, 273.

¹⁸ CalCCA Comments, App. A.

¹⁹ Joint IOU Comments, at 2-3.

²⁰ D.15-05-004, at 22; *see also* D.15-02-040, at 7.

²¹ *See* CalCCA Comments, at 12-14.

²² D.25-12-027, at 26, 31, and FOF 15; D.25-12-028, at 111-113, COL 14; D.24-12-039, at 68; D.24-08-004, at 5; D.23-11-094, at 60.

“emerged as exigent.”²³ CalCCA did not sleep on its rights regarding an issue the Commission has repeatedly said it would adjudicate later in a future proceeding—*i.e.*, this proceeding.

Nor is there prejudice. The Joint IOUs made their procurement, allocation, and market offer decisions on notice that CalCCA disputed the zero valuation. Indeed, in 2022 SCE told the Commission that “there is no guidance on how the IOU should account for its use of banked RECs for RPS compliance purposes,” and PG&E agreed.²⁴ Parties that told the Commission four years ago the issue was unresolved cannot now claim reliance on its finality, and laches is unavailable to a party without clean hands.²⁵ The Joint IOUs also identify no record evidence of actual reliance, as discussed in CalCCA’s Comments.²⁶ Therefore, the Joint IOUs’ requests should be rejected.

IV. THE PD’S ZERO VALUATION VIOLATES SECTION 453’S PROHIBITION AGAINST DISCRIMINATION

The Joint IOU Comments claim that CalCCA’s proposal would be “arbitrary, unfair, and unreasonable,”²⁷ when in fact it is the PD’s adoption of the Joint IOU’s proposal that results in discriminatory rates in violation of section 453.²⁸ Section 453(a) bars a utility from “mak[ing] or grant[ing] any preference or advantage” to any person, or “subject[ing]” any person “to any prejudice or disadvantage,” as to “rates, charges, service, facilities, or *in any other respect*.”²⁹ Section 453(c) separately bars “any unreasonable difference” in those same respects “as between classes of service.”³⁰

The Joint IOUs and PD incorrectly conclude that it would be unfair and arbitrary to ensure indifference (as is required by statute) for Pre-2019 Banked RECs if the Commission does not retroactively address all other alleged indifference failures of the D.11-12-018 framework.³¹ Assuming the Joint IOUs are right that the D.11-12-018 framework structurally disadvantaged bundled load, *Later Departed Customers were still bundled load* before they departed. More fundamentally, these alleged indifference violations arose and were completed in a single year under that prior framework—unlike

²³ PD at 42; *see also Amended Scoping Memo*, R.25-02-005 (Feb. 3, 2026), at 2.

²⁴ SCE Opening Comments, R.17-06-026 (Nov. 7, 2022), at 4; PG&E Reply Comments, R.17-06-026 (Nov. 7, 2022), at 5.

²⁵ D.15-02-040, at 7 (citing *Precision Instrument Mfg. Co. v. Automotive Maint. Mach. Co.* (1945) 324 U.S. 806, 814).

²⁶ *See* CalCCA Comments, at 14-15.

²⁷ Joint IOU Comments, at 2.

²⁸ *See* CalCCA Opening Brief at 6, 33.

²⁹ Section 453(1) (emphasis added).

³⁰ Section 453(c).

³¹ Joint IOU Comments, at 2 (citing PD at COL 5).

Pre-2019 Banked RECs for which indifference was teed up under the prior framework but is being realized in violation of the indifference statutes now.

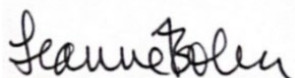
In fact, it is the PD that violates section 453 by producing unfair and arbitrary results in two ways. *First*, two groups paid the same generation rates for the same Pre-2019 Banked RECs. When an IOU withdraws those RECs for current bundled RPS compliance, the PD awards the entire compliance value to one group and zero to the other, based solely on the second group's decision to take CCA service. That is an "advantage" to one group, a "prejudice or disadvantage" to the other, and an unreasonable difference in what each pays, and receives, for the same resource.

Second, the PD unreasonably treats customers differently depending on when they departed service. Some departed customers paid to generate Pre-2019 Banked RECs that are held in the Joint IOUs' REC bank. Those RECs have exactly the same RPS compliance characteristics as RECs paid to be generated in 2020-2022 by customers who departed later or are still bundled.³² And yet the PD unreasonably and unfairly produces disparate treatment for these two groups of customers who paid for RECs that are identically situated from the RPS compliance perspective.

V. CONCLUSION

For the reasons set forth above and in CalCCA's Comments, CalCCA respectfully requests that the Commission reject the PD, decline the Joint IOUs' requested modifications, and adopt an alternate decision that either values or allocates the Pre-2019 Banked RECs, as set forth in Appendix A to CalCCA's Comments.

Respectfully submitted,



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³² See CalCCA Opening Brief at 51 (citing Vol. 1 Tr. 54:13-17; 55:4-56:22; 57:6-58:14 (Joint IOU Panel [Brown, Morien, Pulgar])).

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA**

Order Instituting Rulemaking to Improve the California Climate Credit	R.25-07-013
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**JOINT PROPOSAL OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)
AND THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION
FOR CHANGES TO CLIMATE CREDIT**

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**JOINT PROPOSAL OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)
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**JOINT PROPOSAL OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)
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JOINT PROPOSAL OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)
AND CALIFORNIA COMMUNITY CHOICE ASSOCIATION
FOR CHANGES TO CLIMATE CREDIT

Pursuant to the *Assigned Commissioner's Ruling Providing Direction and Setting the Phase 1B Procedural Schedule* dated June 20, 2026 (Phase 1B Ruling), the *Administrative Law Judge's Email Ruling Adjusting the Procedural Schedule* dated July 9, 2026 (July 9 Email Ruling), and the *Administrative Law Judge's Ruling Providing Direction for Party Proposals* dated August 17, 2026 (August 17 Ruling), Southern California Edison Company (SCE) and the California Community Choice Association (CalCCA) respectfully submit their Joint Proposal for Changes to Climate Credit (Joint Proposal).¹

I.

INTRODUCTION

SCE and CalCCA jointly propose that the Commission either retain the status quo or continue with a broadly available residential flat Climate Credit but with additional relief delivered to low-income customers. Retaining the existing equal, non-volumetric Climate Credit methodology remains the approach best supported by the record because it provides broad and predictable bill relief, minimizes implementation costs and customer confusion, and maximizes the value returned to customers. The Climate Credit is a finite pool of allowance revenues, and any redistribution necessarily involves tradeoffs: increasing the credit for one group of customers reduces the amount available to others. A departure from the status quo therefore should not be justified merely because it provides a larger credit to a particular group; it should demonstrate a net customer benefit after accounting for both the corresponding impacts on other customers and the costs of implementing the change. These considerations reinforce the benefits of the existing methodology and counsel against adopting a more complex alternative absent a demonstrated net benefit. As discussed in greater detail below, the Joint Proposal will preserve the Climate Credit as a direct and visible source of bill relief.

If, however, the Commission decides additional relief is needed for low-income customers, it could as an alternative ensure all customers continue to receive a Climate Credit distribution but also

¹ Pursuant to Rule 1.8(d), SCE confirms that counsel for CalCCA has authorized SCE to file this *Joint Proposal* on its behalf.

target incremental affordability benefits for customers facing the greatest financial pressure than other proposed changes. The Joint Proposal which incorporates this alternative balances the benefits from any changes against the complexity and associated costs and hurdles of implementation.

Specifically, if the Commission does not maintain the status quo, SCE and CalCCA jointly propose that customers who are enrolled in the California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) programs receive a Climate Credit equal to up to two times the non-CARE/non-FERA residential credit amount. Beginning with the 2028 Climate Credit distribution cycle, the Commission should adopt the following residential electric Climate Credit methodology if it decides to adopt the alternative to the status quo:

- **Credit Amount:** All eligible residential electric customers would continue to receive a Climate Credit through the Investor-Owned Utilities (IOUs), as they do today, but CARE/FERA customers will receive up to twice the Climate Credit amount provided to non-CARE/non-FERA residential customers.
- **Total Distribution:** The total amount distributed would remain limited to the applicable residential Climate Credit revenue available for distribution after any Commission-authorized deductions, transfers, administrative costs, and other applicable statutory or regulatory requirements.
- **Distribution Method:** The IOUs would continue to distribute the credit as a flat per-account bill credit, differentiated only by CARE/FERA enrollment status, and with the customer messaging approved by the Commission.
- **Distribution Timing:** Consistent with Public Utilities Code section 748.5² and the Phase 1A decision issued earlier in this proceeding,³ the IOUs will continue to distribute the credit in the highest-billed months of August and September.

If the Commission declines to maintain the status quo, it should adopt the Joint Proposal because it addresses affordability while offering a practical, administratively feasible, and customer-friendly middle ground between the current equal flat-credit structure and more complex proposals that may not offer benefits that outweigh the complexity and cost of implementation, such as those proposing to allocate Climate Credit proceeds through customer-specific usage, income, geography, or other more

² Hereinafter, unless otherwise stated, all statutory section references are to the Public Utilities Code.

³ D.26-04-036.

granular metrics. The Joint Proposal therefore should be viewed as a limited alternative to — not a reason to depart from — the status quo. The existing methodology remains the appropriate default, and the Commission should adopt the Joint Proposal only if it determines that additional targeting of affordability benefits warrants a change.

In compliance with the August 17 Ruling, which requires parties making proposals to describe the proposed change(s), explain how their proposal addresses Commission priorities, identify implementation and outreach considerations, and provide supporting data attachments, SCE and CalCCA respond to the Ruling requirements below.

II.

DETAILS OF THE PROPOSED CHANGES TO THE CLIMATE CREDIT, HOW THEY ADDRESS COMMISSION PRIORITIES, IMPLEMENTATION AND OUTREACH CONSIDERATIONS, AND DATA IN RESPONSE TO SECTION 1 OF RULING

A. The Commission Should Retain the Status Quo or, if a Change is Warranted, Adopt SCE's and CalCCA's Limited CARE/FERA Modification

The August 17 Ruling requires parties to detail their proposed changes to the Climate Credit by describing how the proposal will change the Climate Credit distribution timing, the number of distributions, methodology for calculating credit(s), and/or credit eligibility. SCE's and CalCCA's primary recommendation to retain the status quo would require no changes to any of these elements. Under the existing methodology, eligible residential customers receive an equal, flat per-account Climate Credit, with no differentiation based on usage, income, geography, or other customer characteristics, and the credit would continue to be distributed in August and September consistent with the Commission's Phase 1A decision.

Only if the Commission determines that a change to the existing methodology is warranted, SCE and CalCCA propose a limited modification that would retain the existing flat per-account structure but vary the credit amount based on whether the customer is enrolled in CARE or FERA at the time of the applicable Climate Credit distribution. The alternative would therefore preserve the principal features of the existing methodology, including its broad availability, flat per-account structure, and distribution timing, while modifying only the amount provided based on CARE or FERA enrollment.

CARE and FERA customers would receive a credit equal to up to twice the amount received by non-CARE/non-FERA residential customers. For example, if the available residential Climate Credit

revenue for a given year supports a \$100 credit for a non-CARE/non-FERA residential customer under the proposed allocation methodology, a CARE or FERA customer would receive a \$200 credit under a 2x adder. The actual credit amounts would be calculated annually based on the residential revenue available for distribution and the number of eligible residential accounts, including the number of CARE and FERA accounts. The Joint Proposal would apply to all IOUs.

1. Distribution Timing and Number of Distributions

SCE and CalCCA recommend maintaining the Phase 1A Decision's determination that the Climate Credit should be distributed in the two high-billed months of August and September.⁴

2. Methodology

SCE and CalCCA propose that the Commission calculate the residential Climate Credit using the available residential allowance revenue⁵ approved through the applicable Energy Resource Recovery Account (ERRA) Forecast, Energy Cost Adjustment Clause (ECAC), or advice letter process, less any Commission-authorized deductions, administrative costs, statutory transfers, or other applicable requirements. The remaining residential Climate Credit revenue is allocated using the formula described above.

3. Credit Eligibility

The Ruling asks parties to describe how their proposals ensure that bundled and unbundled customers are treated equally and otherwise address implementation considerations for customers whose procurement is not provided by the utility. As a preliminary matter, SCE and CalCCA jointly propose that all eligible residential electric customers continue to receive a Climate Credit. Under the alternative proposal, CARE and FERA customers would receive an enhanced credit. The Commission should direct the IOUs to use the same type of eligibility determination process they currently use for Climate Credit implementation, modified as

⁴ Decision (D.) 26-04-036, Ordering Paragraph (OP) 1.

⁵ The available residential allowance revenue is calculated as the proportionate share of total allowance revenues allocated to residential customers from the revenues available to both residential and eligible small business customers.

necessary to account for CARE/FERA status, if necessary. CARE or FERA eligibility should be determined at the time the credit is being issued by using existing CARE/FERA enrollment information in the IOUs' billing systems.⁶

SCE and CalCCA's Joint Proposal treats bundled and unbundled residential customers equally by applying to the credit to eligible residential customer accounts regardless of whether the customer receives generation procurement service from an IOU, a community choice aggregator (CCA), or another load-serving entity (LSE). This treatment is consistent with the existing Climate Credit framework, under which the residential electric Climate Credit is provided to bundled and unbundled residential electric customers.⁷ Because the alternative proposed enhanced credit is based on CARE or FERA enrollment status rather than procurement status, it does not create a distinction between bundled and unbundled customers, which is an additional benefit of the Joint Proposal as compared to some of the other more complex proposals.

The Joint Proposal also ensures that master metered customers are treated equally to non-master metered customers with respect to the distribution of the Climate Credit. Landlords are required to pass the Climate Credit on to residential master metered customers, and the Joint Proposal does not disrupt that process, ensuring compliance with Public Utilities Code section 739.5(b).

B. The Joint Proposal Furthers the Commission's Priorities

The August 17 Ruling requires parties to address how their proposals address each of the four priorities in the June 29, 2026, Phase 1B.

⁶ Note that because customers receive letters about the Climate Credit that precede the delivery of the Climate Credit, those letters may suggest to customers then served on CARE/FERA that they will receive an enhanced credit that is larger than that which they will actually receive if they are no longer on CARE/FERA when SCE delivers the Climate Credit.

⁷ OIR, p. 2 ("Per Commission decisions in Rulemaking (R.) 11-03-012 and R.20-05-002, the California Climate Credit (Climate Credit) is delivered as a twice-per-year lump-sum bill credit automatically provided to all bundled and unbundled residential electric customers and certain qualifying small business electric customers.")

1. The Joint Proposal Recommends the Affordability Benefit of the Status Quo But Provides a Limited Alternative for Additional Targeting

SCE and CalCCA contend that retaining the status quo best preserves the Climate Credit's existing affordability benefits by providing broad, predictable bill relief to all eligible residential customers without incurring additional implementation costs that would reduce the amount available for direct customer relief. If the Commission nevertheless determines that additional targeting is warranted, the alternative CARE/FERA modification would further the Commission's affordability priority by increasing the Climate Credit for customers most in need and who the IOUs can identify through their enrollment in the Commission's approved affordability programs.

Providing up to twice the Climate Credit to CARE/FERA customers under this alternative would provide greater bill relief to customers with demonstrated affordability needs while continuing to also preserve meaningful bill assistance for all other eligible residential customers, including customers who may face genuine affordability challenges but fall outside CARE/FERA eligibility. This structure recognizes that all residential customers experience energy affordability pressures, while CARE/FERA enrollment provide an existing and readily administrable means of identifying customers for enhanced support if the Commission determines that redistribution of the Climate Credit is warranted.

2. The Joint Proposal Encourages Electrification

By lowering electric bills during high-billed periods, the Joint Proposal to retain the status quo, or in the alternative to provide an enhancement for CARE/FERA customers, not only advances electric affordability for customers but also eases customer concerns that switching from fossil fuel-based to electric appliances may result in higher bills. At least for the highest billed months, a customer considering fuel switching might be encouraged towards electrification from seeing lower-than-expected bill payments due to the application of the Climate Credit during those months. In addition, if the Commission adopts the alternative proposal, applying up to twice the amount of Climate Credit to customers enrolled in SCE's CARE/ FERA programs will help increase these customers' perception that electricity is more affordable during previously high-billed months.

3. The Status Quo Promotes Fairness and the Joint Proposal Provides a Limited Alternative for Additional Targeting

The status quo promotes fairness by providing an equal Climate Credit to all eligible residential customers, recognizing that all residential customers bear Cap-and-Invest costs and that affordability challenges are not limited to customers enrolled in income-qualified programs. Maintaining that universal and equal benefit avoids choosing among customers based on imperfect proxies for financial need. If the Commission nevertheless determines that additional targeting is warranted, the proposed CARE/FERA enhancement provides a limited means of doing so by balancing universal customer participation with targeted affordability support.

The CARE/FERA enhancement would not eliminate the credit for non-CARE/non-FERA customers, many of whom may also face affordability concerns but may not qualify for CARE or FERA. At the same time, it recognizes that customers enrolled in CARE/ FERA have greater demonstrated need and should receive enhanced support. This approach avoids the potential unfairness of a purely usage-based structure, which could shift larger benefits to higher-usage customers rather than to customers with the greatest affordability need. As SCE and CalCCA have previously commented, usage-based or volumetric designs give larger benefits to higher-usage customers, rather than necessarily to those having the most trouble affording their bills.⁸ Thus, while the status quo remains the fairest approach absent a demonstrated net benefit from redistribution, the CARE/FERA enhancement provides a relatively simple and administrable alternative if the Commission determines that additional targeting is warranted.

4. The Joint Proposal is Simple

The Joint Proposal maintaining the status quo is the simplest, most efficient, and fairest result for all customers. The Joint Proposal's alternative proposal is also simple in that it relies on existing CARE/ FERA enrollment categories and preserves the flat-credit structure. As a result, the alternative proposal would be more efficient and likely less costly to implement than other proposals requiring new customer classifications, income verification systems, climate-

⁸ See SCE's Opening Comments on the Assigned Commissioner's Ruling Providing Direction and Setting the Phase 1B Procedural Schedule ("SCE Opening Comments on Phase 1B Ruling"), pp.14-15; Most recently, CalCCA Opening Comments on the Phase 1B Ruling, pp. 7, 10; CalCCA Reply Comments on the Phase 1B Ruling, p. 6.

zone targeting, census-tract targeting, household-level burden calculations, or usage-based allocation methods. SCE and CalCCA have consistently emphasized that refinements to the Climate Credit should be simple to implement and cost-effective so administrative and Information Technology (IT) costs do not erode the value of the credit.² This proposal is consistent with that approach.

5. The Joint Proposal to Maintain the Status Quo Advances All Priorities and the Alternative Proposal Provides Additional Targeting, if Warranted

The August 17 Ruling asks parties to address “whether the proposal satisfies additional priorities or principles; specifically address why it is necessary and incremental to the status quo and assigned Commissioner’s concepts.” The status quo already advances the Commission’s priorities by providing broad, transparent, and administratively simple bill relief without differentiating among residential customers or incurring the additional costs and complexity associated with a redesign. As discussed above, SCE and CalCCA therefore recommend retaining that methodology.

The status quo does not, however, provide any enhancement to address the affordability needs of low-income customers. Thus, if the Commission declines to maintain the status quo, the Joint Proposal offers a targeted and meaningful affordability focused alternative enhancement for those customers in a practical way that does not require a complex redesign the Climate Credit because it maintains the core flat-credit structure while adding a straightforward CARE/FERA enhancement. In that regard, it is simpler and more supportive of affordability than the Commission’s Concept 1 baseline usage tier approach and Concept 2 climate zone tier approach.

Concept 1 would substantially increase implementation complexity and administrative costs while providing limited additional affordability benefits. Unlike a flat-credit structure that can be readily administered using existing customer classifications, a baseline usage methodology would require utilities to calculate customer-specific credit levels based on historical electricity consumption, creating numerous operational challenges and exception cases. For example, customers who recently moved, opened new accounts, or otherwise lack a

² SCE Opening Comments on Phase 1B Ruling, p. *Id.*, pp. 15-16; CalCCA Opening Comments on the Phase 1B Ruling, pp. 7, 10; CalCCA Reply Comments on the Phase 1B Ruling, p. 6.

complete 12-month usage history would require special treatment and potentially separate calculation methodologies. In addition, tying Climate Credit allocations to baseline quantities could make the program more difficult for customers to understand, undermining the Climate Credit's role as a simple, transparent, and visible form of bill relief. SCE and CalCCA have consistently emphasized that simplicity is critical to maintaining customer awareness of and confidence in the benefits provided through the Climate Credit.¹⁰ CalCCA noted that “[u]sage-based methodologies for distributing the Climate Credit risk conflicting with established rate design, conservation, affordability, and grid reliability policies.”¹¹ Incentivizing customers to exceed their baseline usage would push customers into higher Tier-2 baseline usage rates, increasing costs to customers, not reducing them.

In contrast, if the Commission determines that a change is warranted, the Joint Proposal’s flat Climate Credit with up to a 2x enhancement for CARE/FERA customers offers a more limited departure from the status quo that directly targets bill relief to households with demonstrated affordability needs while leveraging existing program eligibility structures, supporting the Commission’s policy priorities, and preserving administrative efficiency, transparency, and implementation timing by 2028.

6. The Joint Proposal to Keep the Status Quo Preserves Simplicity and Broad Affordability, While the Alternative Proposal Provides Additional Affordability for Customers Most in Need and Simplicity for Customers and Implementation

The Joint Proposal’s recommendation to keep the status quo best preserves the values of simplicity and broad affordability by maximizing the amount available for direct customer relief and avoiding the additional costs, complexity, and redistribution inherent in any change. If the Commission nevertheless determines that additional targeting is warranted, the Joint Proposal alternative would prioritize CARE/FERA customers above non-CARE and non-FERA customers, while still providing meaningful support for both. Recognizing that low-income customers are more likely to be energy-burdened and adversely impacted by higher electricity bills than moderate- or high-income customers, the Joint Proposal provides additional support to

¹⁰ See SCE Opening Comments on Phase 1B Ruling, p.2-3; CalCCA Opening Comments on the Phase 1B Ruling, pp. 6–7; CalCCA Reply Comments on the Phase 1B Ruling, pp. 2-3.

¹¹ See CalCCA Reply Comments on the Phase 1B Ruling, p. 7.

low-income customers in a manner that is feasible to implement, simple enough to communicate to customers, and fair to other non-CARE/FERA customers. The CARE designation reasonably captures customers up to 200% of the Federal Poverty Level (FPL) and may overlap with characteristics associated with living in affordable housing or having medical needs. The Commission may also want to consider including FERA customers (who in many cases are just above the CARE threshold, earning up to 250% of the FPL).

Because the GHG allowance revenue is a zero-sum exercise, restructuring the current flat Climate Credit to give a larger credit to CARE/FERA customers would necessarily reduce the amount non-CARE/FERA customers receive. This tradeoff reinforces why the status quo should remain the Commission's default and why any departure should demonstrate a net customer benefit after accounting for both redistribution and implementation costs. Even this relatively simple alternative would impose some incremental implementation and administrative costs that could otherwise be returned directly to customers. Currently, CARE/FERA is available to customers who self-attest that they qualify based on their income or participation in certain qualifying public assistance programs and is also available to master metered customers. Because enrollment does not perfectly identify every customer experiencing affordability challenges, CARE/FERA status is an administratively useful but imperfect proxy for financial need. The Joint Proposal alternative to provide up to 2x the credit for CARE/ FERA, as opposed to a greater multiplier, generally prioritizes low-income customers without significantly reducing the amount of Climate Credit available for non-CARE and non-FERA customers, some of whom may be CARE-eligible and not yet enrolled or may be earning just above the CARE and FERA income threshold.

7. The Joint Proposal to Maintain the Status Quo Promotes Equal Treatment, While the Limited Alternative Proposal Advances Equity, Equality, Environmental and Social Justice Issues by Supporting Lower Income Customers and Promoting Electrification

The August 17 Ruling asks parties to explain “how the proposal addresses equity, equality, and/or environmental and social justice issues; whether it supports the goals and/or objectives of the Commission’s Environmental and Social Justice Action Plan 2.0.” The Joint Proposal’s recommendation to keep the status quo will advance equality by providing the same

Climate Credit to all eligible residential customers, including customers experiencing affordability challenges who may not qualify for or participate in income-qualified programs. If the Commission determines that additional targeting is warranted, the Joint Proposal alternative advances equity by providing additional benefits to customers enrolled in CARE/ FERA, while maintaining equal access to a Climate Credit for all eligible residential customers.

The Joint Proposal alternative distinguishes between equality and equity: equal treatment is preserved through universal eligibility for residential customers, while equitable treatment is advanced by increasing the benefit for customers with greater affordability needs. This structure also supports environmental and social justice objectives because low-income households are more likely to experience energy burden and bill affordability challenges. By increasing the credit for CARE and FERA customers, the proposal helps direct incremental benefits to customers most likely to need additional bill relief. Moreover, as explained above, both the status quo and the Joint Proposal alternative further electrification, which supports the state's energy and environmental policy goals.

C. Implementation Considerations

The August 17 Ruling asks parties to “provide as much detail as possible about known implementation time, cost, and complexity, including the extent to which they will be ongoing versus initial costs.” If the Commission maintains the status quo, it will introduce little to no additional implementation time, costs, or complexity. SCE is considering optional minor enhancements to the bill presentation of the credit – the cost of the changes would be less than \$500,000. If, however, the Commission declines to maintain the status quo, the Joint Proposal's alternative to give a CARE/FERA enhancement will require billing system modifications, testing, tariff updates, customer communication updates, compliance reporting, training, and internal process changes. However, because the proposal retains a flat-credit design and relies on existing CARE/FERA indicators in utility billing systems, SCE and CalCCA expect it will be significantly less complex than proposals requiring new eligibility criteria, customer-specific income verification, geographic targeting, or volumetric calculations. SCE previously explained that IT, vendor, and operational constraints limit the speed with which utilities can implement Climate Credit changes, and that adequate lead time is necessary to build, test, and implement billing system changes. For that reason, SCE and CalCCA recommend that the Commission provide final direction well in advance of the 2028 ERRR Forecast Application and implementation cycle.

The table below reflects SCE’s high-level estimates for implementing the Joint Proposal alternative. SDG&E and PG&E will have their own cost and feasibility estimates. The estimates are based on assumptions that may change and a myriad of variables. As such, a more precise estimate will be possible when SCE knows what proposal it is implementing.

ESTIMATED COST (System, ME&O, Training)	IMPLEMENTATION TIME* (Minimum)	DIFFICULTY TO IMPLEMENT** (Easy/Medium/Hard)
\$3.16M	12 Months	Medium
<i>*Estimated duration begins when the system requirements are finalized and baselined, which traditionally adds approximately two months.</i> <i>**The difficulty level determined herein considers several changes/updates that SCE will undergo to implement the Joint Proposal, including pricing changes across customer classifications, customer bill messaging based on specific climate credit amounts and customer segments.</i>		

Cost estimates are largely comprised of system implementation costs, as well as costs for marketing/communications and training. System implementation cost estimates are based on SCE’s experience with implementing similar projects and include costs to update billing system logic and reporting. Marketing/communication cost estimates (at approx. \$608K) are based on a two-part communications strategy that pairs education and notification communication to maximize awareness and customer understanding. Training cost estimates (approx. \$47K) are based on call center and billing agents training solutions for changes to the Climate Credit calculation and residential customer eligibility.

In addition to the initial implementation costs of \$3.16M, SCE anticipates ongoing cost for communication and education totaling approximately \$608K per year based on the current climate distributions in August and September. This is less than SCE estimated for any of the additional proposals that have been suggested to this point but is still an increased cost over maintaining the status quo and each additional dollar of implementation and ongoing costs are dollars that could go to customers.

1. SCE Can Implement the Joint Proposal Alternative by 2028

SCE expects that it can implement the Joint Proposal’s CARE/FERA enhancement by 2028 if the Commission issues a final decision with sufficient time for SCE to incorporate the methodology into its forecasting, billing, customer communications, tariff, and compliance processes. SCE has previously explained that Phase 1B changes would likely need to be

addressed in the 2028 ERRA Forecast application, expected to be filed in 2027.¹² Accordingly, a final Commission decision early enough to support the 2028 forecast and implementation process is important.

2. The Joint Proposal Alternative Presents Less Areas of Implementation Uncertainty

Although, as discussed below, there are areas of implementation uncertainty for the Joint Proposal alternative, SCE maintains the Joint Proposal alternative presents less uncertainty than more complex proposals requiring new eligibility criteria, customer-specific income verification, geographic targeting, or volumetric calculations.

The first area of uncertainty is if the GHG Cap-and-Invest proceeds will continue to fund administrative costs, such as implementation, education and outreach. Regardless of the source of funding, SCE cannot reasonably estimate the implementation costs that may be incurred in 2027 for the 2028 Climate Credit distribution. As a result, such costs cannot be reflected in SCE's 2027 ERRA Forecast proceeding (A.26-05-006) for purposes of forecasting 2027 California Climate Credit returns. Once the final framework is approved, SCE will record actual implementation costs in the Greenhouse Gas Revenue Balancing Account (GHGRBA) when implementation activities commence in 2027. Those recorded costs will subsequently be included in SCE's 2028 ERRA Forecast filing and be subject to Commission review and reconciliation through the annual ERRA Forecast process.

3. The IOUs Meet Weekly to Collaborate on Proposal Development

SCE meets weekly with PG&E and SDG&E on its proposal. During these meetings, SCE connects with these utilities to review and refine the current proposal. The current proposal reflects the result of these discussions. PG&E and SDG&E still maintain a preference for the status quo and have not yet endorsed the alternative proposal.

D. The Commission Should Preserve the Existing Outreach Framework

The August 17 Ruling instructs parties to describe “how the proposed Climate Credit should be explained to customers, and what changes from the communications status quo should be made.” If the

¹² SCE Phase 1A Opening Comments, p. 7.

status quo is maintained as proposed by SCE and CalCCA, the existing outreach framework should also continue to be maintained. If, however, the Commission chooses the Joint Proposal alternative to preserve the existing flat residential Climate Credit framework with a CARE/FERA enhancement, SCE and CalCCA recommend preserving the existing Climate Credit communications framework to the extent possible, with targeted updates to explain the differentiated credit amounts. SCE and CalCCA therefore recommend for both the status quo and the alternative that customer communications continue to describe the Climate Credit in clear, concise, and accurate terms, including attributing it to the state's Cap-and-Invest Program, which will ensure compliance with Public Utilities Code section 748.5(b)(2) and Title 17 California Code of Regulations section 95982(d)(6).

For the Joint Proposal alternative, a two-part communications approach would support customer awareness and understanding by pairing customer education with customer notification. The education component would provide customers with information about the Joint Proposal alternative and the revised Climate Credit structure and help address common questions before the applicable distribution period. The notification component would inform customers when the credit is applied, consistent with the current approach. Targeted customer communications would explain (1) the standard residential Climate Credit amount and that it is automatically applied to the bill as a credit to residential customers; (2) the enhanced Climate Credit amount for CARE/FERA customers without those customers having to take any action to receive their credit or enhancement; (3) that the credit comes from the state's Cap-and-Invest program; (5) how to learn more about the Climate Credit and CARE/FERA eligibility and enrollment.

These targeted updates may be delivered, as appropriate, through existing or planned Climate Credit communication channels, including bill messaging, email or letter communications, updates to SCE's and the other IOUs' Climate Credit webpages and frequently asked questions, customer service representative scripts, internal support materials, and coordination with Commission-approved statewide messaging. SCE can also coordinate with Energy Division, as appropriate, to support message consistency. CalCCA and the CCAs will also be involved with Climate Credit messaging as directed by the Commission to maintain neutral messaging.

SCE has previously emphasized that education and outreach costs are deducted from the same pool of proceeds that fund the Climate Credit, reducing the size of the credit customers receive. For that reason, communications should remain simple, coordinated, and cost-effective, and should avoid

unnecessary new communications requirements unless the record demonstrates that such requirements are necessary and cost-effective.

1. The Joint Proposal to Maintain the Status Quo or Adopt the Alternative May Encourage Electrification Without Requiring Customer Action

As discussed above, the Joint Proposal – both to maintain the status quo or adopt the alternative -- may benefit electrification by influencing customer behavior. By lowering electric bills during high-billed periods, the status quo and the Joint Proposal not only advance electric affordability for customers but also ease customer concerns that switching from fossil fuel-based to electric appliances may result in higher bills. At least for the highest billed months, a customer considering fuel switching might be encouraged towards electrification from seeing lower-than-expected bill payments due to the application of the Climate Credit during those months. In addition, applying twice the amount of Climate Credit to customers enrolled in SCE's CARE and FERA programs will help increase these customers' perception that electricity is more affordable during previously high-billed months.

At the same time, the Joint Proposal would not encourage additional usage in response to an improper price signal. Because the Climate Credit is provided as a flat, below-the-line bill credit that does not vary with consumption, customers do not receive a larger credit by using more electricity. Instead, the flat credit preserves the underlying price signal associated with incremental usage while potentially encouraging customers to use electricity more efficiently to maximize the bill-relief value of the credit.

Other than potentially driving electrification behavior in a manner that promotes the state's energy and environmental policy goals, the Joint Proposal will not be an imposition on customers that requires them to modify their behavior. The Climate Credit will continue to be applied automatically to eligible residential customer accounts, and if the Commission adopts the alternative, customers already enrolled in CARE or FERA will automatically receive the enhanced credit based on existing program enrollment information. Accordingly, outreach should focus on customer awareness and understanding, not behavior modification. Communications should make clear that:

- Eligible residential customers do not need to take action to receive the Climate Credit;

- CARE/FERA enrollment may affect the amount of the Climate Credit a customer receives under the proposed alternative structure.
- If the alternative is adopted, customers already enrolled in CARE or FERA do not need to take additional action to receive the enhanced credit; and
- If the alternative is adopted, customers who may be eligible for CARE or FERA but are not currently enrolled may review eligibility and enrollment resources.

SCE and CalCCA recommend that the Commission avoid imposing extensive new outreach requirements unless the record demonstrates that those requirements are cost-effective and necessary. This approach is consistent with SCE's and CalCCA's prior positions that Climate Credit outreach should remain simple, affordable, and coordinated across agencies and IOUs, particularly because education and outreach costs are deducted from the same allowance proceeds used to fund customer bill credits.¹³

E. Data Attachments

Below is data estimating the amount of the credit customers may receive under the alternative proposal, as compared to other potential proposals, such as a volumetric return. SCE will provide customer impact estimates in an accompanying workbook, consistent with the ALJ Ruling's direction. Compared to the purely volumetric proposal, the Joint Proposal alternative proposal provides greater and more predictable relief to lower and moderate usage CARE customers, which is consistent with the Commission's affordability priorities. The following comparison uses the volumetric credit (5.35 c/kWh) from SCE's July 17, 2026 data filing, using average low, medium, and high CARE/FERA and Non-CARE/FERA usage based on August and September usage in the data filing, and credit amounts based on the 2026 annual climate credit. Under a volumetric credit, CARE/FERA customers would have to consume at least 1,000 kWh in August and September to receive the same annual credit as the Joint Proposal. And, based on the IOUs' Data Reports filed in response to the Commission's June 29 Ruling, CARE customers would have to consume significantly more electricity than their average to receive the same credit as the Joint Proposal, which may push CARE customers beyond their baseline

¹³ SCE 9/26/25 Opening Comments on OIR, p. 6; Most recently, CalCCA Opening Comments on the Phase 1B Ruling, pp. 6–8; CalCCA Reply Comments on the Phase 1B Ruling, pp. 13–15.

Tier 1 usage allowance, increasing their rates and counteracting the Climate Credit's affordability purpose.

Table 1 Impact Estimate of Purely Volumetric Return	
Volumetric Credit (Aug/Sep)	Joint Proposal
Low: 300 kWh/month = \$35/year	Non-CARE = \$55/Year CARE = \$110/year
Medium: 600 kWh/Month = \$65/year	Non-CARE = \$55/Year CARE = \$110/year
High 1,000 kWh/month = \$110/Year	Non-CARE = \$55/Year CARE = \$110/year

SCE also provides the estimated Climate Credit payments for Concept 1 – Baseline Usage Tier Approach based on the hypothetical examples provided in the ruling and the 2026 annual climate credit.

Table 2 Impact Estimate of Concept 1: Baseline Usage Tier	
Concept 1: Baseline Usage Tier	Climate Credit
Below baseline – 1x	\$43
Above baseline (non-CARE) – 2x	\$87
Above baseline CARE – 3x	\$128

Finally, SCE also provides the estimated Climate Credit payments for Concept 2 – Climate Zone Tier Approach – based on the hypothetical examples provided in the Ruling and the 2026 annual Climate Credit.

Table 3 Impact Estimate of Concept 2: Climate Zone Tier	
Concept 2: Climate Zone (CZ) Tier	Climate Credit
Non-CARE in cool CZ and customers below baseline in any CZ – 1x	\$44
Non-CARE in moderate CZ and CARE in cool CZ – 2x	\$88
Non-CARE in hot CZ and CARE in moderate CZ – 3x	\$133
CARE in hot CZ – 4x	\$175

The primary concerns with Concepts 1 and 2 are the complexity and conflicting policy signals. First, it will be difficult explain to customers the reasoning behind the multiple factors that went into deciding how much Climate Credit they will receive, such as why the customer's historical usage determines credit level but not their usages today, or how the Climate Credit can vary simply by living

on one side or another of an arbitrary border. This complexity also means more expensive and time-consuming billing implementation to accomplish either Concept 1 or 2, which means implementation of these concepts may not be feasible in 2028.

Second, Concepts 1 and 2 conflict with existing rate design, conservation, affordability, and grid reliability policies, incentivizing customers to increase electricity usage in order to receive a greater Climate Credit – especially when such increased usage pushes a customer beyond their Tier 1 baseline usage allowance, which increases the customers electricity rate and exacerbates affordability concerns.

Further, Concepts 1 and 2 identify CARE as the driver for an additional multiplier. If the Commission determines that additional targeting of the Climate Credit is warranted, the Joint Proposal’s alternative uses this concept and provides elevated relief to CARE/FERA customers, without the complexity and implementation concerns, and without drastically reducing the credit for non-CARE customers who may be on the edge of eligibility and vulnerable. To illustrate the comparison of the Status Quo v. the Joint Proposal, Table 4 below shows what the 2026 annual climate credit.

Table 4		
Comparison of 2026 Annual Climate Credit: Status Quo v. Joint Proposal		
Customer Segment	Status Quo	Joint Proposal (CC 2x Multiplier)
Non-CARE/Non-FERA	\$72	\$55
CARE/FERA	\$72	\$110

III.

CONCLUSION

For the foregoing reasons, SCE and CalCCA respectfully request that the Commission retain the status quo for Climate Credit distribution. If, however, the Commission determines that additional targeting is warranted and that the benefits of a change outweigh the associated costs, redistribution, and implementation considerations, SCE and CalCCA recommend a single, limited modification: an enhanced Climate Credit for CARE/FERA customers. In sum, these proposals maintain the Climate Credit as a direct and visible source of bill relief, provides greater support to CARE/FERA customers (in the alternative proposal), avoids the complexity and potential unintended consequences of usage-based or highly granular allocation methodologies, treats bundled and unbundled customers equally, can be communicated clearly to customers, and is more likely to be implementable by 2028 than more complex alternatives.

Respectfully submitted on behalf of the Parties,

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Date: September 14, 2026

Attachment A

TABLE WORKBOOKS

Attachment A: Table Workbooks

Table 1 Purely Volumetric

TOU-Default-4-9pm

	2026	Aug & Sept Only
Current Rate	ECPK	Discounted Total Rate

Energy Charge - \$/kWh

Summer Season - On-Peak	0.59096	(0.05355)	0.53741
Mid-Peak	0.47101	(0.05355)	0.41746
Off-Peak	0.35285	(0.05355)	0.29930

kWh Credit Rounded

300	(\$32)	(\$35)
600	(\$64)	(\$65)
1000	(\$107)	(\$110)

The baseline concept shown reflects annual electricity usage relative to the baseline allowance and NOT based on August and September usage.

Table 2 - Concept 1: Baseline Usage Tier

300,000,000						
Concept 1: Illustrative Climate Credit						
Baseline Level	Climate Credit	Number of Accounts*	Avg Monthly Bills**	Annual CC	Multiplier	\$
Below baseline	1x	2,247,523	\$76	\$43	1.0	\$96,083,802
Above baseline Non-CARE	2x	1,365,962	\$260	\$87	2.0	\$118,838,694
Above baseline CARE	3x	664,668	\$177	\$128	3.0	\$85,077,504
Total						\$300,000,000
% Below Baseline		53%				

Table 3 - Concept 2: Climate Zone Tier

Concept 2: Illustrative Climate Credit													
Climate Zone	Customers with very low bills (i.e. lower than customers with usage at the baseline allowance level)	All other non-CARE residential customers	CARE customers										
Cool zone	1x	1x	2x										
Moderate zone	1x	2x	3x										
Hot zone	1x	3x	4x										
				300,000,000									
Number of Accounts*													
Cool zone	1,028,301	664,341	225,823	\$44	\$44	\$88	1.0	1.0	2.0	45,232,820	29,222,977	19,872,424	94,328,221
Moderate zone	457,475	285,908	123,973	\$44	\$88	\$133	1.0	2.0	3.0	20,123,373	25,159,904	16,488,409	61,771,686
Hot zone	761,747	415,713	314,872	\$44	\$133	\$175	1.0	3.0	4.0	33,507,664	55,289,829	55,102,600	143,900,093
										98,863,857	109,672,710	91,463,433	300,000,000
Avg Monthly Bills**													
Cool zone	\$67	\$234	\$147										
Moderate zone	\$78	\$271	\$171										
Hot zone	\$84	\$290	\$196										
Estimated Climated Credit													
Cool zone	\$44	\$44	\$88										
Moderate zone	\$44	\$88	\$133										
Hot zone	\$44	\$133	\$175										

*Retail Customers (Bundled and Unbundled) excluding Toudprime
**Note: Bills are for bundled customers only. The 2025 Climate Credit is excluded (an additional \$56 has been applied to the April and October bills).

Table 4: Status Quo v Joint Proposal

Default Climate Credit / year 2026 CC

Climate Zone Type	Climate Zone	Non-CARE residential customers	FERA customers	CARE customers	Zone
Non-Hot Climate Zone	Cooler Zone	\$72.00	\$72.00	\$72.00	6, 8, 16
Non-Hot Climate Zone	Median Zone	\$72.00	\$72.00	\$72.00	5, 9
Hot Climate Zone	Hotter Zone	\$72.00	\$72.00	\$72.00	10, 13, 14, 15

Joint Proposal 1x non-CARE/non-FERA; 2x CARE/FERA

Climate Zone Type	Climate Zone	Non-CARE residential customers	FERA customers	CARE customers
Non-Hot Climate Zone	Cooler Zone	1	2	2
Non-Hot Climate Zone	Median Zone	1	2	2
Hot Climate Zone	Hotter Zone	1	2	2

Customer Count

Climate Zone Type	Climate Zone	Non-CARE residential customers	FERA customers	CARE customers
Non-Hot Climate Zone	Cooler Zone	1,602,756	15,241	475,232
Non-Hot Climate Zone	Median Zone	688,161	6,544	258,479
Hot Climate Zone	Hotter Zone	1,059,186	10,072	578,327

Non-CARE/ FERA residential customers	FERA %
1,617,998	1%
694,705	
1,069,259	

CC Rev \$ 337,967,928

Concept 2, Variance 1

Climate Zone Type	Climate Zone	Non-CARE residential customers	FERA customers	CARE customers
Non-Hot Climate Zone	Cooler Zone	\$56	\$112	\$112
Non-Hot Climate Zone	Median Zone	\$56	\$112	\$112
Hot Climate Zone	Hotter Zone	\$56	\$112	\$112

CC Concept 2, Variant 1 \$ 55.97

CC Rev 337967928

Annual Bill Impact

Climate Zone Type	Climate Zone	Non-CARE residential customers	FERA customers	CARE customers
Non-Hot Climate Zone	Cooler Zone	(\$16.03)	\$39.95	\$39.95
Non-Hot Climate Zone	Median Zone	(\$16.03)	\$39.95	\$39.95
Hot Climate Zone	Hotter Zone	(\$16.03)	\$39.95	\$39.95

DOCKETED

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Project Title:	Electricity and Gas Demand Forecast
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**STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION**

IN THE MATTER OF:

*ELECTRICITY AND GAS DEMAND
FORECAST*

DOCKET NO. 26-IEPR-03

RE: IEPR Commissioner Workshop
on Energy Demand Forecast
Inputs and Assumptions

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS
ON THE IEPR COMMISSIONER WORKSHOP ON ENERGY DEMAND
FORECAST INPUTS AND ASSUMPTIONS**

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September 15, 2026

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**STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION**

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*ELECTRICITY AND GAS DEMAND
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**CALIFORNIA COMMUNITY CHOICE ASSOCIATION’S COMMENTS
ON THE IEPR COMMISSIONER WORKSHOP ON ENERGY DEMAND
FORECAST INPUTS AND ASSUMPTIONS**

The California Community Choice Association¹ (CalCCA) submits these comments pursuant to the *IEPR Commissioner Workshop on Energy Demand Forecast Inputs and Assumptions*² (Workshop), held on August 20, 2026.

I. INTRODUCTION

The California Energy Commission’s (Commission) Integrated Energy Policy Report (IEPR) Demand Forecast plays a critical role in California’s energy planning and the state’s efforts to maintain a reliable and affordable electricity system. The Demand Forecast informs a wide range of resource, transmission, and distribution planning processes, including the California Public Utilities Commission’s (CPUC) Resource Adequacy (RA) and Integrated

¹ California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale’s Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, Valley Clean Energy, and WestLight Energy.

² *IEPR Commissioner Workshop on Energy Demand Forecast Inputs and Assumptions*, CEC Docket 26-IEPR-03, (Aug. 20, 2026), <https://www.energy.ca.gov/event/workshop/2026-08/iepr-commissioner-workshop-energy-demand-forecast-inputs-and-assumptions>.

Resource Planning (IRP) proceedings, the California Independent System Operator's (CAISO) Transmission Planning Process (TPP), and investor-owned utility (IOU) distribution planning processes. Given the breadth of these applications, it is essential that the Demand Forecast appropriately balances the need to plan for future demand with the uncertainty inherent in forecasting rapidly developing loads. A forecast that is too low can create reliability risks, while a forecast that is too high can drive unnecessary procurement and infrastructure investment, ultimately increasing costs for customers. Because forecast uncertainty is inherent in any long-term demand forecast, the Commission's objective should be to account for uncertainty and use the best available information so that California can plan for the resources needed to maintain reliability without driving unnecessary costs for customers.

CalCCA appreciates the Commission's continued efforts to improve the IEPR Demand Forecast and, in particular, its increased coordination with community choice aggregators (CCA) on large-load developments. The Commission should build on these efforts by expanding engagement with CCAs and other informed stakeholders to obtain the most current and complete information available regarding prospective large loads, including their likelihood, timing, and magnitude. CCAs are uniquely positioned to provide information regarding large-load developments in their communities through their relationships with local cities, counties, and prospective customers. Incorporating CCA load forecasts and other relevant information into the IEPR process will help ensure that the Demand Forecast reflects the broadest and most informed assessment of prospective large-load development.

The rapid growth and uncertainty associated with data center loads also underscores the need for a coordinated and transparent approach to allocating procurement obligations associated with these loads. The Commission should coordinate with the CPUC to develop a formal process

for allocating RA obligations associated with data center load based on objective information regarding interconnection status, project milestones, expected timing, and the load-serving entity (LSE) responsible for serving the load. Such a process would help ensure that procurement obligations are allocated fairly and that LSEs are not required to procure resources for loads that may not materialize—or, conversely, that emerging loads are not overlooked in a manner that creates reliability risks. A transparent, milestone-based approach would also provide greater clarity regarding which loads are reflected in each forecast scenario and which LSEs are responsible for serving those loads.

Finally, the Commission should continue excluding “known loads” from the Planning Scenario and other procurement scenarios until there is sufficient confidence in their likelihood, magnitude, and timing and that they are not already reflected elsewhere in the forecast. The Commission took a well-informed and measured approach in the 2025 IEPR,³ where after thorough discussion with stakeholders, the Commission decided to exclude known loads from the Planning Scenario and the Local Reliability Scenario used for setting local RA requirements. Significant observed delays in known loads coming online over the past year have further validated the Commission’s decision. Until a sufficiently robust process is in place to establish when known loads will materialize, at what magnitude, and without duplication elsewhere in the forecast, continuing to exclude these loads from scenarios that drive procurement obligations will ensure that customers are not subject to unnecessary costs.

³ *Final 2025 Integrated Energy Policy Report*, CEC-100-2026-001 (July 2026), <https://efiling.energy.ca.gov/GetDocument.aspx?tn=271454&DocumentContentId=108996>.

In summary, the Commission should:

- Continue and expand efforts to solicit information on prospective large loads from all informed stakeholders, including CCAs, and use that information to assess the likelihood, timing, and magnitude of such loads before incorporating them into the Demand Forecast;
- Coordinate with the CPUC to establish a formal process for allocating RA obligations associated with data center load based on objective information such as interconnection status, project milestones, expected commercial operation, and the LSE responsible for serving the load; and
- Continue to exclude known loads from Demand Forecast scenarios used to establish LSE procurement obligations, including the Planning Scenario, until there is sufficient confidence regarding their likelihood, magnitude, and timing and adequate assurance that they are not already accounted for elsewhere in the forecast.

These recommendations build on the Commission’s ongoing efforts to improve the IEPR Demand Forecast and will support a forecasting process that is responsive to California’s economic development while sufficiently rigorous and credible to support long-term resource planning. By incorporating the best available information while accounting for uncertainty, the Commission can help California plan for the resources it needs to maintain reliability without imposing unnecessary procurement and infrastructure costs on customers.

II. THE COMMISSION SHOULD CONTINUE AND EXPAND EFFORTS TO SOLICIT LARGE LOAD INFORMATION FROM CCAS TO INFORM THE LIKELIHOOD, MAGNITUDE, AND TIMING OF LARGE LOADS BEFORE INCLUDING THEM IN THE DEMAND FORECAST

During the August 12, 2026, Demand Analysis Working Group (DAWG) meeting, Commission staff stated one of its objectives of the 2026 IEPR Update⁴ is to “increase engagement with utilities and CCAs.”⁵ CalCCA strongly supports this objective and appreciates the Commission’s increased coordination with CCAs on large load issues in this cycle. The

⁴ 2026 Integrated Energy Policy Report Update, <https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2026-integrated-energy-policy-report>.

⁵ Data Center Data Collection and Forecasting, Demand Analysis Working Group (Aug. 12, 2026) (DAWG Presentation), at 13, https://www.energy.ca.gov/sites/default/files/2026-08/Data_Center_Data_Collection_and_Forecasting_ada.pdf.

Commission should build on these efforts by engaging all CCAs with prospective large loads in their service territories and using the information they provide to validate the status, timing, and likelihood of those loads. Broadening this engagement would give the Commission access to additional, on-the-ground information that can help it develop a Demand Forecast that is both responsive to emerging load and sufficiently grounded in the likelihood that such load will materialize.

CCAs, utilities, large customers, and other informed stakeholders may have different—and independently valuable—information regarding the status, timing, and likelihood of a prospective large-load project. Obtaining and reconciling information from these stakeholders is therefore important to developing the most informed forecast possible. As explained by San José Clean Energy (SJCE) during the Workshop, local and state forecasts of large loads “vary widely,” and SJCE reports significant differences in Commission, CPUC, and CCA forecasts for the same territory.⁶ For example, SJCE states that, for 2028, the 2025 IEPR forecasts a **40 percent** increase in SJCE’s load, the CPUC’s 2026 IRP forecasts a **100 percent** increase in SJCE’s load, and SJCE’s internal forecast shows a **10 percent** increase in SJCE’s load.⁷ The magnitude of these differences illustrate the importance of drawing on all available sources of information when evaluating rapidly developing loads.

The Commission can reduce the risk of forecasting prospective load that ultimately does not materialize by leveraging the information available to CCAs and other stakeholders to validate large-load projects before incorporating them into the Demand Forecast. CCAs are particularly well positioned to provide this information because of their direct relationships with

⁶ *Forecasting Perspectives from San José Clean Energy* (Aug. 20, 2026) (SJCE Presentation), at 6, <https://efiling.energy.ca.gov/GetDocument.aspx?tn=272027&DocumentContentId=109700>.

⁷ *Ibid.*

customers and their ongoing engagement with the cities and counties in their service territories. These relationships can provide CCAs with current, community-level information regarding large-load development, including project status, permitting, development timelines, and other indicators of whether and when a project is likely to come online. The Commission should leverage this local knowledge as an important complement to utility and customer information when assessing the likelihood, timing, and magnitude of prospective large loads.

The value of this stakeholder engagement is particularly important in light of Federal Energy Regulatory Commission’s (FERC) concerns “that there may be speculative transmission service requests by Eligible Customers on behalf of large loads that could result in cost shifting among transmission customers.”⁸ FERC’s concern highlights the broader consequences of incorporating speculative load into forecasts that inform downstream planning and procurement. If prospective load is incorporated into the IEPR Demand Forecast without sufficient evidence that it will materialize, the resulting procurement and infrastructure decisions could cause existing customers to bear costs associated with load that ultimately does not develop. As stated by SJCE during the Workshop, “procurement orders stemming from large amounts of ‘phantom’ load could cause increased rates, price volatility, distorted investment signals, and more.”⁹ A transparent and collaborative forecast development process can mitigate this risk by allowing CCAs and other informed stakeholders to identify changes in project status, delays, or other information that may warrant adjusting the treatment of prospective loads.

The Commission should therefore ensure that its engagement extends to all CCAs with prospective large loads forecasted in their service territories. Commission staff stated during the

⁸ *Cal. Independent Sys. Operator Corp.*, 195 FERC ¶ 61,214 (2026), FERC Docket EL26-71-000 (FERC Order), at 50, para. 78, <https://www.ferc.gov/media/e-10-el26-71-000>.

⁹ SJCE Presentation, at 6.

Workshop that it plans to send data center project data requests to a subset of LSEs, including Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company, and Southern California Edison Company, several municipal utilities, and SJCE.¹⁰ While SJCE is particularly affected by forecasted data center development, other CCAs are also affected to varying degrees. Engaging all affected CCAs would provide the Commission with a more complete picture of prospective large-load development across the state and create an opportunity to validate project information using the local knowledge available to each CCA.

To facilitate this broader engagement, after receiving data request responses from the initial group of LSEs, the Commission should conduct a second round of data requests to any CCA implicated by a project identified by an IOU. This will allow the Commission to verify that the CCA and IOU information aligns before including a project in the forecast. If successive rounds of data requests are not feasible, the Commission should issue data requests to all LSEs so that the Commission has a complete data set.

III. A FORMAL PROCESS IS NECESSARY FOR ALLOCATING RA OBLIGATIONS FOR DATA CENTER LOAD BASED ON ACTUAL INTERCONNECTION INFORMATION, PROJECT MILESTONES, AND THE LSE SERVING THE LOAD

The unique characteristics of data center development warrant a distinct process for allocating associated RA obligations to LSEs. The process should allocate RA obligations only when there is sufficient certainty that a data center will come online, based on objective project milestones, and should assign those obligations to the LSE that will actually serve the load. This approach would reduce the risk of both over-procurement, which can impose unnecessary costs on customers, and under-procurement, which can create reliability risks. It also ensures that only the LSE that will serve a load bears the compliance costs associated with that load.

¹⁰ DAWG Presentation, at 12.

As discussed in Section II, increased transparency and information sharing among the Commission, CCAs, IOUs, and data center customers is essential to assessing the likelihood and timing of data center development. This information can be particularly valuable for longer-term planning, such as transmission planning, where the specific LSE serving a future data center may not yet be known and where forecast scenarios and confidence levels can appropriately capture uncertainty in system-level load growth. RA allocation presents a different challenge because it requires assigning a specific procurement obligation to a specific LSE in the near- to mid-term. For this purpose, relying solely on forecasted load or confidence factors is insufficient. A formal, milestone-based process is needed to determine when a data center is sufficiently certain to warrant an RA obligation, and which LSE should receive that obligation.

For this reason, CalCCA filed a proposal in the CPUC's Rulemaking (R.) 25-10-003 for the unique treatment of data center loads in the RA allocation process.¹¹ CalCCA's proposal would preserve the collaborative roles of the Commission and CPUC: the Commission would continue to forecast peak demand, including the portion attributable to data centers, while the CPUC would make LSE-specific adjustments for purposes of allocating RA obligations. Rather than incorporating uncertain data center load into the existing process for allocating obligations across LSEs using confidence factors, the proposal would establish a separate process that treats new data center load based on its actual development status. Specifically, the process should: (1) treat data center load separately from other forecasted load for purposes of allocating RA obligations, using actual project and interconnection information rather than relying solely on forecasted load and confidence factors; and (2) assign an RA obligation to the LSE serving a data

¹¹ See *California Community Choice Association's Track 1 Proposals*, R.25-10-003 (Jan. 23, 2026) at 3-7, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K418/596418487.PDF>; and *California Community Choice Association's Comments On Track 1 Proposals*, R.25-10-003 (Mar. 6, 2026) at 3-8, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M601/K795/601795601.PDF>.

center only after the project reaches defined milestones demonstrating a sufficient level of certainty that the load will materialize. Relevant milestones could include selection of an LSE or generation provider, execution of an interconnection agreement, commencement of construction, or other objective indicators of project advancement.

This approach would better align RA obligations with the actual development of data center projects and protect existing customers from bearing procurement costs for load that may be delayed, reduced, or ultimately not materialize. It would also reduce the risk that LSEs are assigned obligations based on assumptions about projects that remain speculative. Treating data centers individually for purposes of RA allocation allows the CPUC to account for the unique uncertainty associated with each project while ensuring that obligations are ultimately assigned to the LSE responsible for serving the load.

This proposal also avoids the need to assume which LSE will serve a prospective data center. CCAs are default providers,¹² and they are willing and able to serve data center loads in their service areas; some already do. However, the customer ultimately determines its generation service provider. A CCA's status as the default provider does not mean that every data center will elect to take CCA service. The appropriate LSE should instead be identified based on the customer's actual service choice once that information is sufficiently certain.

¹² California Public Utilities Code section 366.2(b), the statute enabling CCAs, requires any potential public agency seeking to operate a CCA to "offer the opportunity to purchase electricity to all residential customers within its jurisdiction." The statute does not explicitly require a CCA to offer non-residential service, but it does require that the CCA offer to its customers "universal access" and "equitable treatment of all classes of customers." While under the strict statutory language, a new CCA forming could have the opportunity to only serve residential customers, to the extent that a CCA offers non-residential service, the CCA is required to offer its customers universal access and equitable treatment. Currently, all operating CCAs offer non-residential service, and therefore will be the default provider to all new large loads interconnecting in their territory. Once the CCA offers service, it is bound to serve customers in its service territory subject to each customer's choice to opt out. Section 366.2(c)(2) directs that "[i]f no negative declaration is made by a customer, that customer shall be served through the community choice aggregation program."

This approach would also reduce reliance on confidence factors to address data center load for RA allocation purposes. Data center development generally has an inherently binary outcome—a project either comes online, or it does not. If a data center has a defined ramping schedules under which portions of the load come online at different times, the timing and magnitude of that ramp can also be uncertain. Confidence factors may not adequately capture this project-specific uncertainty or provide a clear basis for determining when a particular portion of a data center’s load should result in an RA obligation for a specific LSE. While confidence factors may be useful for longer-term forecasting and planning, a milestone-based process would provide a more transparent and administratively workable mechanism for aligning RA obligations with the actual development and ramping of individual data center projects.

If implementation of CalCCA’s proposed approach is delayed, the Commission should facilitate further discussion regarding how opt-out assumptions should be developed for large loads. For example, the Commission has provided data center load by CCA in gigawatt-hour but not by number of customers. Because opt-outs are based on the number of customers rather than the amount of load, providing data center information by customer count would help LSEs and the Commission develop more informed opt-out assumptions.

IV. KNOWN LOADS SHOULD CONTINUE TO BE EXCLUDED FROM THE DEMAND FORECAST SCENARIOS USED TO DRIVE LSE PROCUREMENT OBLIGATIONS UNTIL THERE IS SUFFICIENT CONFIDENCE REGARDING THEIR LIKELIHOOD, MAGNITUDE, TIMING AND ASSURANCE THAT THEY ARE NOT ALREADY ACCOUNTED FOR ELSEWHERE IN THE FORECAST

The Commission should refrain from including known loads in the Planning Scenario, and any future scenarios used to drive resource procurement, until there is sufficient confidence regarding their likelihood, magnitude, and timing and there are assurances that these loads are not already accounted for elsewhere in the forecast. Known loads are distribution-level energization requests that the Commission first incorporated into the Demand Forecast in the

2025 IEPR. After much discussion with stakeholders, the Commission decided to exclude known loads from the Planning Scenario and developed a separate Local Reliability Scenario excluding known loads, due to concerns that known load energization dates are very uncertain and that known loads may already be accounted for in other areas of the forecast.

Commission Staff's analysis of 2025 known loads data demonstrates that the Commission took a well-informed and measured approach to known loads in the 2025 IEPR by excluding known loads from the Planning Scenario. For example, Commission staff analyzed 1,900 megawatts (MW) of known loads with requested interconnection dates in 2025 in PG&E. Of these 1,900 MW, only 70 MW were completed in 2025.¹³ This energization completion rate of 2025 known loads demonstrates that the Commission took the right approach to known loads in the 2025 IEPR and avoided subjecting customers to unnecessary costs.

In fact, had the 2025 RA requirement included the additional 1,830 MW of known loads that did not come to fruition in 2025, the unnecessary RA costs would have equaled an estimated \$145 million.¹⁴ Had an LSE procured RA for this amount and the load not materialized, all of their current customers would have paid for RA that was unnecessary. To put this in perspective, the amount of unnecessary RA that would have been required would typically serve 1.8 million people but without an additional 1.8 million people to pay for it.

CalCCA continues to support this approach for the 2026 IEPR Update. The Commission's analysis of 2025 known loads demonstrates that including known loads in the forecasts used to drive LSE procurement requirements would create significant risks of stranded

¹³ See *Known Loads Preliminary Analysis* (Aug. 20, 2026), at 6, <https://efiling.energy.ca.gov/GetDocument.aspx?tn=272023&DocumentContentId=109698>.

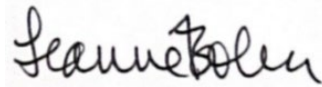
¹⁴ CalCCA used the following calculation to arrive at its estimate: the CPUC's RA market price benchmark of \$11.21/kw-month multiplied by 1000 (to convert to \$/MW-month), multiplied by 1,830 MW, multiplied by 118 percent (to account for the RA planning reserve margin), multiplied by six months (assumes the average of increased load spread equally over the year), equals \$145 million.

costs. Until there is sufficient confidence that such loads will materialize, when they will materialize, and at what magnitude, and more clarity around how much of these loads are not already accounted for elsewhere in the forecast, the Commission should exclude known loads from the Planning Scenario, and other scenarios used to drive LSE procurement obligations.

V. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the recommendations herein and looks forward to an ongoing dialogue with the Commission.

Respectfully submitted,

A handwritten signature in black ink, appearing to read "Leanne Bober", is centered below the "Respectfully submitted," text.

Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

September 15, 2026

R.25-10-003 Track 2 Workshop

Draft Results of Loss of Load Expectation Studies (LOLE)

Sep. 15, 2026



California Public
Utilities Commission

Workshop Agenda

Time	Agenda Item
10:00 AM – 10:10 AM	Welcome and Introduction
10:10 AM – 11:15 AM	Energy Division Draft LOLE Study Results
11:15 AM – 12:15 PM	CalCCA Draft LOLE Study Results
12:15 PM – 12:30 PM	CalCCA Effective PRM Presentation
12:30 PM – 1:30 PM	<i>Lunch Break</i>
1:30 PM – 2:30 PM	SCE Draft LOLE Study Results
2:30 PM – 3:30 PM	Questions and Discussion

Logistics

- All attendees have been muted.
- To ask questions, please "raise your hand"  and a moderator/presenter will unmute you so you can ask your question.
- If you would rather type, use the Q + A function and send to "all panelists". Q + A questions will be read aloud by moderators/presenters; attendees may be unmuted to respond to the answer verbally.
 - *Reminder: Please press mute when done speaking 
- Please silence and remove all AI-generated conversations and notifications to avoid cluttering the chat and Q & A forums
- Use chat only for webinar logistics questions and not substantive comments or questions.

Mute/ Unmute



Participant List



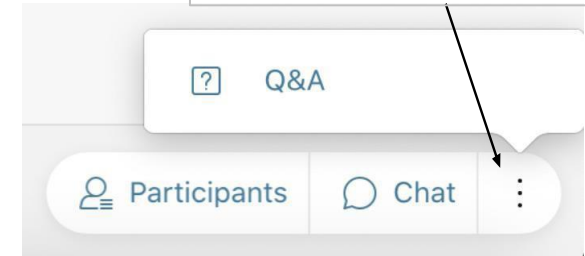
Chat



Audio Options



Q + A: on the bottom right of screen, click "3 dots"



Energy Division Draft 2028 RA LOLE Study Results

Sep. 15, 2026

Behdad Kiani, Patrick Young and Donald Brooks
Energy Resource Modeling Team



California Public
Utilities Commission

Overview of Presentation

- Objectives and Background (*Donald*)
- Summary of Results (*Behdad*)
- PRM Calibration Tool Background and Corrections Identified (*Donald*)
 - Background - Description of SOD Tool
 - PRM Calibration Tool Updates and Error Identified
 - Comparison of Previous vs. Corrected Results
- Annual LOLE Studies
 - Key Inputs (*Patrick*)
 - Methods of Calibrating LOLE (*Behdad*)
 - Results
 - Adding Demand Blocks
 - Tightening Imports
 - Prorating Capacity
- Monthly Stress Tests (*Behdad*)
 - SOD PRM results
 - UCAP vs non-UCAP PRM
- Sensitivities to Test Impact of Input Updates Since Prior Studies in 2024 (*Patrick*)
 - Update to Forced Outage Rates – switch from GADS data to CAISO data decreases reliability need
 - Econ-Demo Uncertainty – narrower distribution decreases reliability need
 - Thermal Ambient Output Derating – inclusion increases reliability need
- Conclusion and Next Steps (*Donald*)
- Questions from Stakeholders (*All*)

Objectives and Background

Objectives

- Staff hosts today's workshop to present updated results and modeling parties will present their results, to develop understanding of the analysis performed and to inform party comments.
- Staff is making this presentation, the August report, and several datasets available to parties so they can study the materials for errors or omissions, and to increase credibility of our results.
- Staff is also discussing an error identified in the Slide of Day PRM calibration tool and showing the impacts of that error on previously released study results. Staff have corrected our modeling and will release corrected results for parties to review.
- Staff seek to answer several questions, including the following:
 - What is the reliability level and achieved reserve margin of the Modeling Baseline published in June 2026 relative to the 2025 IEPR demand forecast? How long or short is the CAISO system relative to a LOLE standard of 1 event in 10 years (0.1 LOLE)?
 - Given the Slice of Day (SOD) framework, what is the monthly Planning Reserve Margin (PRM) consistent with 0.1 LOLE?
 - Does that PRM requirement depend on method of surfacing LOLE?
 - Adding demand blocks
 - Applying pro rata capacity reductions
 - How has reliability risk changed since Staff last assessed RA reliability requirements in 2024?

Background

- Energy Division staff issued the Final Inputs and Assumptions document on June 5, after reviewing and integrating party comments. Key areas revised based on party input:
 - Use narrower load forecast error distribution (based on econ-demo uncertainty from MISO study) to characterize 2028 economic and demographic uncertainty
 - Test how to surface LOLE by pro rata capacity reduction (proportional installed capacity derate across all technologies)
 - Consider less availability of imports to CAISO as non-CAISO regions may have tighter supply outlooks
 - Leave non-CAISO resource portfolio Baseline assumptions as-is (along with their implied reliability level) instead of tuning their reliability level towards 0.1 LOLE
- Staff ran LOLE models on an annual and monthly stress test basis to determine the appropriate level of reserves for 2028 and 2029 RA compliance year. 2026 and 2027 RA requirements were analyzed with a similar LOLE study performed in 2024.
- Staff modeled with updated demand and resource baselines and adopted some ideas proposed by parties (including SCE and CalCCA) to improve modeling accuracy and understand how different LOLE calibration methods may influence results
- Staff and modeling parties conducted LOLE studies in June and July
 - Staff issued a draft report on August 14. Modeling parties also filed reports on their studies on August 14.
- This workshop will be followed by a final proposal on October 13th with final modeling results.

Timeline

Step	Date
Proposed Inputs and Assumptions (I/A) issued	Apr 9
Workshop on I/A	Apr 14
Revised I/A issued	Jun 5
CPUC staff posted most data sets	Jun 15
Draft LOLE report with results issued	Aug 14
Parties filed their LOLE studies	
Workshop on LOLE study results	Sep 15
Final 2028 LOLE study report, including stress tests and PRM recommendation	Estimated Oct 13

Overview of Modeling

Staff conducted the following phases of modeling:

- **Annual LOLE studies**

Staff performed annual LOLE studies to tune modeled reliability for the CAISO BAA to 0.1 LOLE and calculated the SOD PRM for the annual peak. With updated Baseline Resources and 2025 IEPR electric demand, modeling results showed that the CAISO BAA was over reliable in 2028. Staff measured the LOLE and PRM before calibration, then calibrated LOLE towards 0.1 using the following methods in response to party comments:

- Adding flat load – Staff added a flat block of load for the whole year until 0.1 LOLE was achieved. The amount added was input to the SOD PRM Tool to calculate the summer PRM.
- Reducing Imports – Staff tightened simultaneous import limits to increase LOLE towards 0.1
- Prorating capacity – Staff reduced Pmax capacity in most unit categories (excepting hydro) by the same percentage until 0.1 LOLE was achieved. The capacity proration was input to the SOD PRM Tool to calculate the summer PRM.

- **Monthly Stress Tests and SOD translation**

Staff performed stress tests to find minimum reserve margins in off-peak months. The main goal of the stress tests was to evaluate if peak month/hour PRMs were sufficient to minimize LOLE in all months of the year. PRM levels in each month are determined in the SOD PRM Tool by inputting monthly demand and resources, then adding demand blocks until the desired PRM level is reached, then confirming with a SERVIM study to ensure LOLE across the year does not exceed the 0.1 target.

- **Sensitivities to test impacts of methodology and data changes since 2024**

Staff ran sensitivity studies to assess the impacts of modeling changes relative to the prior set of studies conducted in 2024

- Running the annual study with previous Economic and Demographic Uncertainty (EDU) distribution
- Running the annual study with previous vintage of forced outage rates
- Running the monthly stress test without thermal ambient derating

Matrix of scenarios studied (two new since August draft report)

Scenario Name	Method of Calibration to Surface LOLE	Econ-Demo Uncertainty (EDU)	Ambient Temp. Included	Maintenance Schedule Included *
Base Case	N/A	Updated	Yes	Yes
Base Case (Flat Load)	Same demand (MW) added to each month to calibrate LOLE	Updated	Yes	Yes
Base Case (Constrain Imports)	Tighten import constraints to calibrate LOLE	Updated	Yes	Yes
Base Case (Prorate Capacity)	Reduce capacity by the same percentage in each month to calibrate LOLE	Updated	Yes	Yes
Base Case (Stress Test)	Add monthly varying demand (MW) blocks to calibrate annual LOLE and levelize monthly PRM	Updated	Yes	No
Sensitivities				
Base Case (Stress Test) with Ambient Temp. Output Derating Removed	Add monthly varying demand (MW) blocks to calibrate annual LOLE and levelize monthly PRM	Updated	No	No
Base Case (Flat Load) with Prior EDU	Same demand (MW) added to each month to calibrate LOLE	Prior	Yes	Yes
Base Case (Flat Load) with Prior Forced Outage Rates	Same demand (MW) added to each month to calibrate LOLE	Updated	Yes	Yes

* Maintenance scheduling removed for monthly stress test because in practice monthly RA showings must include replacement capacity for any units that need to be on maintenance.

Summary of Results

Summary of Key Findings

- **Correction to SOD PRM Calibration Tool used for August Report:** Correcting an error in the SOD PRM Calibration Tool resulted in decline in monthly PRM by about 4 percentage points
- **Annual LOLE results:** Employing multiple means of surfacing LOLE, staff found that the CAISO Baseline resource fleet updated in 2026 is over reliable by about 5-6 GW of effective capacity:
 - Adding flat load of about 6 GW achieves 0.1 LOLE
 - Tightening the peak hour/month CAISO simultaneous import limit from 4 GW to 0 GW still results in LOLE < 0.1
 - A 95% capacity prorate (about 5.7 GW) achieves 0.1 LOLE
- **Monthly Stress Testing Results:** Adding varying blocks of demand in each month in SERVIM and then translating in the SOD PRM Calibration Tool to a monthly PRM shows that a 21% PRM is required to maintain reliability for peak months, with a lower level of 19% needed for off-peak months
- **Sensitivity Results:** Sensitivity testing of key input changes from the prior RA study show that current results are generally consistent with the prior 2024 results because changes that raised reliability risks netted out changes that lowered reliability risks
 - **Revised Econ-Demo Uncertainty Distribution:** Using a narrower economic and demographic uncertainty distribution reduces PRM about 0.6 percentage points
 - **Revised unit forced outage rates:** Using revised forced outage rates based on CAISO not GADS data reduces PRM about 1 percentage point
 - **Including Ambient Derates in modeling:** Using ambient temperature output derating for thermal power plants increases PRM about 2 percentage points
- **UCAP capacity counting results and Final Stress Test PRM**
 - Applying EFORd + Ambient Temp. derate in UCAP PRM workbook reduces monthly stress tested PRM values to 13.6% - 16.4%

2028 RA LOLE Annual Study Scenarios and Monthly Results Summary

Scenario	Conditions achieving 0.1 LOLE	LOLE Capacity (days/year)	EUE (MWh)	Monthly Reserve Margins
Base Case	n/a	0	0	34.66%-108.17%
Base Case (Flat Load)	6,000 MW flat load added	0.100	483.5	16.64%-70.93%
Base Case (Prorate Capacity), no econ-demo uncertainty	95% prorated capacity including Simultaneous Import Limits but excluding hydro capacity proration	0.091	401.7	28.13% – 98.11%
Base Case (Constrain Imports)	Tightened both 11 GW all hour and 4 GW peak hour default constraints to 0 MW all months and hours	0.014	77.0	Not calculated

Unless noted otherwise in the scenario description, all scenarios use the updated narrower econ-demo uncertainty distribution, default Simultaneous Import Limits, thermal ambient output derating, and include scheduled maintenance.

Reserve margins use current capacity value counting conventions (i.e., not UCAP).

The specific assumptions of the prorate capacity scenario that differ from other scenarios were chosen to best-effort align with assumptions used in SCE's version of a prorate capacity scenario.

2028 RA LOLE Sensitivities and Monthly Stressing Scenarios and Results Summary

Scenario	Conditions achieving 0.1 LOLE	LOLE Capacity (days/year)	EUE (MWh)	Monthly PRM
Base Case (Stress Test)	4,430 MW to 19,812 MW blocks of load added by month; no scheduled maintenance	0.101	502.8	19.00%-21.00%
Base Case (Flat Load) Prior Econ-Demo Uncertainty	5,800MW of flat load for all months	0.092	441.5	17.18%-71.96%
Base Case (Flat Load) Prior Forced Outage Rates	5,600MW of flat load for all months	0.098	551.4	17.72%-73.00%
Base Case (Stress Test) No Ambient Temp. Derate	5,136 MW to 20,604 MW blocks of load added by month; no scheduled maintenance	0.091	418.6	19.00% all months

Unless noted otherwise in the scenario description, all scenarios use the updated narrower econ-demo uncertainty distribution, default Simultaneous Import Limits, thermal ambient output derating, and include scheduled maintenance.

Monthly PRM values use current capacity value counting conventions (i.e., not UCAP).

PRM Calibration Tool – Background and Corrections Identified

Background – Description of PRM Calibration Tool

What It Does:

The PRM Calibration Tool helps translate LOLE studies into PRM requirements. It performs the following functions:

- Determines the monthly Planning Reserve Margins (PRM) based on a set of inputs:
 - Resources and capacities (alternately NQC or UCAP) loaded in SERVIM
 - Slice-of-Day profiles for each resource types
 - Slice-of-Day Managed Load Forecast
 - Negative Operating Unit (NOUs)
- PRM is the margin over managed load at which storage is fully utilized
 - Excess non-storage capacity is used to charge storage
 - Storage must not drop below 0% state-of-charge
 - Storage cannot exceed instantaneous capacity and daily energy physical limits

How It is Used:

- After changing any inputs, the solver must re-run to determine the correct PRM or recalculate NOU levels to yield desired PRM
- Results indicate the “most-constrained” hour each month, defined as the hour during which storage is deployed at its highest rate
- Zeros in the excess charging energy, daily storage energy, or minimum state-of-charge columns of the PRM Setting worksheet indicate which constraint is reached
- Staff use the PRM Calibration Tool alongside SERVIM to determine NOU values and PRMs that deliver 0.1 LOLE

PRM Calibration Tool Updates and Error Correction

Staff made several changes and corrections that were included in the Aug. 14th Publication:

- Storage SOC Day 2
 - Updated formula & scripts to correctly apply Day 1 HE 24 as SOC for Day 2 HE 1
 - Update does not affect resulting PRM values
- Added UCAP values in applicable versions of the workbook
 - PRM Calibration Tool applies individual or resource-group EFORd & ambient temp. derate to determine each resource's capacity value
 - In SERVVM, analogous outage rates and deration rates due to ambient temperatures based on CAISO data for each unit are incorporated into the model

Since August 14, staff identified an error in the PRM Calibration Tool related to generation profiles for wind and solar resources

- Staff corrected solar and wind profiles in the PRM tool after parties identified the mistake. Staff reran the PRM Calibration Tool, reassessed PRM values in peak and off-peak months, and reran SERVVM to perform stress tests again.
- **The main effect was to lower PRM values in peak months by about 4%** but also force a rerun of stress tests for off-peak months.

Impact of profile correction – comparison of August 14 results with September 15 results

Corrected Stress Test Results				Previous Stress Test Results			
Month	Demand Added (MW)	PRM	LOLE	Demand Added (MW)	PRM	LOLE	Diff in PRM
1	15,158	19.00%	0.0	16,333	21.7%	0.0	-2.70%
2	17,832	19.00%	0.0	18,969	21.7%	0.0	-2.70%
3	18,640	19.00%	0.0	17,659	21.8%	0.0	-2.80%
4	19,784	19.00%	0.0	18,784	21.8%	0.0	-2.80%
5	19,812	21.00%	0.0039	19,301	21.9%	0.0039	-0.90%
6	10,577	21.00%	0.0009	9,133	21.9%	0.0	-0.90%
7	6,891	21.00%	0.0367	5,642	25.2%	0.0018	-4.20%
8	6,518	21.00%	0.0525	6,665	25.1%	0.0640	-4.10%
9	4,430	21.00%	0.0042	5,008	25.2%	0.0185	-4.20%
10	12,669	19.00%	0.0	14,957	25.1%	0.0201	-6.10%
11	15,050	19.00%	0.0	19,284	21.8%	0.0	-2.80%
12	14,098	19.00%	0.0	17,944	21.9%	0.0	-2.90%
Total			0.0981			0.1083	

- **Summer PRM reduced by about 4%** after correcting renewable profiles
- Less LOLE in off-peak months. October results are now more like previous modeling performed in 2024 and in IRP

Annual LOLE Studies – Key Inputs

Base Case Inputs

- **SERVM database updated as described in I&A document**
 - Weather and hydro profiles updated to cover 2000-2024 (25 weather years vs. 23 weather years in 2024)
 - 2025 IEPR Planning scenario without Known loads
 - Non-CA demand forecast updated
 - 2026 updated Baseline resources for CAISO and WECC 2034 Anchor Data Set units
 - Includes DCPD and Sunzia
 - Numerous updates to operational variables, maintenance rates, and forced outage rates
 - Thermal ambient output derating included and updated
 - DCPD refueling schedule included
 - Outside regions were not tuned towards 0.1 LOLE
- **CAISO Simultaneous Import Limits**
 - **Base Case**
 - 11,040 MW upper limit in SERV (representing Maximum Import Capability), plus a tighter 4,000 MW limit in hours 17-22 during June – Sept, with 3-hour ramp transition between limits
 - In the SOD PRM Tool “monthly interchange” input, 8,500 MW was used for non-summer months and 4,000 MW was used for summer months. 8,500 MW represents the actual maximum import level used to maintain CAISO reliability in the SERV simulation for non-summer months (meaning the 11,040 MW upper limit never binds). Staff decided the actual imports used in the SERV simulation more realistically represents the interchange value for calculating the PRM in the SOD PRM Tool.
 - **Sensitivity**
 - Tighten all limits to zero, i.e. no imports in all hours

Study Setup

As discussed in 2026 I&A document, staff setup the 2028 LOLE study as follows:

- 25 weather years from 2000 to 2024 combined with same Hydro Years
 - "Weather-Hydro Cases" this cycle is 25
 - Last cycle it was 23 weather cases X 23 hydro cases = 529 Cases. It was assumed that weather and hydro conditions were relatively independent of each other and each combination varied enough to increase the range of conditions studied.
- Iterations (random outage draws) increased for better results convergence for each case
 - This "trade-off" reduces weather-hydro combinations for more random outage combinations
 - For initial results shown in the August 14 draft report, staff ran studies with 15 or 30 iterations to speed up run time
 - For this presentation, all studies were run at 30 iterations per case
 - For the final October report, staff intend to confirm final results with studies run at 50 iterations per case
- **5 points of economic and demographic uncertainty (EDU), updated to align with probability distribution derived from a MISO reliability study***
 - New distribution has higher probability of 0 load forecast error and lower probability of errors at higher and lower tails
 - Sensitivity with prior distribution was conducted to isolate impact

CPUC Prior Economic and Demographic Uncertainty Probabilities		Updated Economic and Demographic Uncertainty Probabilities Adopted from MISO 2025-2026 LOLE Study	
Load forecast error	Probability	Load forecast error	Probability
2.5%	0.0668	2.0%	0.0090
1.5%	0.2417	1.0%	0.2050
0%	0.3829	0.0%	0.5730
-1.5%	0.2417	-1.0%	0.2050
-2.5%	0.0668	-2.0%	0.0090

* MISO 2025-2026 LOLE Study Report: <https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401>

Key changes relative to 2026 RA LOLE study conducted in 2024

Current RA LOLE studies	Prior RA LOLE studies (conducted in 2024)	Likely reliability change
Updated SERVIM client (version 10) – uses storage more optimally and improves contribution to reliability	Older SERVIM client (version 9)	Improves
Updated Baseline Resources: - Added newly online units, corrected tech categories, retirements - August 2025 CAISO data, WECC 2034 ADS	2024 vintage of CAISO Baseline Resources	Improves
CEC 2025 IEPR California Energy Demand Forecast (2025-2045) – SERVIM consumption peak calibrated to match IEPR	CEC 2023 IEPR – SERVIM managed peak calibrated to match IEPR	See next slide
Historical Weather and Hydro range updated: 2000 – 2024 (25 years)	Historical range 2000 – 2022 (23 years)	Uncertain
Updated hourly BTMPV model calibrated with CEC model	Older BTMPV model with higher capacity factor	Uncertain
Added ambient temperature output derating to gas-fired and geothermal units	No ambient temperature output derating	Worsens
Updated scheduled maintenance rates and forced outage parameters based on unit-specific CAISO Outage Management System (OMS) data	Derived from older CAISO OMS data and some NERC GADS data using different methods to aggregate to technology/seasonal averages	See sensitivity results slide
Allow 20% of scheduled maintenance to be optimized according to specific weather year being simulated	Scheduled maintenance optimized according to peak daily demand across all weather year net load shapes	Improves
Updated various operating parameters/constraints (heat rates, start costs/fuel, ramp rates, min up/down times, max output, etc.)	Older data derived from the CAISO Masterfile and WECC Anchor Dataset 2032. Unclear if in sum the older operating parameters would improve or worsen reliability.	Uncertain
Used updated narrower Economic and Demographic Uncertainty distribution	Older (wider) Economic and Demographic Uncertainty distribution	Improves

Comparison of Baseline and Demand Changes since IRP MTR Need Determination studies* conducted in Sept 2025

CAISO Installed Capacity (MW)	RA LOLE	MTR Need	Diff
	SERVM	SERVM	
Unit Category	2028	2028	
Battery_4h	24,770	21,706	3,064
Biomass	753	626	127
BTMPV	21,302	22,638	(1,337)
CC/CT/ICE/Steam	24,542	25,417	(875)
Coal	-	-	-
Cogen	3,488	1,723	1,765
DR	1,866	1,878	(12)
Geothermal	1,739	2,030	(291)
Hydro	5,862	5,451	411
Hydro_RoR	238	211	27
Hydro_NW_CAISO	1,647	1,507	140
Nuclear	2,935	635	2,300
OffshoreWind	-	-	-
OOSWind	3,982	3,621	361
PSH	1,487	1,643	(156)
Solar	28,988	28,357	631
Wind	7,293	6,605	688
Total of all Solar/Wind incl. BTMPV	61,565	61,222	343
Total Gas	28,030	27,140	890
Total Gas+Bio+Geo+Nuke+Stor	59,714	53,780	5,934

	Managed Peak MW	Managed Energy GWh
2024 IEPR	49,451	245,769
2025 IEPR	48,356	227,284
Diff	(1,095)	(18,485)

- 1 GW lower managed peak
- 18 TWh less managed annual energy
- ~6 GW more effective capacity
 - Inclusion of DCPD
 - New storage
 - No capping to monthly NQC values
 - New wind/solar offset by less BTMPV
- Expect a surplus of 6-7 GW PCAP
 - Confounded by numerous operating variable updates and Case buildup/econ-demo uncertainty changes
 - The MTR Need 2028 study was not tuned to 0.1 LOLE (it was 0.04 LOLE) so the surplus could be bigger than estimated above

* The IRP Mid Term Reliability (MTR) Need Determination studies covered 2028-2032 and we are comparing the 2028 study from that work to the RA 2028 study here.

Annual LOLE Studies – Methods of Calibrating LOLE

Description of LOLE Calibration

- Staff needed to calibrate the CAISO system to a target of 0.1 LOLE annually. Staff proposed to calibrate using added demand blocks. SCE proposed instead proportionately derating capacity. No perfect capacity was added as the CAISO system showed a surplus.
- Staff tested three methods for surfacing LOLE:
 - Adding demand blocks – flat load added for whole year
 - Prorating capacity – reduced Pmax of each technology category of generating/storage unit by the same percentage for the whole year
 - Simultaneous import limits were also prorated but hydro units were not prorated. Staff adopted these assumptions to be consistent with and comparable to what SCE did in their prorating capacity study.
 - Tightening simultaneous import limits toward zero

Annual LOLE Studies – Results

Adding Demand Blocks

Base Case (no tuning) vs. Base Case (Flat Load) 6,000 MW added: reliability, annual energy balance, and GHG emissions

	Base case as found, untuned	Base case, with 6 GW flat load added	
Annual Energy Balance			
Category	2028	2028	Units
Battery_4h	(4,417)	(4,562)	GWh
Battery_8h	-	-	GWh
LDES	-	-	GWh
Biomass	3,488	3,784	GWh
BTMPV	33,386	33,386	GWh
Gas	40,554	71,765	GWh
Coal	-	-	GWh
DR	0	1	GWh
Geothermal	12,491	13,377	GWh
Total Hydro	32,611	32,612	GWh
Nuclear	23,806	23,806	GWh
OffshoreWind	-	-	GWh
OOSWind	15,837	15,837	GWh
PSH	(617)	(597)	GWh
Solar	77,937	77,938	GWh
Wind	17,334	17,334	GWh
Curtailed Energy	(3,849)	(1,029)	GWh
Gross Imports	16,717	31,333	GWh
Gross Exports	(3,934)	(1,081)	GWh
Total Load (After Modifiers)	261,260	261,260	GWh
Total Supply	261,344	261,343	GWh

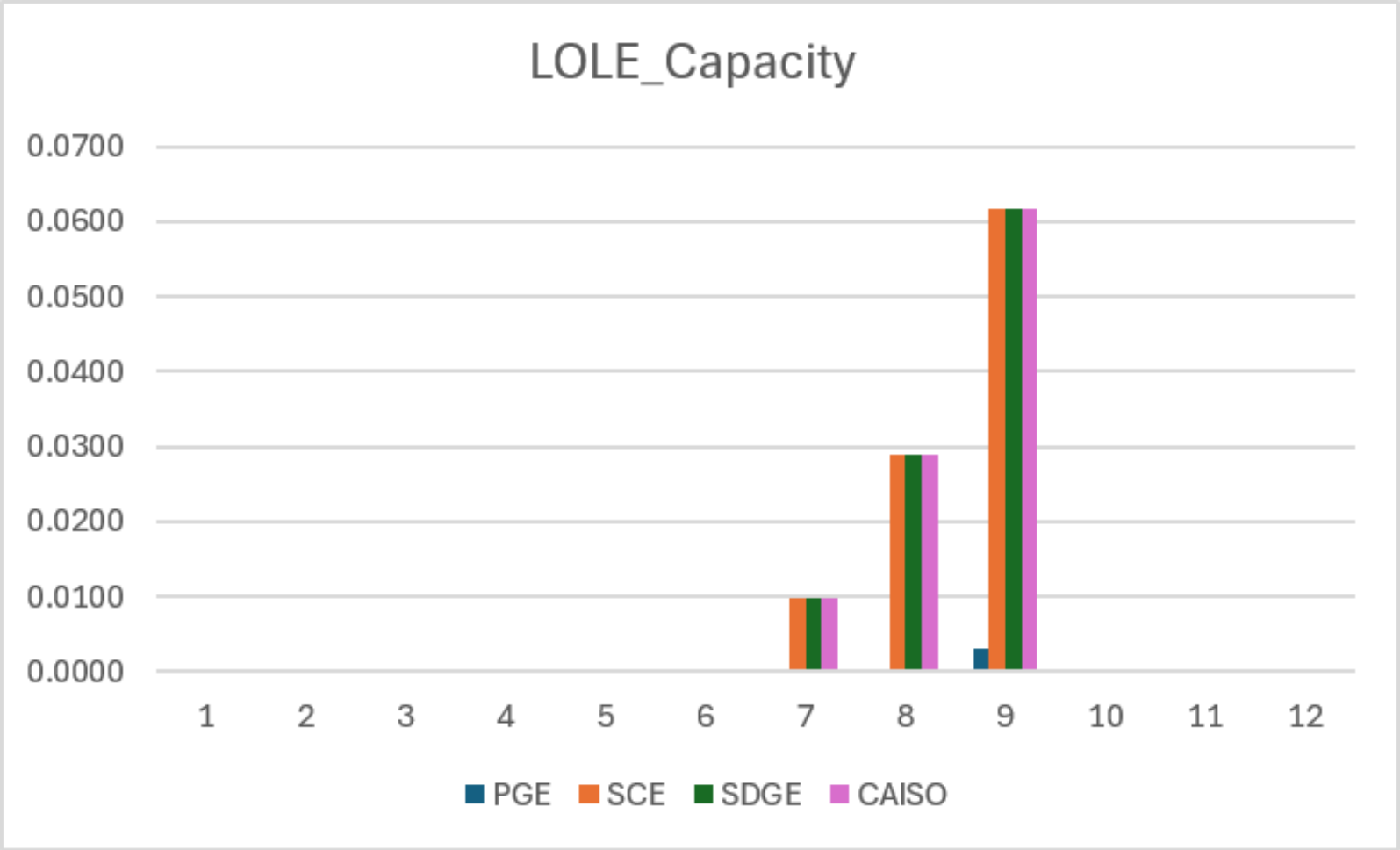
	Base case as found, untuned	Base case, with 6 GW flat load added	
Annual GHG Emissions			
Category	2028	2028	Units
CAISO emitting generation	40,554	71,765	GWh
CAISO Generator Emissions	17.29	29.86	MMT CO2
Imports (unspecified)	16,717	31,333	GWh
Unspecified emissions	7.16	13.41	MMT CO2
CAISO BTM CHP Emissions	-	-	MMT CO2
Total CAISO Emissions	24.45	43.27	MMT CO2
Annual Reliability Metrics			
Metric	2028	2028	Units
LOLE Capacity	-	0.100	days/year
EUE	-	483.5	MWh
LOLH Capacity	-	0.196	hours/year
LOLH/LOLE (average length of outage)	-	1.960	hours/day

- Base case with no tuning is over reliable given surplus supply in the Baseline relative to other recent studies of 2028
- About 6 GW of additional flat load to achieve 0.1 LOLE
- In the tuned study, the extra load soaks up curtailment and gas/unspecified imports meets the rest of the extra load, raising GHG emissions. Note the tuned system is not a real system so CAISO emissions are not expected to be that high.

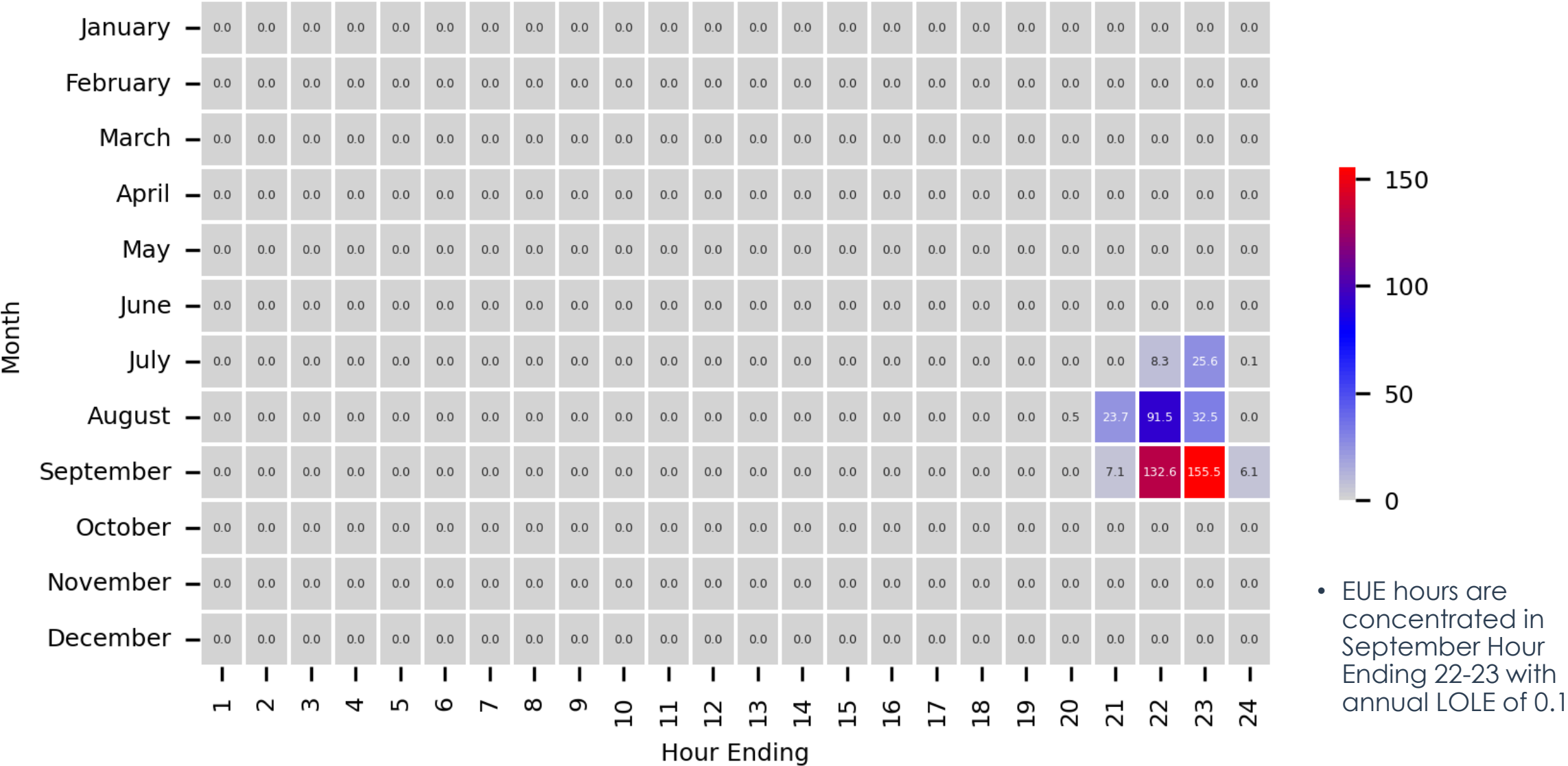
Base Case (Flat Load), Monthly LOLE Capacity

Annual Reliability Metrics		
Metric	2028	Units
LOLE Capacity	0.100	days/year
EUE	483.5	MWh
LOLH Capacity	0.196	hours/year
LOLH/LOLE (average length of outage)	1.960	hours/day

- In flat load tuning scenario, SCE and SDGE contribute equally to CAISO LOLE
- PGE is much more reliable than SCE and SDGE



Base Case (Flat Load), EUE Heatmap



Base Case (Flat Load), translated into monthly PRM

- 6,000 MW of flat load was added to tune LOLE to 0.1
- September shows the lowest annual PRM of 16.64%
- July, August and September show unserved energy with a sum of 0.1002 LOLE

Month	NOU	PRM	LOLE	Constraining Hour
1	6,000	53.32%	0.0	19
2	6,000	63.59%	0.0	19
3	6,000	66.13%	0.0	19
4	6,000	68.64%	0.0	19
5	6,000	70.93%	0.0	20
6	6,000	34.49%	0.0	20
7	6,000	23.49%	0.0097	19
8	6,000	22.47%	0.0288	19
9	6,000	16.64%	0.0617	18
10	6,000	40.56%	0.0	18
11	6,000	52.04%	0.0	18
12	6,000	48.42%	0.0	18
Total			0.1002	

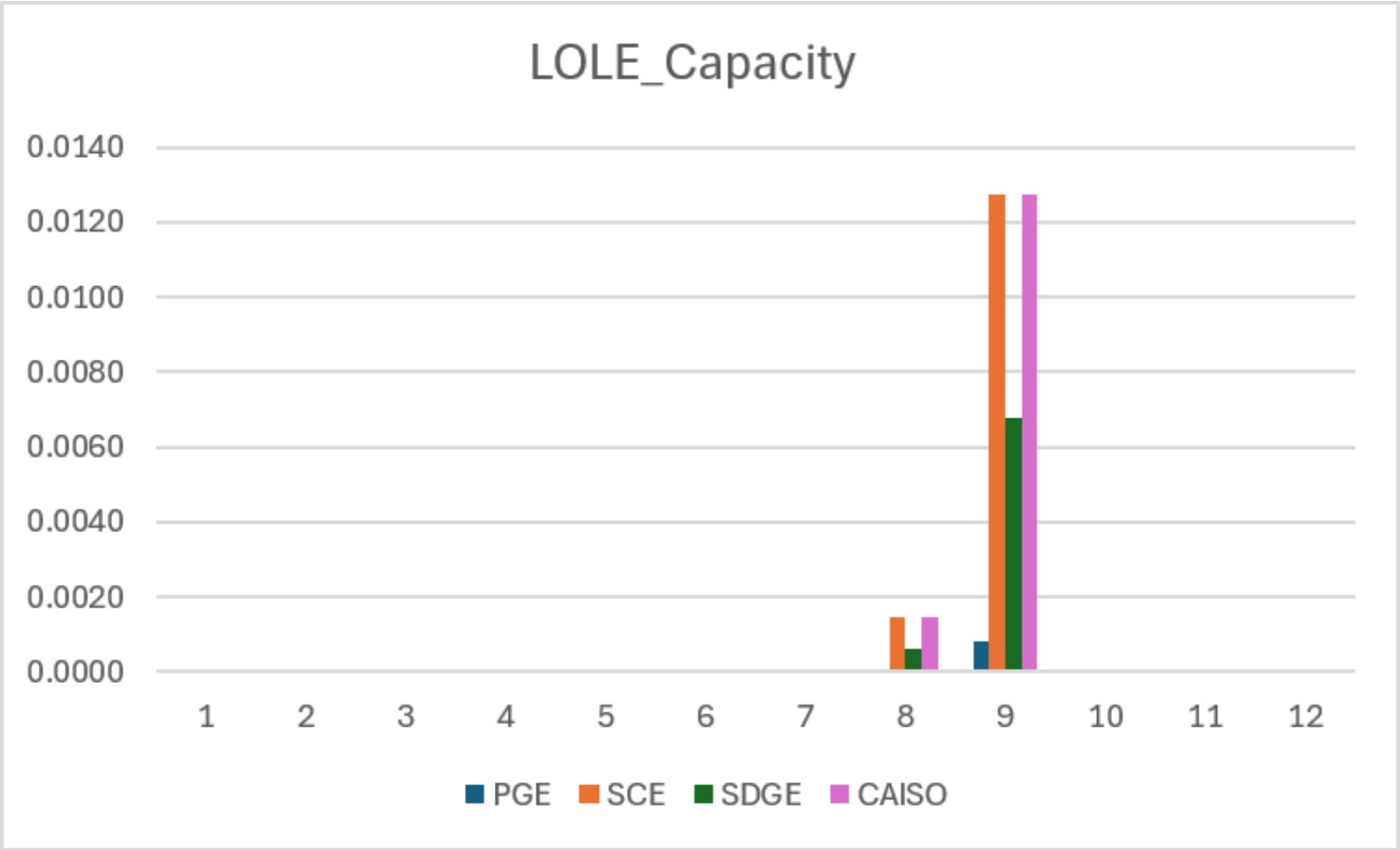
Annual LOLE – Results

Tightening Imports

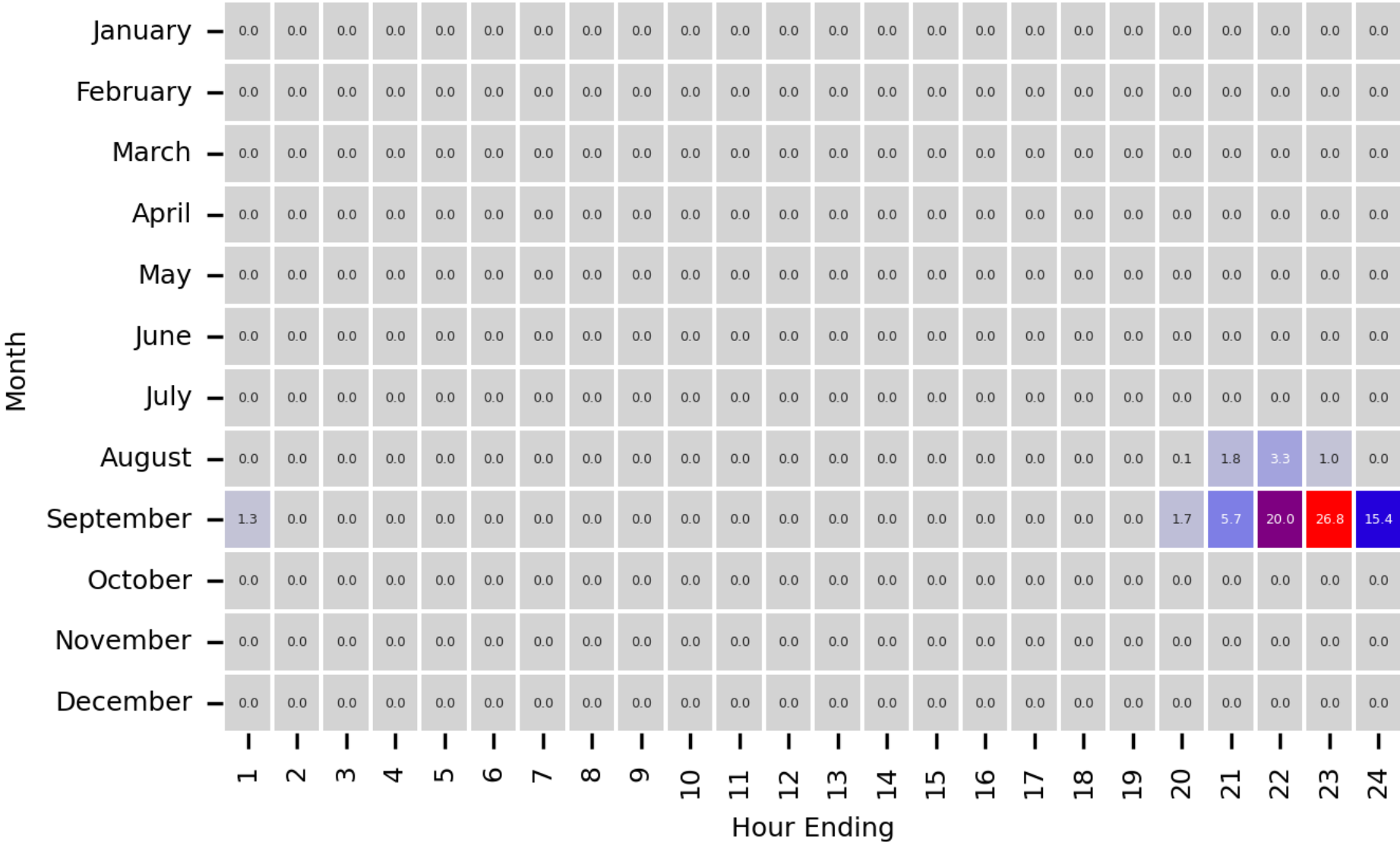
Base Case (Constrain Imports), Monthly LOLE Capacity

Annual Reliability Metrics		
Metric	2028	Units
LOLE Capacity	0.014	days/year
EUE	77.0	MWh
LOLH Capacity	0.033	hours/year
LOLH/LOLE (average length of outage)	2.303	hours/day

- The CAISO system is longer than 4 GW since this scenario constrained imports all the way to zero and is still somewhat over reliable.
- Relative to the Base Case tuned with flat load, SCE is now the region driving LOLE. This is consistent with SCE relying on direct imports more significantly than SDGE.



Base Case (Constrain Imports), EUE Heatmap



- 25
20
15
10
5
0
- EUE hours are still concentrated in September Hour Ending 22-23 with annual LOLE of 0.014

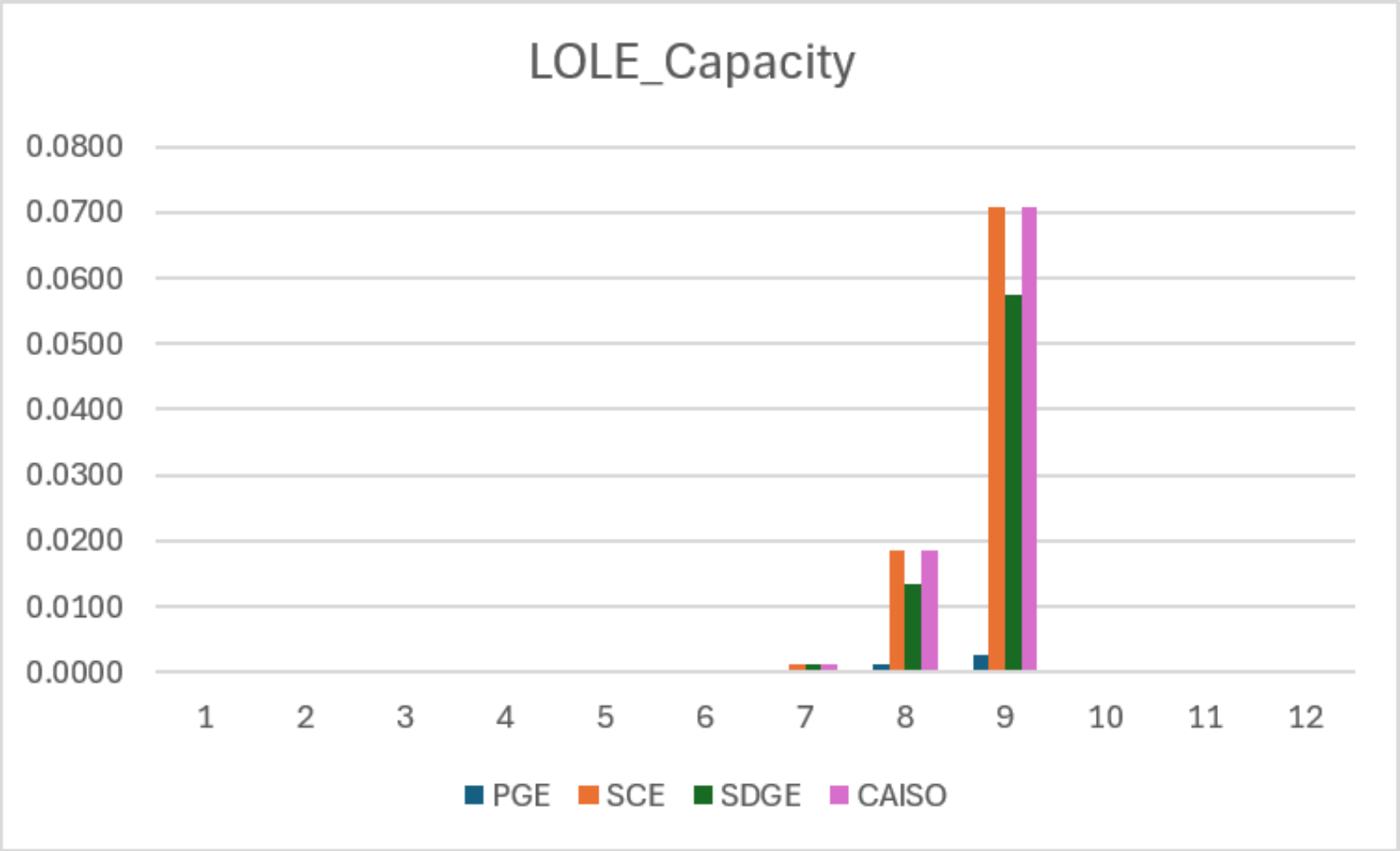
Annual LOLE – Results

Prorating Capacity

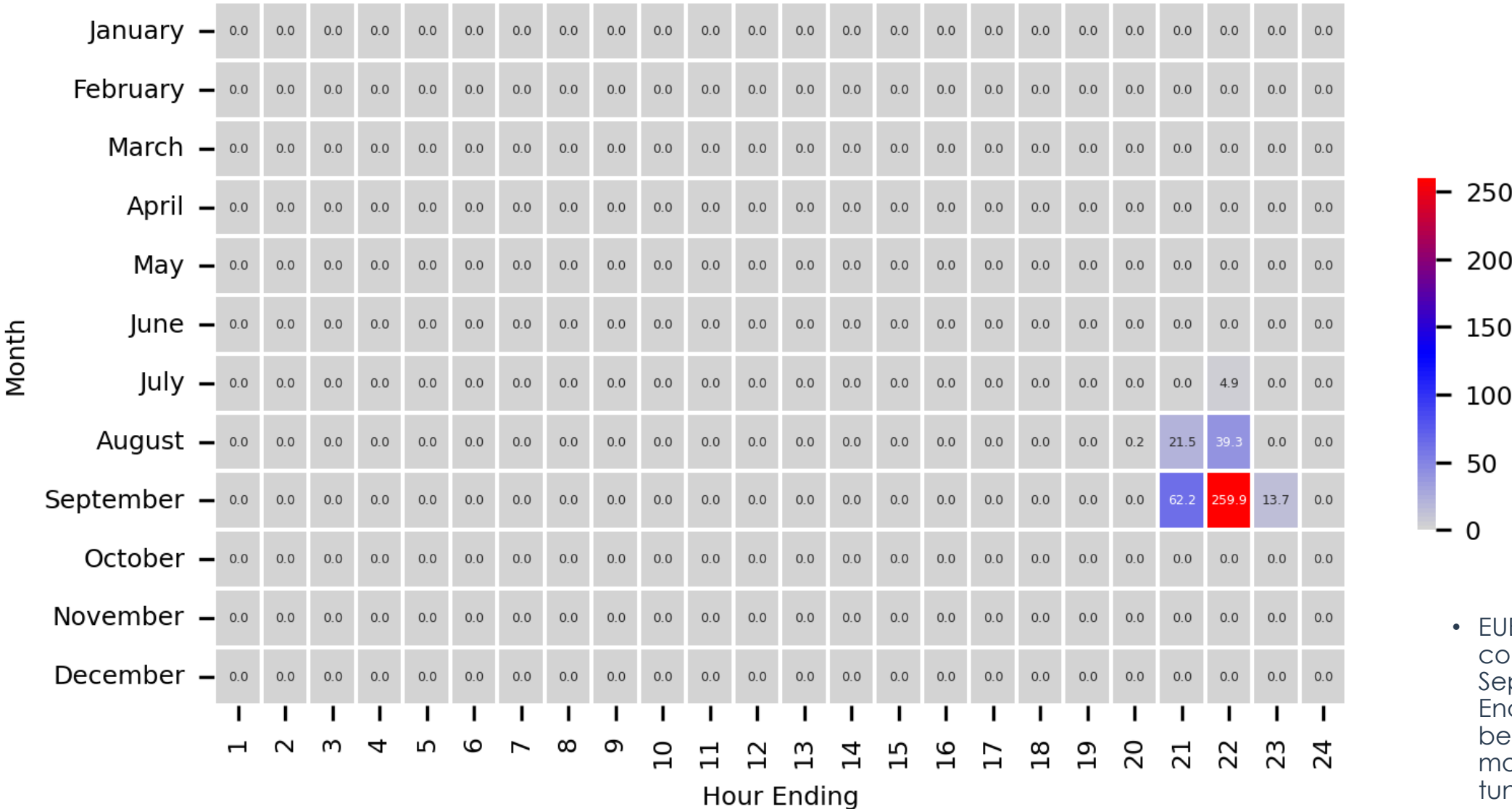
Base Case (Prorate Capacity) 95%, Monthly LOLE Capacity

Annual Reliability Metrics		
Metric	2028	Units
LOLE Capacity	0.091	days/year
EUE	401.7	MWh
LOLH Capacity	0.143	hours/year
LOLH/LOLE (average length of outage)	1.574	hours/day

- This scenario prorated all generation and storage capacity including simultaneous import limits but did not prorate hydro capacity
- 95% prorating equates to removing about 5.5 GW from the Baseline resources installed capacity and 200 MW from the peak hour/month simultaneous import limit of 4 GW
- No Economic Demographic Uncertainty was included meaning uncertainty was due to weather and random forced outage draws only. These assumptions were chosen to align with SCE's prorate capacity study



Base Case (Prorate Capacity) 95%, EUE Heatmap



- EUE hours are more concentrated in September Hour Ending 22 relative to being spread out a bit more in the scenario tuned with flat load

Comparing no tuning, adding 6 GW flat load, and prorating capacity 95%: reliability, annual energy balance, GHG emissions

	Base case as found, untuned	Base case, with 6 GW flat load added	Base case, with 95% capacity prorate	
Annual Energy Balance Category	2028	2028	2028	Units
Battery_4h	(4,417)	(4,562)	(2,683)	GWh
Battery_8h	-	-	-	GWh
LDES	-	-	-	GWh
Biomass	3,488	3,784	3,329	GWh
BTMPV	33,386	33,386	33,386	GWh
Gas	40,554	71,765	48,028	GWh
Coal	-	-	-	GWh
DR	0	1	1	GWh
Geothermal	12,491	13,377	12,136	GWh
Total Hydro	32,611	32,612	32,596	GWh
Nuclear	23,806	23,806	22,616	GWh
OffshoreWind	-	-	-	GWh
OOSWind	15,837	15,837	15,046	GWh
PSH	(617)	(597)	(1,044)	GWh
Solar	77,937	77,938	74,000	GWh
Wind	17,334	17,334	16,470	GWh
Curtailed Energy	(3,849)	(1,029)	(6,796)	GWh
Gross Imports	16,717	31,333	19,875	GWh
Gross Exports	(3,934)	(1,081)	(5,611)	GWh
Total Load (After Modifiers)	261,260	261,260	261,260	GWh
Total Supply	261,344	261,343	261,348	GWh

	Base case as found, untuned	Base case, with 6 GW flat load added	Base case, with 95% capacity prorate	
Annual GHG Emissions Category	2028	2028	2028	Units
CAISO emitting generation	40,554	71,765	48,028	GWh
CAISO Generator Emissions	17.29	29.86	20.36	MMT CO2
Imports (unspecified)	16,717	31,333	19,875	GWh
Unspecified emissions	7.16	13.41	8.51	MMT CO2
CAISO BTM CHP Emissions	-	-	-	MMT CO2
Total CAISO Emissions	24.45	43.27	28.87	MMT CO2
Annual Reliability Metrics				
Metric	2028	2028	2028	Units
LOLE Capacity	-	0.100	0.091	days/year
EUE	-	483.5	401.7	MWh
LOLH Capacity	-	0.196	0.143	hours/year
LOLH/LOLE (average length of outage)	-	1.960	1.574	hours/day

- The prorate scenario shows increased curtailment due to less batteries in the system. Generally non-dispatchable generation total energy is reduced by 5% as expected (Geothermal, Nuclear, Wind, Solar).

Comparing no tuning, adding 6 GW flat load, and prorating capacity 95%: translation to annual PRM

Month	Base Case, as Found	Base Case (Flat Load)	Base Case (Prorate Capacity)
1	88.98%	53.32%	79.71%
2	101.30%	63.59%	91.42%
3	104.10%	66.13%	94.13%
4	105.49%	68.64%	95.52%
5	108.17%	70.93%	98.11%
6	56.06%	34.49%	48.52%
7	43.37%	23.49%	36.51%
8	42.51%	22.47%	35.66%
9	34.66%	16.64%	28.13%
10	67.22%	40.56%	58.92%
11	86.28%	52.04%	77.05%
12	81.67%	48.42%	72.76%

- Base Case as Found is not calibrated to 0.1 LOLE so achieved PRM is not comparable to other two calibrated scenarios
- Base Case (Flat Load) and Base Case (Prorate Capacity) both tuned to 0.1 but observed PRM differs between methodologies

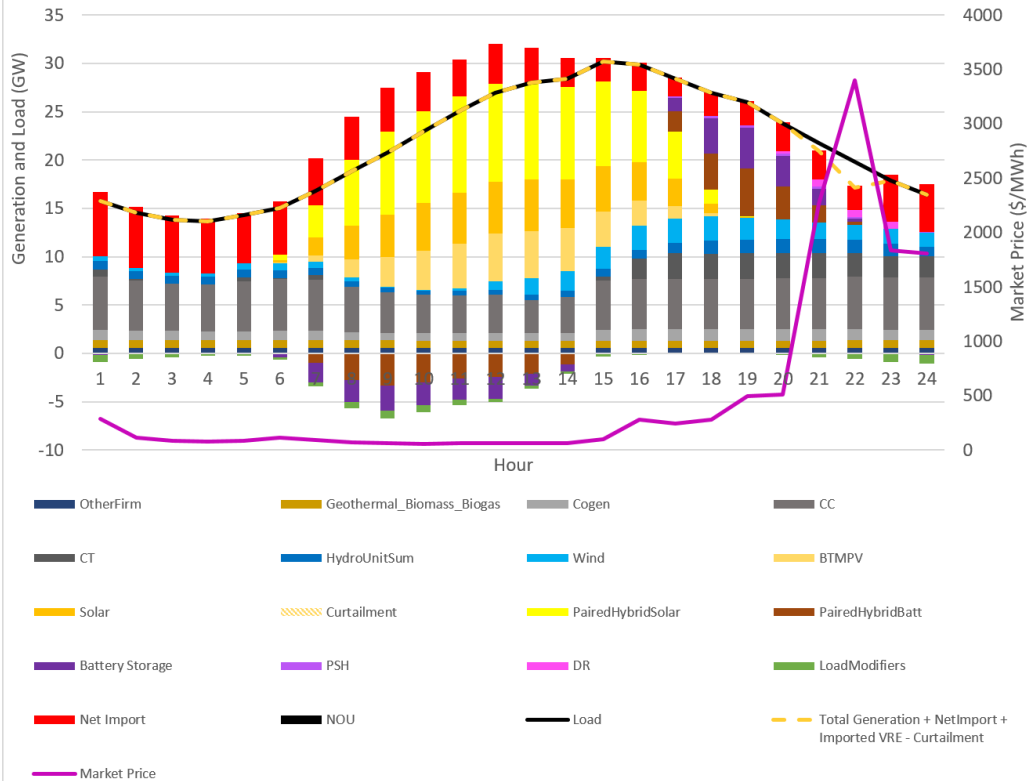
Comparison of Dispatch Charts between Prorate Capacity and Demand Added Calibration

Prorate

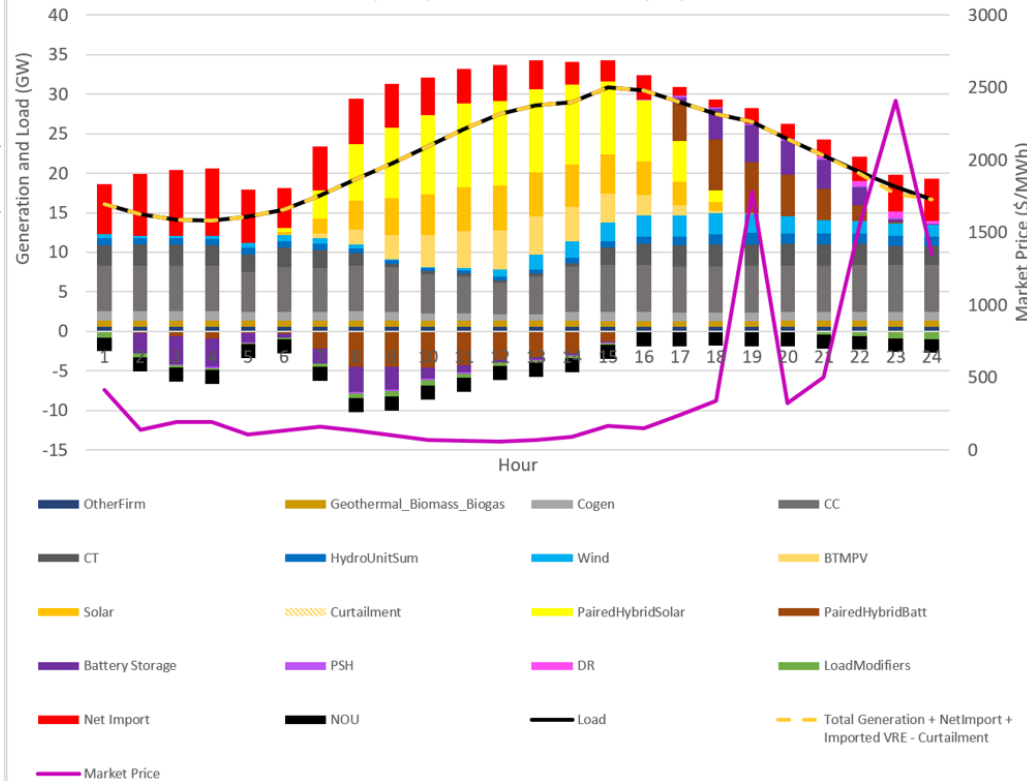
Demand Added

- Prorate scenario appears to use less energy and consume less SOC
- EUE starts one hour earlier and ends one hour earlier in prorate scenario.
- SOC goes up to about 80% in Demand Added scenario, but to 94% in Prorate Scenario
- Both cases are representing Weather/Hydro year 2022

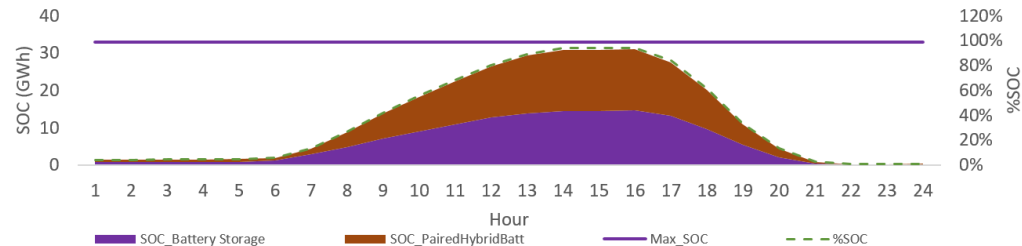
SCE Dispatch, Load and Prices on Sep. 5, 2028



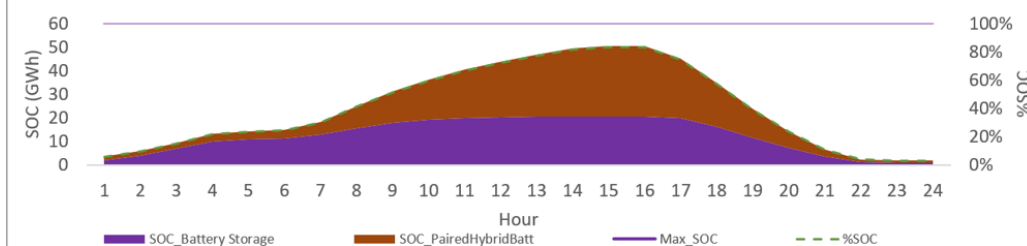
SCE Dispatch, Load and Prices on Sep. 5, 2028



SOC of Batteries



SOC of Batteries



Monthly Stress Tests – Methodology

Monthly Stress Test Methodology

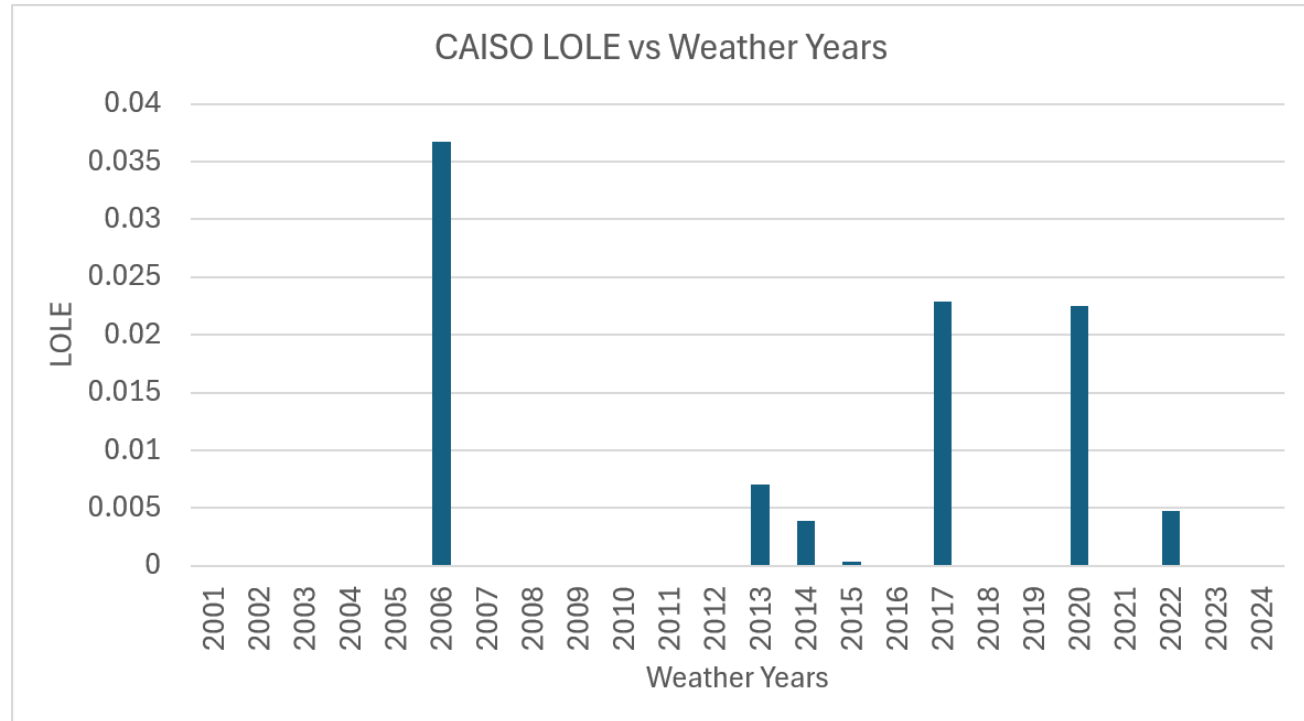
- Annual LOLE studies provide a PRM based on most constraining hour during summer months of 2028
- After performing annual LOLE study, staff performed monthly stress test studies to determine lower PRM levels for non-summer months
- For this purpose, varying blocks of demand were added to non-summer months to surface LOLE in these months while keeping total annual LOLE at 0.1
- Staff implemented monthly stress tests only for scenarios with added demand, not for Prorate Capacity scenario

Monthly Stress Tests – Results

Monthly Stress Test Results for 2028 RA Study – New Results

With Thermal Derates
No Maintenance

Month	Demand Added	PRM	LOLE
1	15,158	19.00%	0.0
2	17,832	19.00%	0.0
3	18,640	19.00%	0.0
4	19,784	19.00%	0.0
5	19,812	21.00%	0.0039
6	10,577	21.00%	0.0009
7	6,891	21.00%	0.0367
8	6,518	21.00%	0.0525
9	4,430	21.00%	0.0042
10	12,669	19.00%	0.0
11	15,050	19.00%	0.0
12	14,098	19.00%	0.0
Total			0.0981



- Stress Test results indicate a 21% PRM in May-Sep and 19% PRM in other months are required to maintain a LOLE of 0.1
- 2006, 2017 and 2020 weather years seem to have the most impact on LOLE

Unadjusted PRM and UCAP PRM Comparison – Base Case (Flat Load) and Base Case (Stress Test) Scenarios

- Applying UCAP resource accreditation in PRM Tool decreases the PRM between 4.68 and 7.7 percentage points in flat load scenario
- For monthly stress test, UCAP PRM decreases between 4.6 and 5.46 percentage points

	Base Case (Flat Load)			Base Case (Stress Test)		
Month	Unadjusted PRM	UCAP PRM	Diff. Percentage Points	Unadjusted PRM	UCAP PRM	Diff. Percentage Points
1	53.32%	46.74%	-6.58%	19.01%	13.90%	-5.11%
2	63.59%	55.91%	-7.67%	19.03%	13.73%	-5.30%
3	66.13%	58.43%	-7.70%	19.03%	13.60%	-5.43%
4	68.64%	61.10%	-7.54%	19.04%	13.72%	-5.32%
5	70.93%	63.51%	-7.42%	21.05%	15.79%	-5.26%
6	34.49%	28.61%	-5.88%	21.00%	15.54%	-5.46%
7	23.49%	18.80%	-4.69%	21.00%	16.40%	-4.60%
8	22.47%	17.70%	-4.78%	21.00%	16.28%	-4.72%
9	16.64%	11.95%	-4.68%	21.00%	16.14%	-4.86%
10	40.56%	35.03%	-5.53%	19.00%	14.32%	-4.69%
11	52.04%	45.67%	-6.37%	19.01%	14.02%	-4.99%
12	48.42%	42.04%	-6.38%	19.01%	13.89%	-5.12%

Updated Results 9-15-2026. UCAP PRM includes EFORD & Ambient derates.

Sensitivities to test impact of input updates since 2024 LOLE study

Sensitivities to test PRM Impacts driven by Changes to Data and Methods

	PRM Result	PRM Impacts
2026 LOLE Study *	21%	
2028 LOLE Study	21%	
Thermal Derate effect		+2%
Updated Forced Outage Rates		-1%
Updated Econ-Demo Uncertainty		-0.6%
Total Net Changes		+0.4%

* 2026 results reflect updated PRM values published in Feb. 2025 RA workshop. See [2-25-2026 R.25-10-011 Ruling](#).

- Our updated results after correction of renewable profiles in the SOD Tool, shows lower PRM levels than what was shown in the August report.
- Our three sensitivities show how current study results compare to the 2024 study conducted for RA Year 2026:
 - Adding thermal derates increased the PRM by about 2 percentage points
 - Updating forced outage rates resulted in lowering the PRM by about 1 percentage point
 - Updating econ-demo uncertainty lowered the PRM about 0.6 percentage points
- **Net result is minimal change to PRM due to the above factors**

Sensitivities to Test Input Update Impact

Forced Outage Rates Update

Updated Forced Outage Rates Impact on PRM

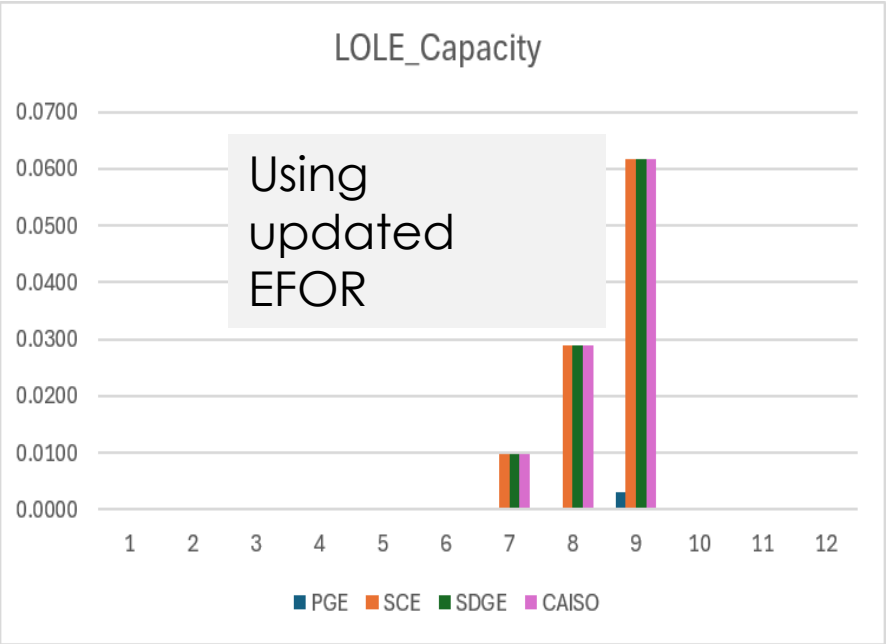
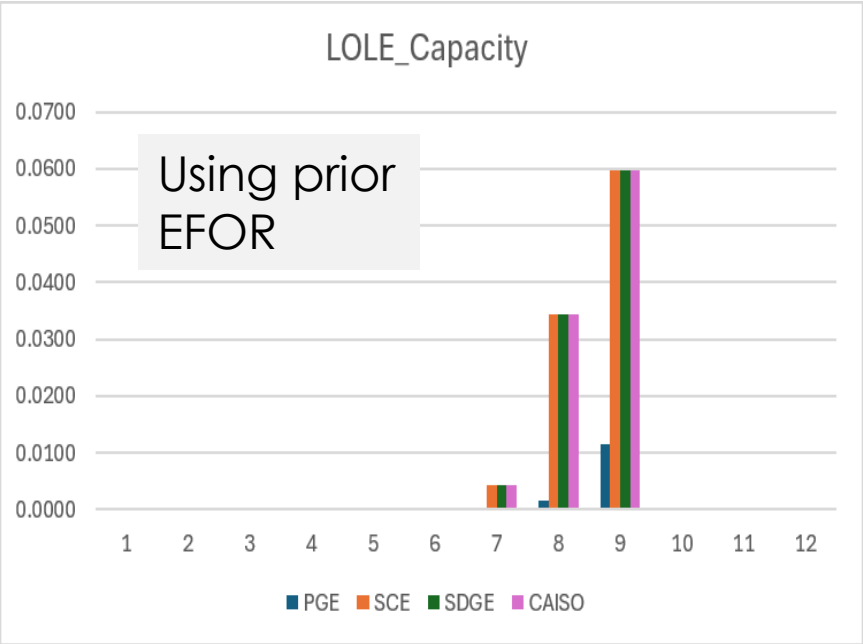
	Base case, with prior EFOR and 5.6 GW flat load added	Base case, with updated EFOR and 6 GW flat load added
Region	System EFOR (%)	System EFOR (%)
CAISO	2.40	2.01
Unit Category	EFOR (%)	EFOR (%)
Battery_4h	3.50	4.44
Biogas	1.09	0.52
CC	7.24	5.64
CT	20.69	7.49
Cogen	10.10	10.57
Geothermal	0.91	5.95
Hybrid_BattStorage	3.13	3.32
ICE	3.07	3.21
PSH	0.70	4.25
Paired_BattStorage	3.64	3.08

- Switching from GADS data to CAISO Curtailment data allowed about 400 MW more flat load to be added to the system to achieve the same reliability level. **In summer months, this equated to about a one percentage point reduction in reserve margin.**

	Base Case (Prior Forced Outage Rates)			Base Case (Flat Load)		
Month	Demand Added (MW)	PRM	LOLE	Demand Added (MW)	PRM	LOLE
1	5,600	55.28%	0.0	6,000	53.32%	0.0
2	5,600	65.67%	0.0	6,000	63.59%	0.0
3	5,600	68.23%	0.0	6,000	66.13%	0.0
4	5,600	70.71%	0.0	6,000	68.64%	0.0
5	5,600	73.00%	0.0	6,000	70.93%	0.0
6	5,600	35.78%	0.0	6,000	34.49%	0.0
7	5,600	24.64%	0.0043	6,000	23.49%	0.0097
8	5,600	23.64%	0.0344	6,000	22.47%	0.0288
9	5,600	17.72%	0.0596	6,000	16.64%	0.0617
10	5,600	42.10%	0.0	6,000	40.56%	0.0
11	5,600	53.93%	0.0	6,000	52.04%	0.0
12	5,600	50.25%	0.0	6,000	48.42%	0.0
Total			0.0983			0.1002

Tuned Base Case with prior EFOR vs. updated EFOR, Monthly LOLE Capacity

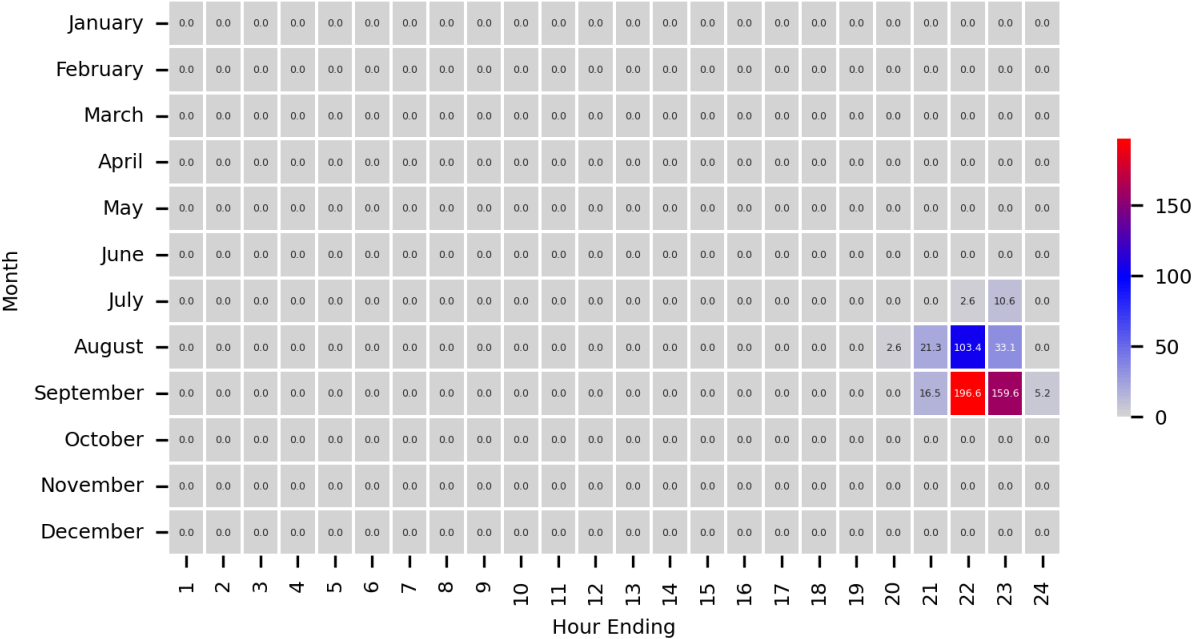
Annual Reliability Metrics	Base case, with prior EFOR and 5.6 GW flat load added	Base case, with updated EFOR and 6 GW flat load added	Units
	2028	2028	
LOLE Capacity	0.092	0.100	days/year
EUE	441.5	483.5	MWh
LOLH Capacity	0.183	0.196	hours/year
LOLH/LOLE (average length of outage)	1.977	1.960	hours/day



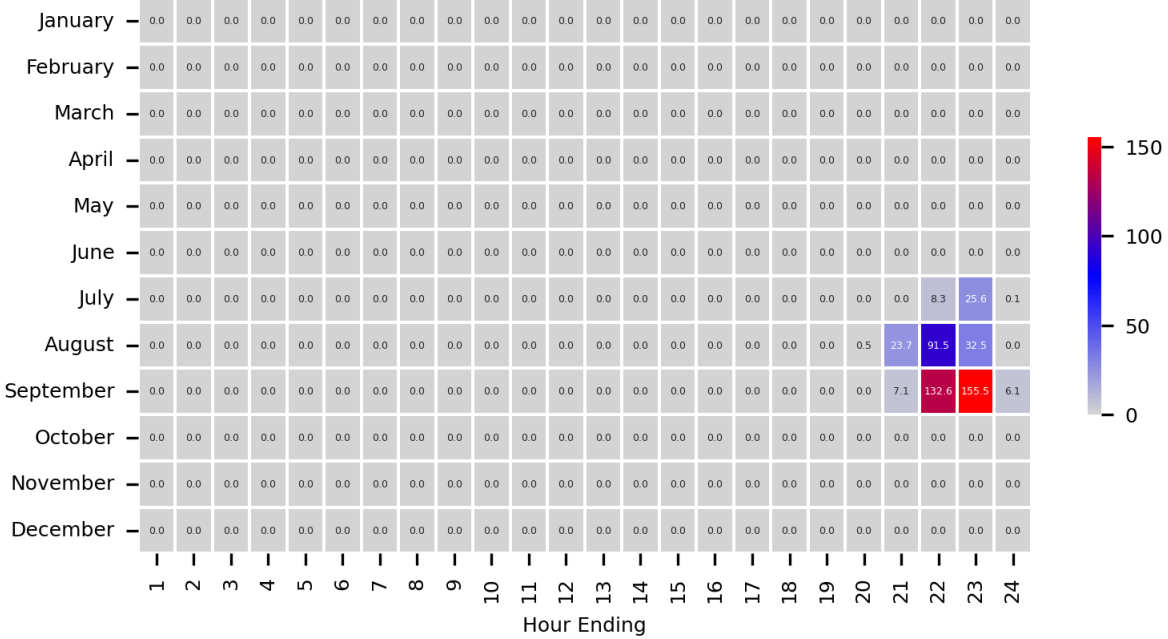
- LOLE is still concentrated in September in SCE & SDGE territory, but the new outage rates appear to produce less LOLE in PGE territory, and less LOLE overall in August.

Tuned Base Case with prior EFOR vs. updated EFOR, EUE Heatmap

Using prior EFOR



Using updated EFOR



Updated EFOR values overall reduce reliability risk, and show more even spread of LOLE across summer months, decreasing in September and increasing prevalence in July

Sensitivities to Test Input Update Impact

Econ Demo Uncertainty Distribution

Economic and Demographic Uncertainty Impact on PRM

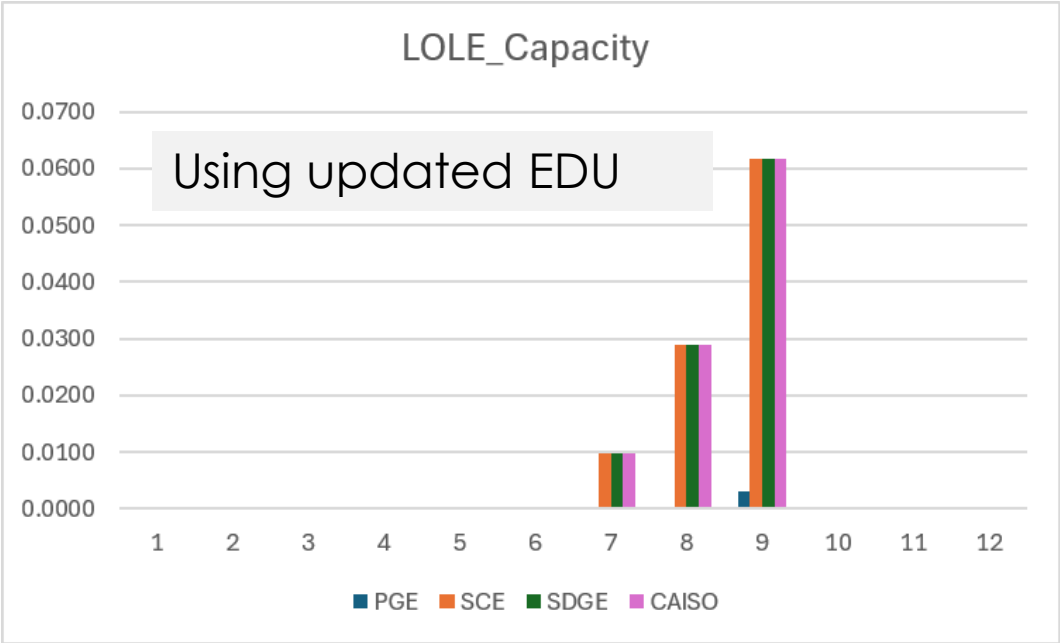
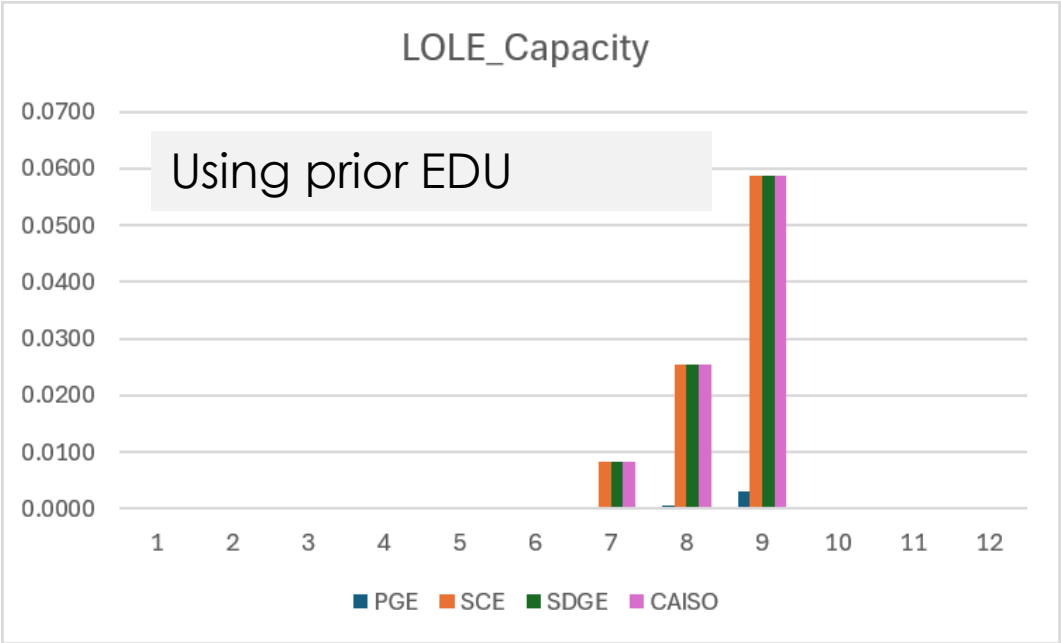
Prior Economic and Demographic Uncertainty Probability Distribution		Updated Economic and Demographic Uncertainty Probability Distribution	
Load forecast error	Probability	Load forecast error	Probability
2.5%	0.0668	2.0%	0.0090
1.5%	0.2417	1.0%	0.2050
0%	0.3829	0%	0.5730
-1.5%	0.2417	-1.0%	0.2050
-2.5%	0.0668	-2.0%	0.0090

- Changing the economic and demographic uncertainty to a narrower distribution allows about 200 MW more flat load to be added to the system to achieve the same reliability level. **In summer months, this equated to about a 0.6 percentage point reduction in reserve margin.**

	Base Case (Flat Load) Original EDU			Base Case (Flat Load) Updated EDU		
Month	Demand Added (MW)	PRM	LOLE	Demand Added (MW)	PRM	LOLE
1	5,800	54.30%	0.0	6,000	53.32%	0.0
2	5,800	64.62%	0.0	6,000	63.59%	0.0
3	5,800	67.17%	0.0	6,000	66.13%	0.0
4	5,800	69.67%	0.0	6,000	68.64%	0.0
5	5,800	71.96%	0.0	6,000	70.93%	0.0
6	5,800	35.13%	0.0	6,000	34.49%	0.0
7	5,800	24.07%	0.0084	6,000	23.49%	0.0097
8	5,800	23.05%	0.0253	6,000	22.47%	0.0288
9	5,800	17.18%	0.0586	6,000	16.64%	0.0617
10	5,800	41.33%	0.0	6,000	40.56%	0.0
11	5,800	52.98%	0.0	6,000	52.04%	0.0
12	5,800	49.33%	0.0	6,000	48.42%	0.0
Total			0.0923			0.1002

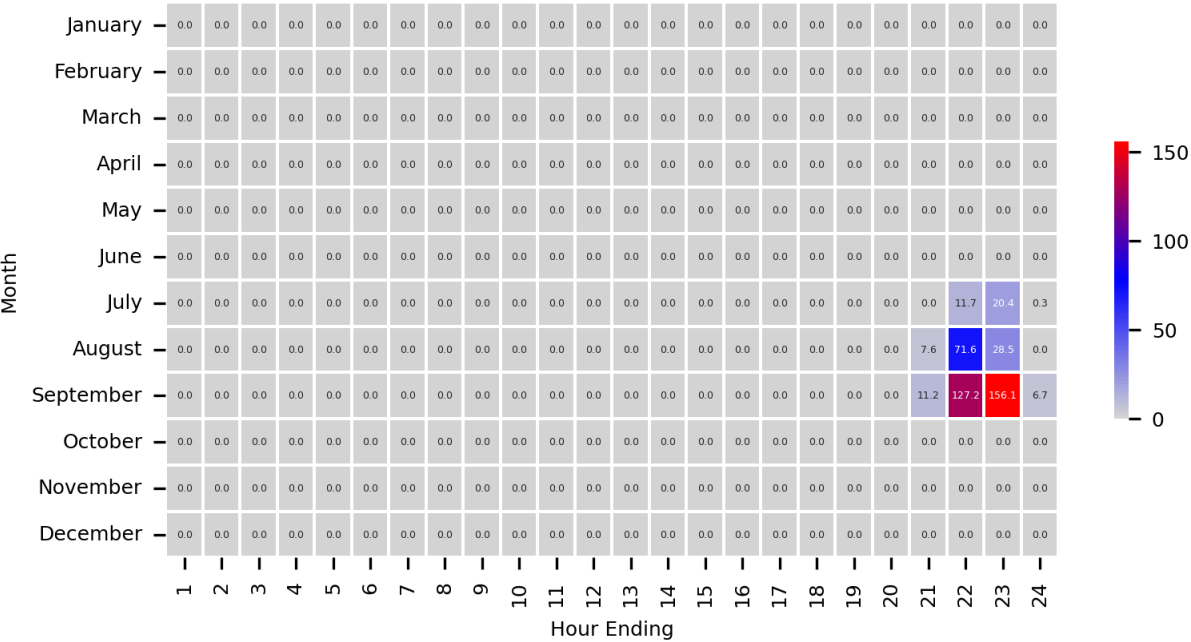
Tuned Base Case with prior EDU vs. updated EDU, Monthly LOLE Capacity

Annual Reliability Metrics	Base case, with prior EDU and 5.8 GW flat load added	Base case, with updated EDU and 6 GW flat load added	Units
	2028	2028	
LOLE Capacity	0.098	0.100	days/year
EUE	551.4	483.5	MWh
LOLH Capacity	0.190	0.196	hours/year
LOLH/LOLE (average length of outage)	1.928	1.960	hours/day

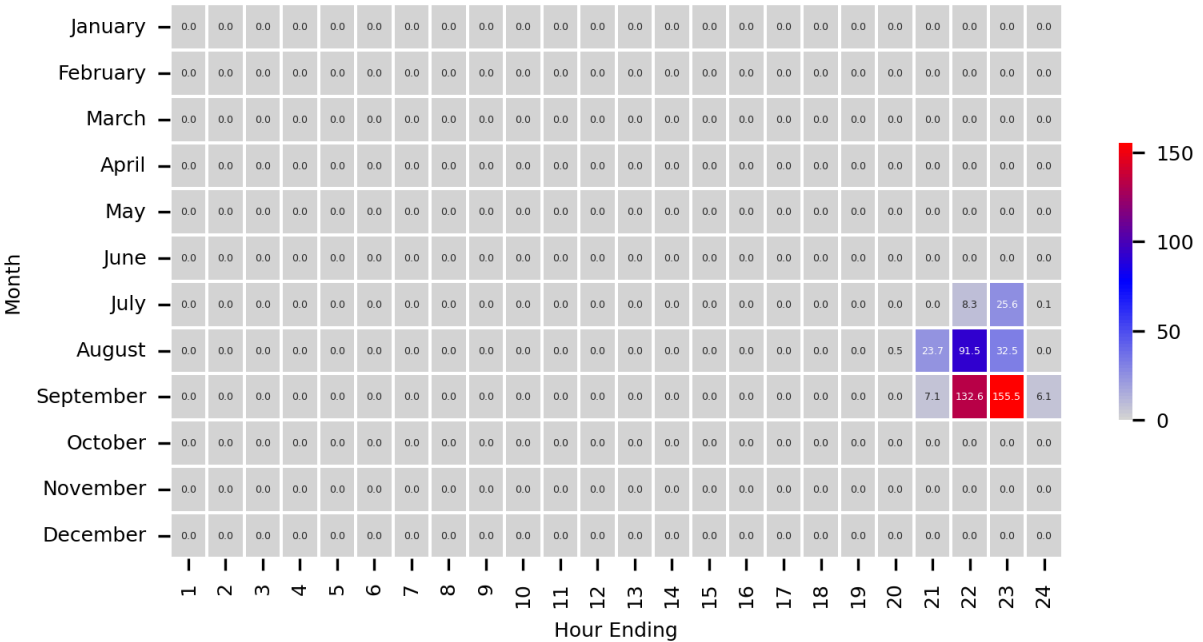


Tuned Base case with prior EDU distribution vs. updated EDU distribution, EUE Heatmap

Using prior EDU



Using updated EDU



Sensitivities to Test Input Update Impact

Thermal Ambient Output Derating

Monthly Stress Test Results for 2028 RA Study – Ambient Derates

With Thermal Derates No Maintenance

Month	Demand Added	PRM	LOLE
1	15,158	19.00%	0.0000
2	17,832	19.00%	0.0000
3	18,640	19.00%	0.0000
4	19,784	19.00%	0.0000
5	19,812	21.00%	0.0039
6	10,577	21.00%	0.0009
7	6,891	21.00%	0.0367
8	6,518	21.00%	0.0525
9	4,430	21.00%	0.0042
10	12,669	19.00%	0.0000
11	15,050	19.00%	0.0000
12	14,098	19.00%	0.0000
Total			0.0981

No Thermal Derates No Maintenance

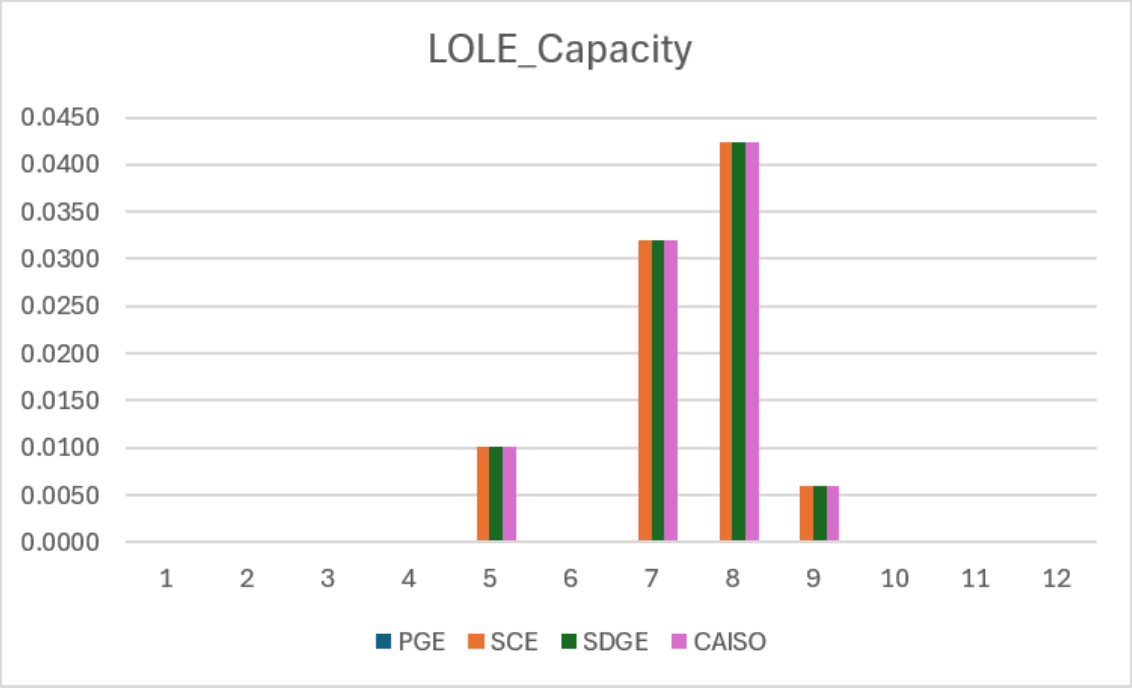
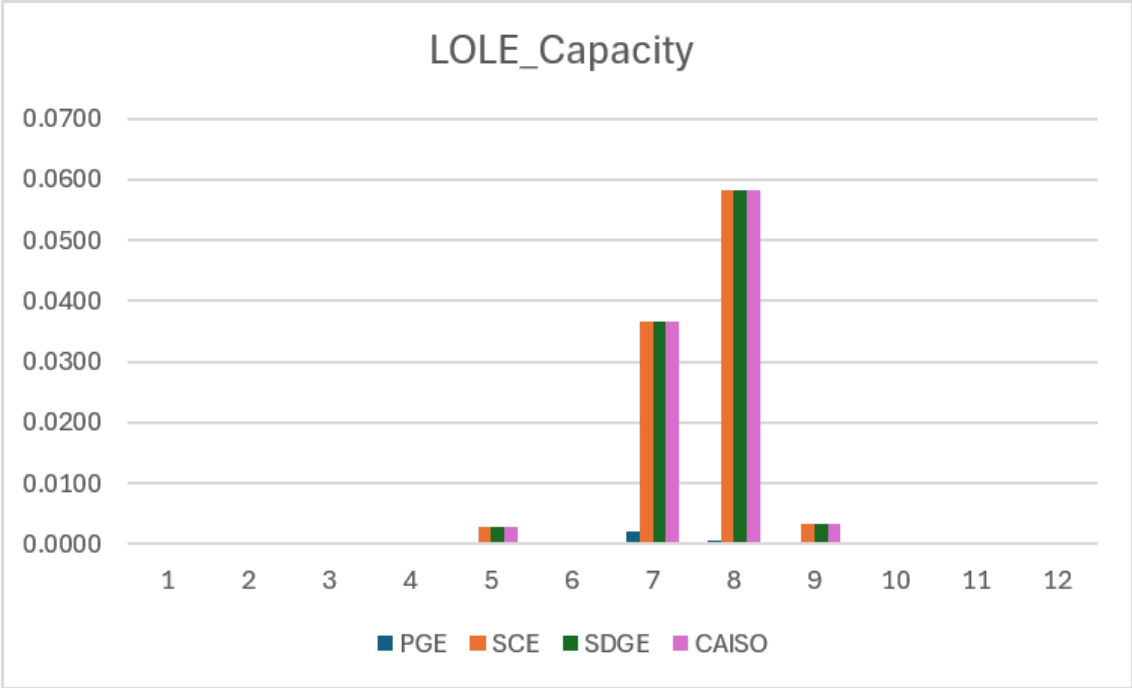
Month	Demand Added	PRM	LOLE
1	15,158	19.00%	0.0000
2	17,832	19.00%	0.0000
3	18,640	19.00%	0.0000
4	19,784	19.00%	0.0000
5	20,604	19.00%	0.0094
6	11,328	19.00%	0.0011
7	7,633	19.00%	0.0311
8	7,242	19.00%	0.0442
9	5,136	19.00%	0.0055
10	12,669	19.00%	0.0000
11	15,050	19.00%	0.0000
12	14,098	19.00%	0.0000
Total			0.0914

- Staff ran the Monthly Stress Test without including ambient derates, to test the impact of this new derate assumption on PRM level
- **Results show that the addition of ambient derates increases the PRM by about two percentage points**

Monthly LOLE Capacity for PGE, SCE and SDG&E

With Thermal Derates
No Maintenance

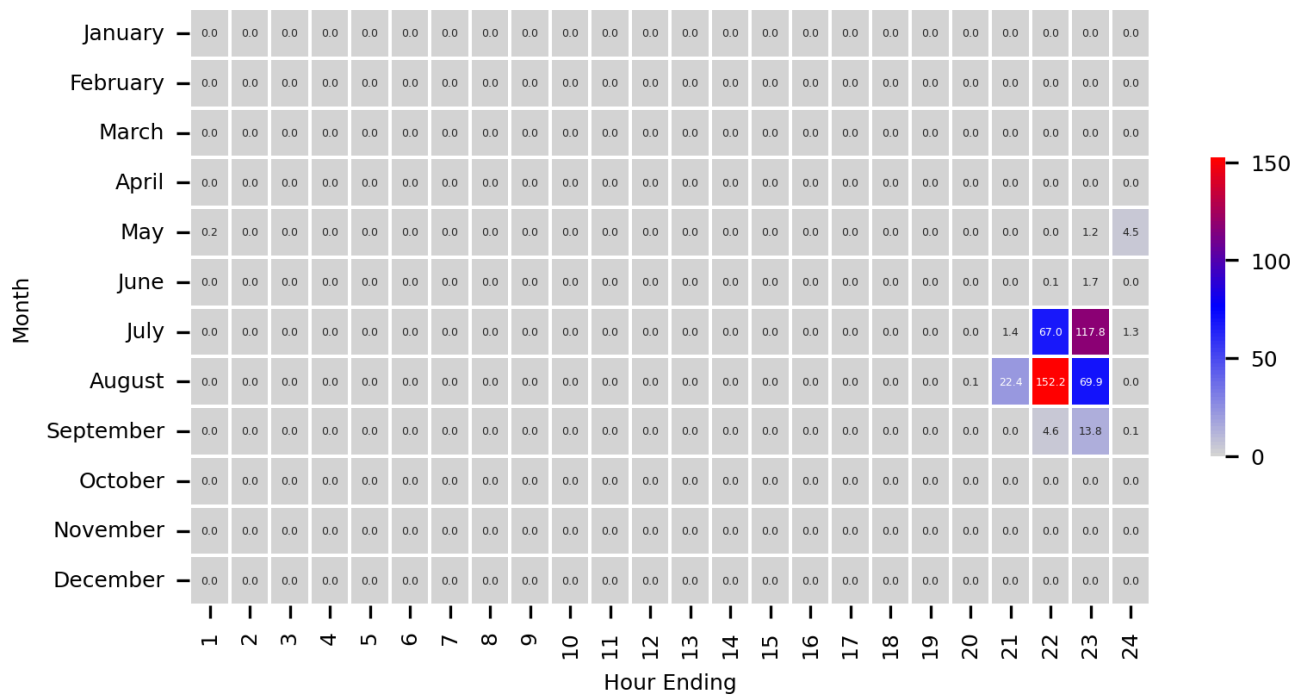
No Thermal Derates
No Maintenance



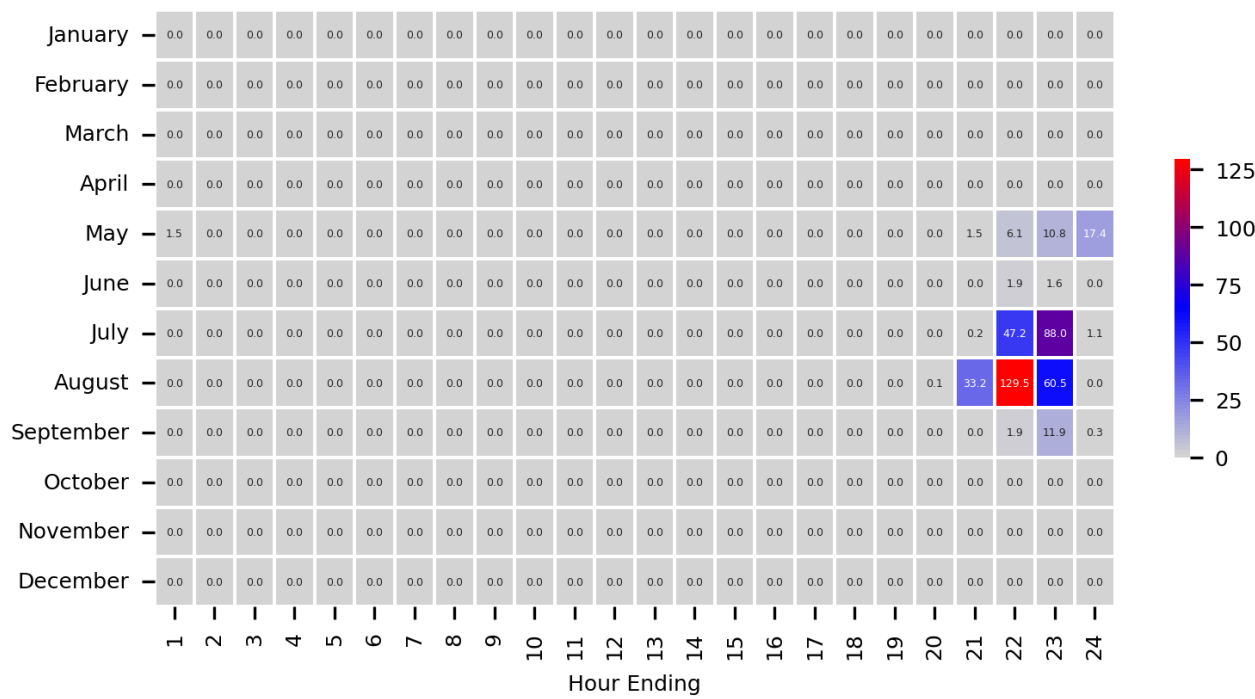
These are monthly Stress Test studies with varying demand blocks added each month, so not comparable to the annual studies with equal demand blocks each month.

EUE Heat map for Monthly Stress Tests

With Thermal Derates
No Maintenance



No Thermal Derates
No Maintenance



Conclusion, Next Steps

Conclusions

- **Correction to PRM Calibration Tool used for August Report:** Correcting an error in the PRM Calibration Tool resulted in decline in monthly PRM of about 4%
- **Annual LOLE results:** Employing multiple means of surfacing LOLE, staff found that the CAISO Baseline resource fleet updated in 2026 is over reliable by about 5-6 GW of effective capacity:
 - Adding flat load of about 6 GW achieves 0.1 LOLE
 - Tightening the peak hour/month CAISO simultaneous import constraint from 4 GW to 0 GW still results in LOLE < 0.1
 - A 95% capacity prorate (about 5.7 GW) achieves 0.1 LOLE
- **Monthly Stress Testing Results:** Adding varying blocks of demand in each month in SERVIM and then translating in the PRM Calibration Tool to a monthly PRM shows that a 21% PRM is required to maintain reliability for peak months, with a lower level 19% needed for off-peak months.
- **Sensitivity Results:** Sensitivity testing of key input changes from the prior RA study show that current results are generally consistent with the prior 2024 results because changes that raised reliability risks netted out changes that lowered reliability risks.
 - **Revised Econ-Demo Uncertainty Factors:** Using less extreme economic and demographic uncertainty factors reduces PRM by about 0.6 percentage points
 - **Revised unit forced outage rates:** Using revised forced outage rates based on CAISO not GADS data reduces PRM by about 1 percentage point
 - **Including Ambient Derates into modeling:** Using ambient derates for thermal power plants increases PRM by about 2 percentage points
- **UCAP capacity counting results and Final Stress Test PRM**
 - Applying EFORd + Ambient Temp. derate in UCAP PRM workbook reduces monthly stress tested PRM values to 13.6% - 16.4%

Next Steps for 2028 LOLE Study

- For the draft report, Staff reduced the number of random outage draws (iterations) from 50 to 30 to accelerate review times and complete this phase of the study. For the final report, Staff will perform the full 50 iterations across all scenarios in order to increase convergence and stability of the results.
- Staff will further investigate Prorate Scenario methodology and the different results of SCE's prorate modeling to produce final results for the October Final Report.
- Publish Final LOLE Study in October 2026 and include PRM recommendation for 2028–2029 RA compliance years.

Stakeholder Questions for Energy Division

Questions for Energy Division

- 1) The baseline portfolio used by Energy Division totaled 119,616 MW and SCE study had a portfolio of 109,544 MW. What is leading to the differences in the assumed portfolio?
 - The CAISO resources in the CPUC baseline total 119,616 MW. Of this total, the units with SERVM Regions PGE, SCE and SDGE total 108,634 MW. Differences in other parties' total MW likely reflect Staff's inclusion of specified imports listed in the Master Resource Database (MRD). Staff models far more than these resources as in the model, since staff models several regions external to CAISO to accurately assess import patterns.
- 2) Please discuss the UCAP assumptions that were used to derive the values in the UCAP-PRM workbook, do the UCAP values align with the UCAP proposal adopted in Track 1 of the proceeding?
 - Yes, the UCAP values align with the adopted UCAP proposal.
- 3) What methodological gaps persist with UCAP implementation that are absent from the UCAP-PRM results? For example, how was hybrid resource counting handled?
 - Track 2 seeks to resolve UCAP implementation issues such as UCAP application for hybrid resources. Current UCAP PRM results do not apply a derate to hybrid resources.
- 4) Can Staff explain how it grouped the summer months and why the PRM is higher in the summer months than non-summer months?
 - PRM is higher in summer months due to higher variability in weather that affects demand, and in forced and ambient outages that affect performance of power plants. Staff grouped months into summer and non-summer by LOLE results and necessary reserve levels.

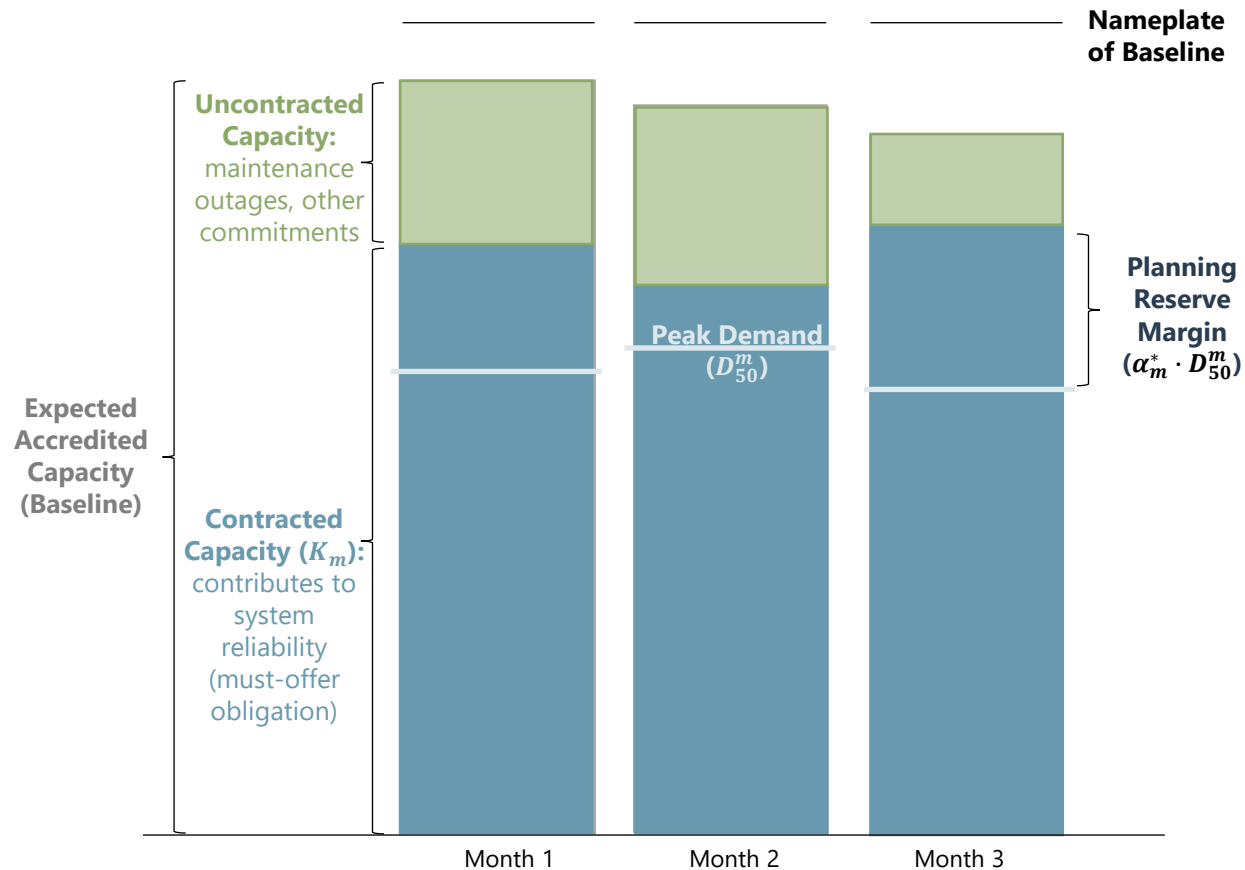
Questions for Energy Division

- 5) The monthly stress tests moved October into the higher summer month PRM group. Staff notes that adding load blocks can leave batteries unable to recharge across consecutive days. Is the October result an artifact of the demand-added method, or does the prorate approach produce the same result?
 - The correction to the profile shapes in the PRM tool and ensuing reruns of the stress tests showed reduced PRM in October, and October once again behaves like November and December. So, this issue is resolved.
- 6) Will ED be publishing a calibrated annualized PRM, in addition to the seasonal/monthly PRMs?
 - No, the off-peak months are able to have lower PRM levels than summer, so it is not necessary to have higher PRM in off-peak months.
- 7) Can Staff provide the intermediate steps used to reach 6,150 MW of added flat load (and, if available, capacity-reduction percentages used in Prorate Scenario), together with the monthly LOLE, EUE, and PRM at each step? Examining the sensitivity of LOLE to each increment is as important as the final calibration step.
 - Interim results are not available for party review at this time, as they are labor intensive to produce.
- 8) The Draft LOLE Study included both EFORd-only and EFORd-plus-ambient UCAP PRMs. Which convention will the Final Study use? Will Staff publish installed-capacity (ICAP) figures as well so parties can compare against previous studies?
 - Staff intends to publish UCAP-PRM values that are inclusive of EFORd + Ambient derates in the October report. In addition, ICAP PRM values will be published for comparison with previous studies.
- 9) Can Staff comment on the interaction between ambient thermal derates included in SERVIM and the ambient derate component of UCAP in the PRM Tool, to avoid double-counting or omitting heat-related derates.
 - Proper implementation of UCAP would require BOTH including UCAP and ambient derates in SERVIM modeling and using those derates for the PRM Calibration Tool so that reliability requirements and capacity accreditation are consistent.

CalCCA Draft 2028 Planning Reserve Margin Study

September 15, 2026

How Much Accredited Capacity Should be Shown in Each Month to Achieve Reliability?

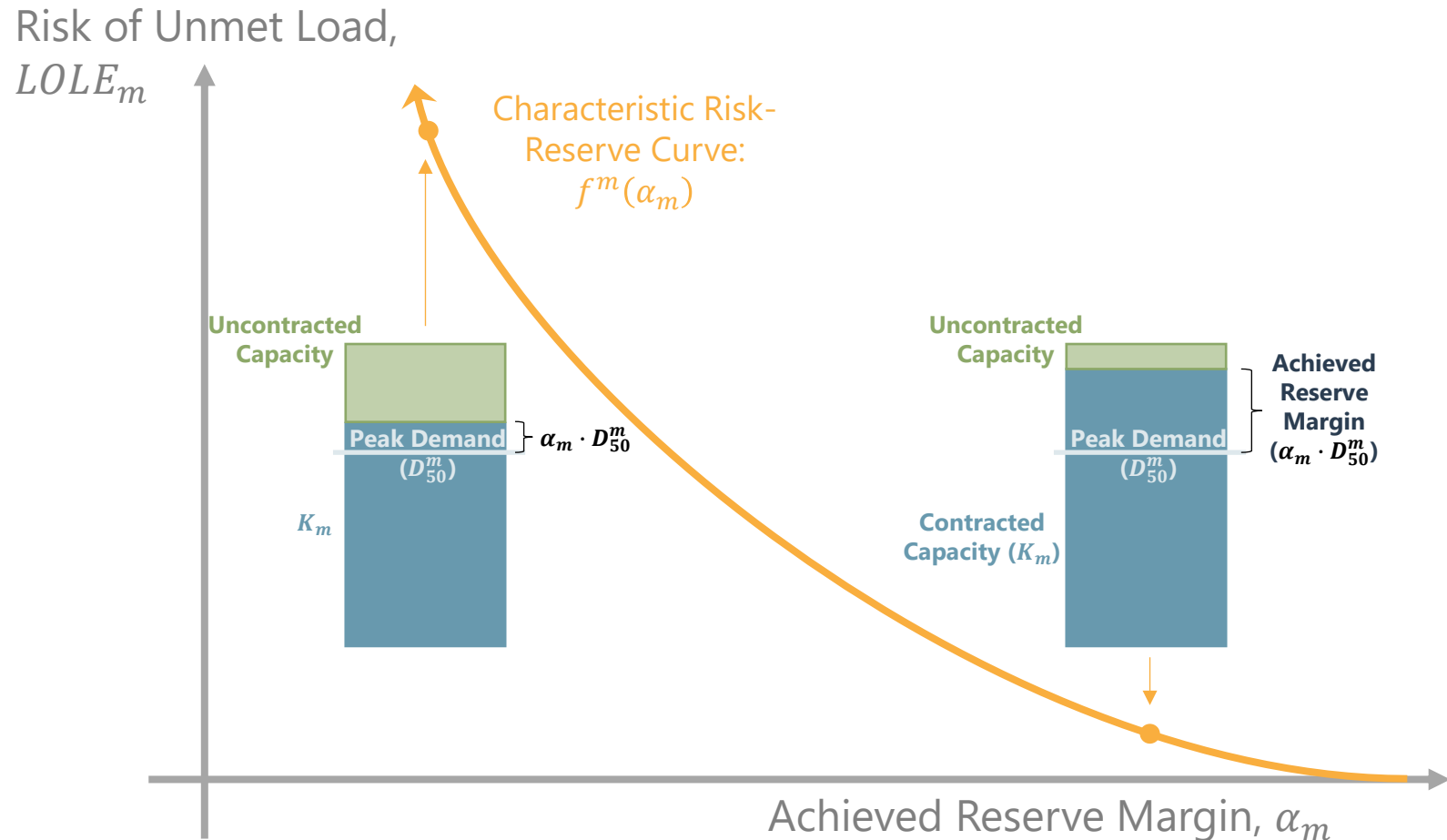


Motivating question:

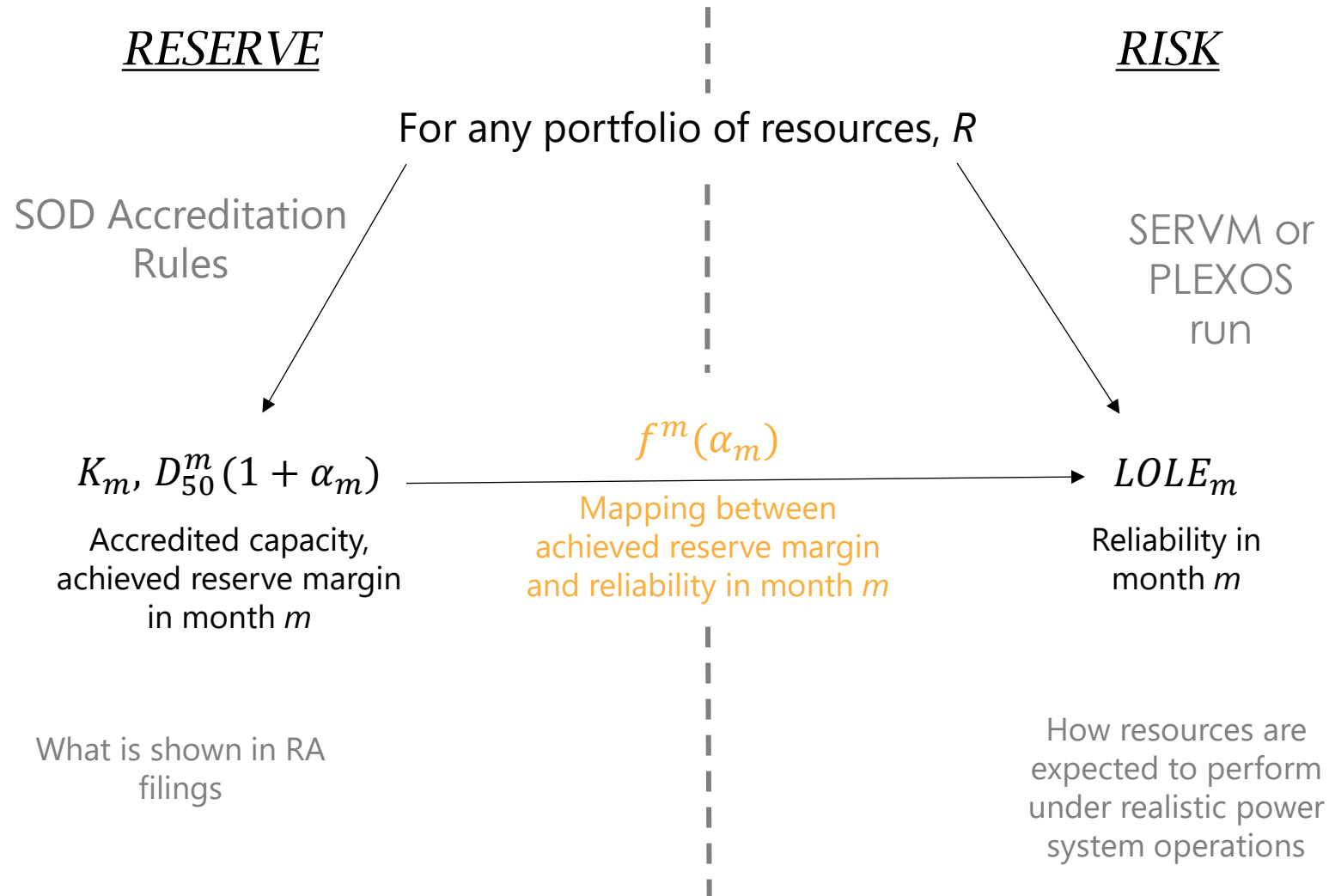
Based on the Slice-of-Day accreditation rules, how much of the accredited capacity of the expected fleet of resources should be shown in each month to achieve reliability (LOLE = 0.1), at least cost?

$$LOLE_m = f^m(\alpha_m): \quad 0.001 + 0.086 + 0.013 + \dots \leq 0.100$$

Risk-Reserve Curve Describes Relationship Between Achieved Reserve Margin and LOLE



Use Accreditation Rules and Probabilistic Reliability Model to Find the Risk-Reserve Curve



Example with Baseline Portfolio, R_B

Baseline achieves high reserve margins, no loss of load events observed in PLEXOS

Baseline Portfolio

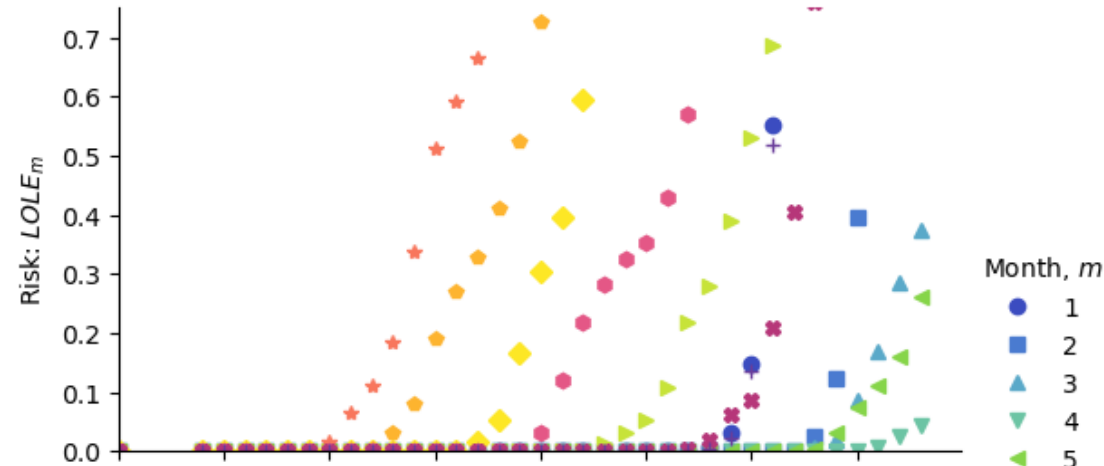
...in PRM Calibration Workbook

...in PLEXOS

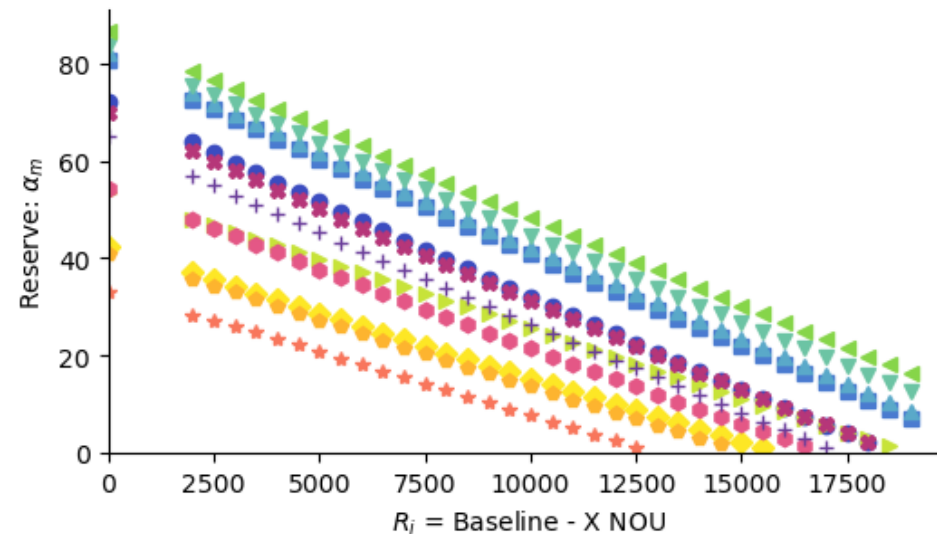
Unique identifier for resource portfolio, R_B	Month of the year	Monthly accredited capacity of resource portfolio R_B (MW)	Monthly 1-in-2 peak demand for 2028 (MW)	Monthly achieved reserve margin (%) for R_B , based on K_m and D_{50_m}	Risk of unmet load for R_B
R_B	Month	K_m	D_{50_m}	α_m	$LOLE_m$
Baseline	1	41,598	24,161	72.17	0.0000
Baseline	2	44,902	24,836	80.79	0.0000
Baseline	3	41,937	23,024	82.14	0.0000
Baseline	4	45,211	24,609	83.72	0.0000
Baseline	5	47,419	25,411	86.61	0.0000
Baseline	6	44,738	29,109	53.69	0.0000
Baseline	7	67,709	47,588	42.28	0.0000
Baseline	8	43,752	31,083	40.76	0.0000
Baseline	9	63,244	47,465	33.24	0.0000
Baseline	10	40,937	26,531	54.30	0.0000
Baseline	11	41,655	24,529	69.82	0.0000
Baseline	12	42,235	25,619	64.86	0.0000

How Do the Risk and Reserves Change As Resources Are Removed from the Baseline?

RISK:
PLEXOS runs

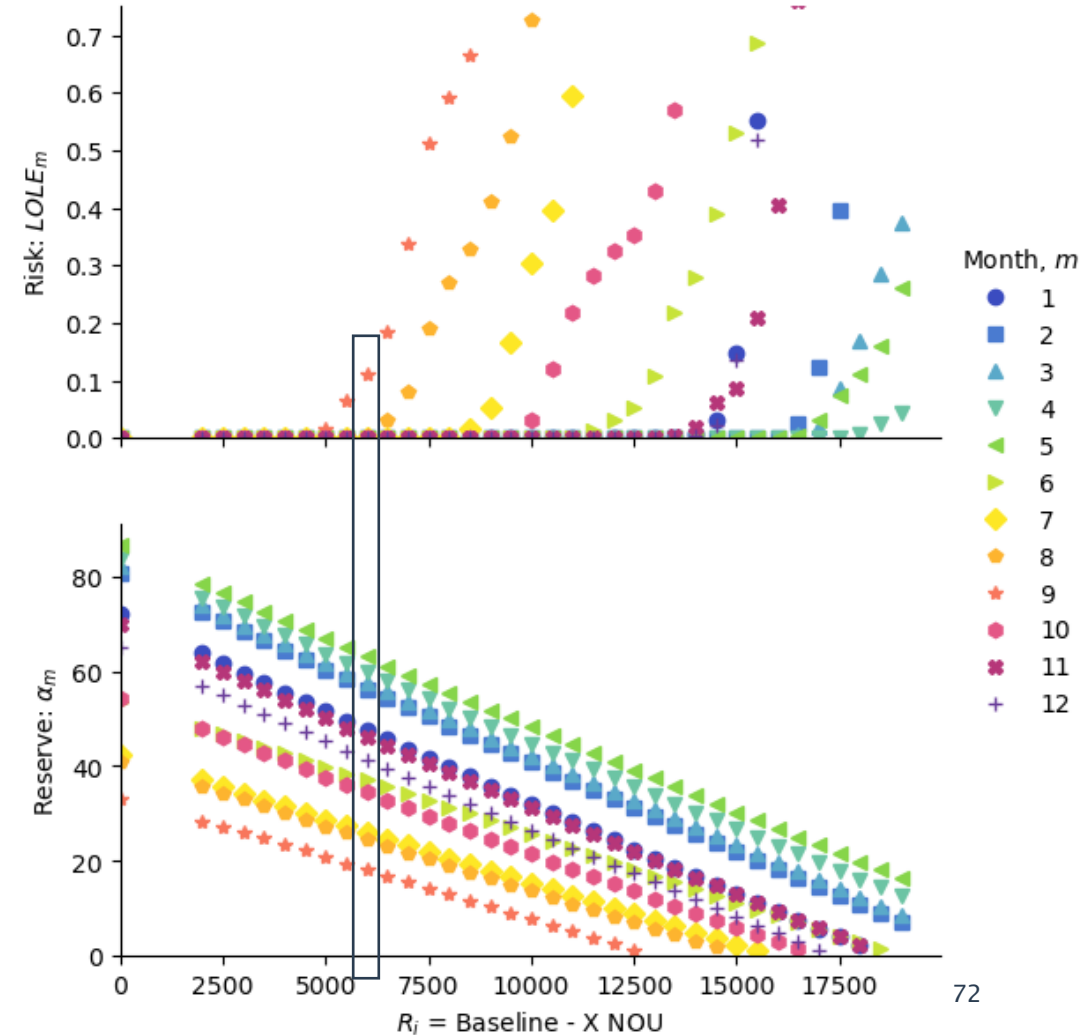


RESERVE:
SOD Accreditation
Rules



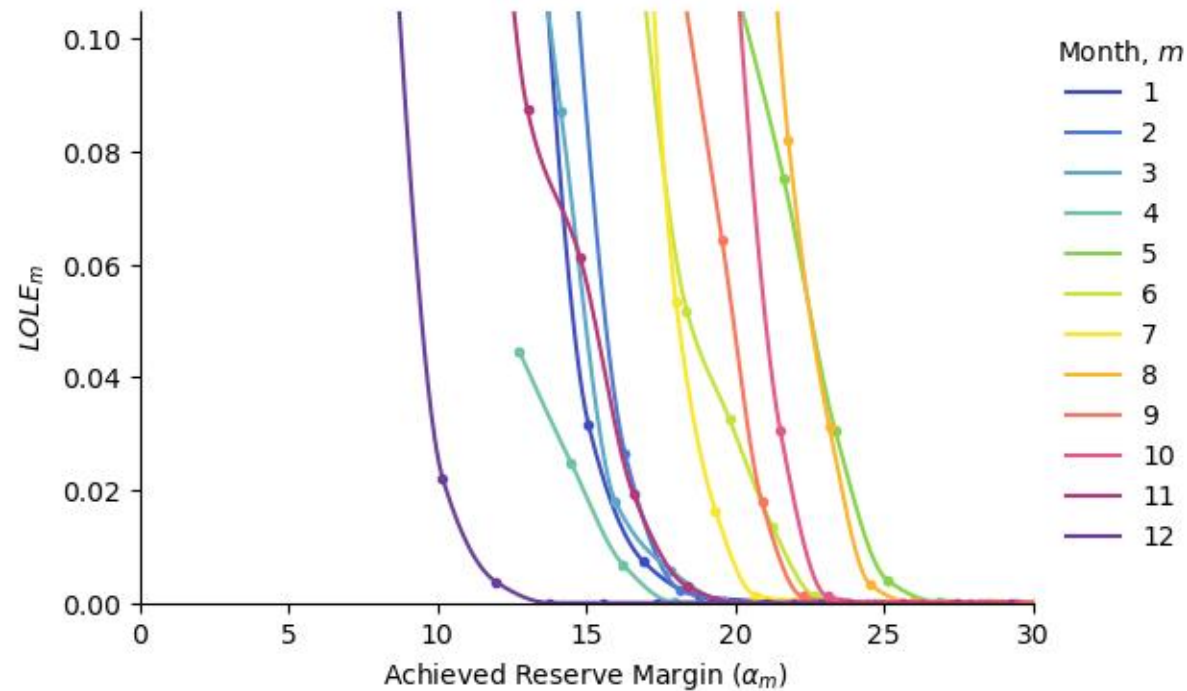
One of the CalCCA Draft Portfolios is Similar to the ED's Flat Load Case

Unique identifier for resource portfolio, R_i	Month of the year	Monthly accredited capacity of resource portfolio R_i (MW)	Monthly 1-in-2 peak demand for 2028 (MW)	Monthly achieved reserve margin (%) for R_i , based on K_m and D_{50_m}	Risk of unmet load for R_i
R_i	Month	K_m	D_{50_m}	α_m	$LOLE_m$
Remove 6000 MW	1	44,601	30,228	47.55	0.0000
Remove 6000 MW	2	46,522	29,762	56.31	0.0000
Remove 6000 MW	3	47,780	30,316	57.61	0.0000
Remove 6000 MW	4	52,138	32,624	59.81	0.0000
Remove 6000 MW	5	53,031	32,532	63.01	0.0000
Remove 6000 MW	6	59,060	43,089	37.06	0.0000
Remove 6000 MW	7	60,198	47,757	26.05	0.0000
Remove 6000 MW	8	58,209	46,739	24.54	0.0032
Remove 6000 MW	9	57,168	48,356	18.22	0.1100
Remove 6000 MW	10	52,748	39,235	34.44	0.0000
Remove 6000 MW	11	47,706	32,636	46.18	0.0000
Remove 6000 MW	12	43,628	30,849	41.42	0.0000

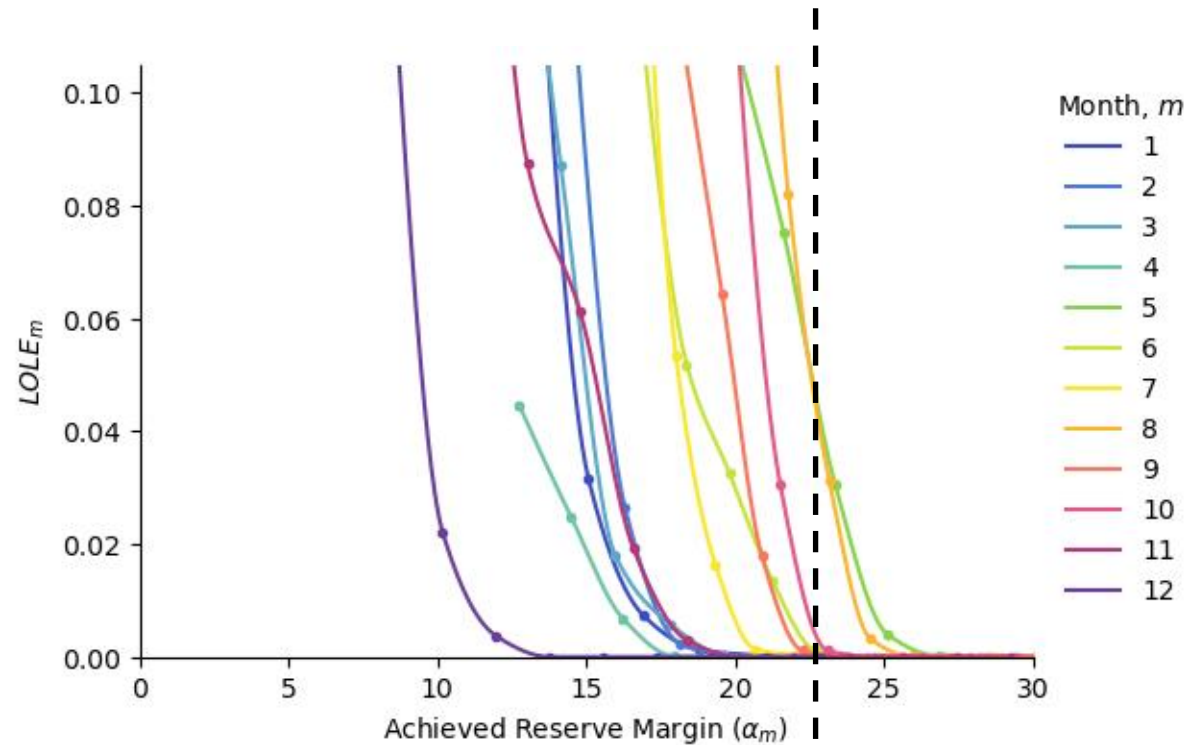


From CalCCA's DRAFT Study: Final Results will Differ

Put Results from All Portfolios Together to Create Risk-Reserve Curve Each Month m



Risk-Reserve Curves Illustrate Challenge of Single Annual PRM



m	D_{50}^m	α^*_m	$D_{50}^m(1+\alpha^*_m)$	LOLE _{m}
1	30,228	22.7%	37,077	-
2	29,762	22.7%	36,506	-
3	30,316	22.7%	37,185	-
4	32,624	22.7%	40,016	-
5	32,532	22.7%	39,904	0.0475
6	43,089	22.7%	52,853	0.0012
7	47,757	22.7%	58,578	0.0001
8	46,739	22.7%	57,330	0.0461
9	48,356	22.7%	59,313	0.0006
10	39,235	22.7%	48,125	0.0045
11	32,636	22.7%	40,031	-
12	30,849	22.7%	37,839	-
Total RA Cost - Monthly (\$ 000s/yr)				\$ 6,459,223
Total RA Cost - Annual (\$ 000s/yr)				\$ 7,612,254
Total LOLE				0.1000

22.7% Annual PRM
Meets 0.1 LOLE

From CalCCA's DRAFT Study: Final Results will Differ

Planning Reserve Margin Problem

- Choose α_m^* [planning reserve margin in each month] to:

minimize $\sum_m D_{50}^m (1 + \alpha_m) \cdot p_K^m$ [Least Cost]

such that: $\sum_m f^m(\alpha_m) \leq 0.1$ [Reliable]

Where:

D_{50}^m Peak 1-in-2 demand in month m

p_K^m Price of accredited capacity in month m

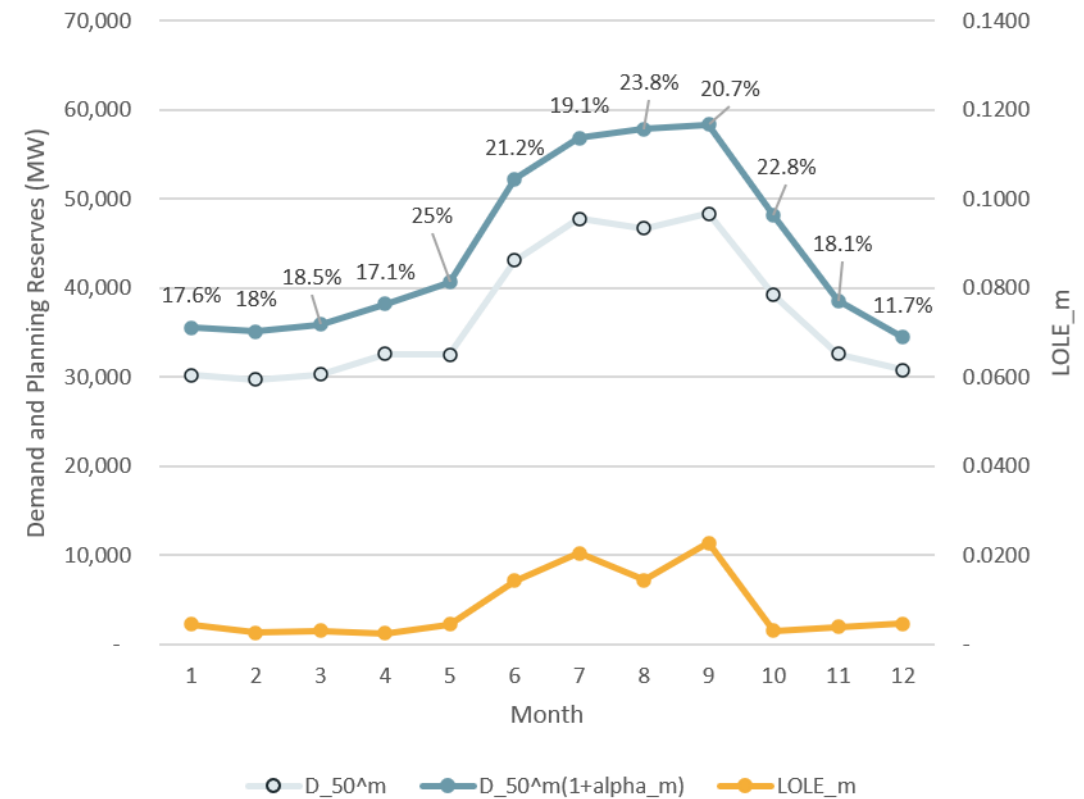
α_m Achieved reserve margin in month m

$f^m(\alpha_m)$ function of achieved reserve margin in month m to LOLE in m

Option 1: Monthly Reserve Margin from Monthly RA Costs

m	p_K^m	D_50^m	alpha*_m	D_50^m(1+alpha*_m)	RA Cost_m	LOLE_m
1	\$ 5.7	30,228	17.6%	35,535	\$ 201,126	0.0044
2	\$ 5.7	29,762	18.0%	35,132	\$ 198,847	0.0027
3	\$ 5.4	30,316	18.5%	35,923	\$ 192,550	0.0031
4	\$ 5.8	32,624	17.1%	38,190	\$ 223,029	0.0025
5	\$ 7.1	32,532	25.0%	40,674	\$ 290,007	0.0044
6	\$ 10.8	43,089	21.2%	52,216	\$ 563,931	0.0142
7	\$ 17.5	47,757	19.1%	56,884	\$ 995,472	0.0204
8	\$ 21.4	46,739	23.8%	57,871	\$ 1,240,179	0.0142
9	\$ 24.1	48,356	20.7%	58,365	\$ 1,404,850	0.0225
10	\$ 11.4	39,235	22.8%	48,173	\$ 547,732	0.0030
11	\$ 6.5	32,636	18.1%	38,555	\$ 250,994	0.0039
12	\$ 7.0	30,849	11.7%	34,472	\$ 241,649	0.0047
					Total RA Cost (\$ 000s/yr)	Total LOLE
					\$ 6,350,368	0.1000

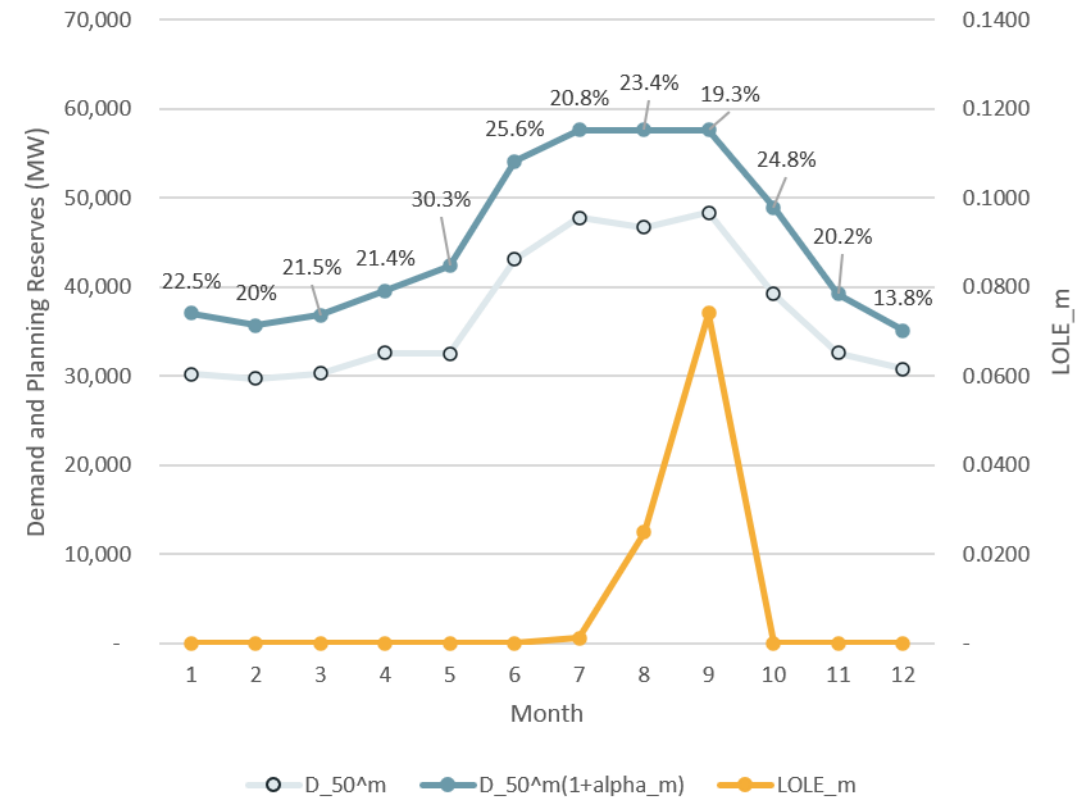
Option 1:
Monthly Reserve Margin from Monthly RA Costs



Option 2: Monthly Reserve Margin from Annual RA Costs

m	D_50^m	alpha*_m	D_50^m(1+alpha*_m)	LOLE_m
1	30,228	22.5%	37,040	0.0000
2	29,762	20.0%	35,719	-
3	30,316	21.5%	36,828	0.0000
4	32,624	21.4%	39,594	0.0000
5	32,532	30.3%	42,401	0.0000
6	43,089	25.6%	54,103	0.0000
7	47,757	20.8%	57,679	0.0012
8	46,739	23.4%	57,679	0.0247
9	48,356	19.3%	57,679	0.0740
10	39,235	24.8%	48,950	-
11	32,636	20.2%	39,222	0.0000
12	30,849	13.8%	35,101	-
Highest RA Requirement			57,679	Total LOLE
Annual RA Price (\$/kW-yr)			\$ 128.3	0.1000
Total RA Cost (\$ 000s/yr)			\$ 7,402,537	

Option 2:
Monthly Reserve Margin from Annual RA Costs

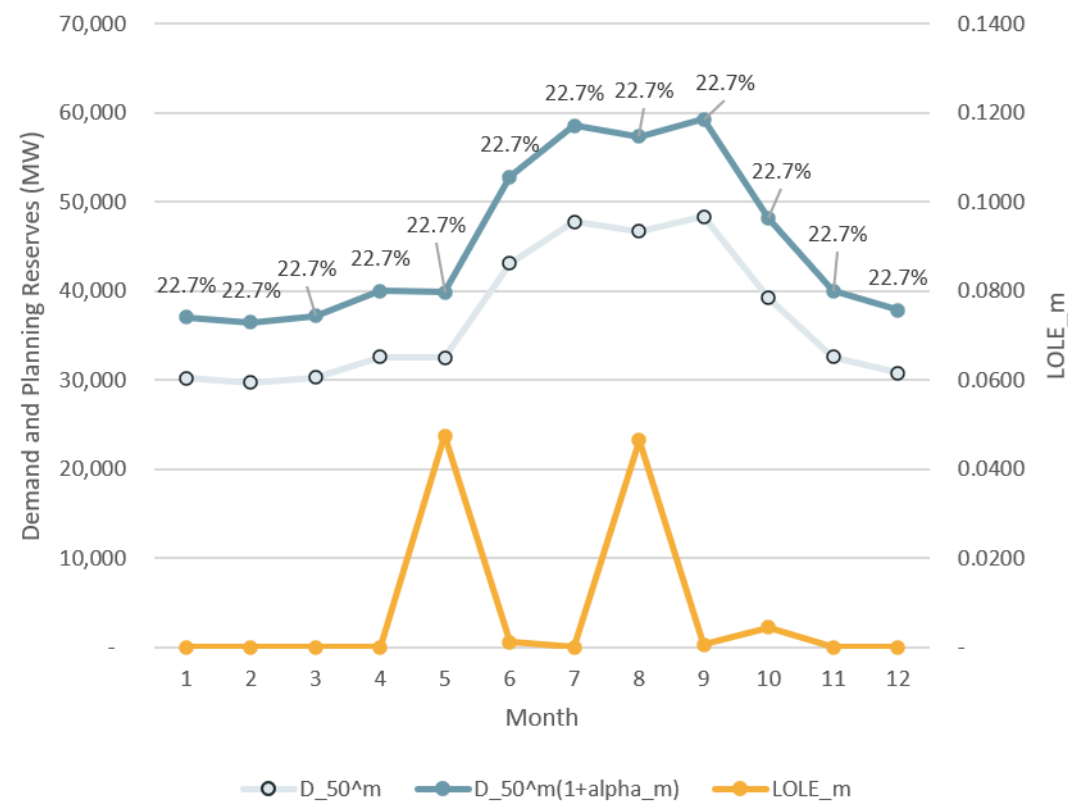


Option 3: Annual Reserve Margin

m	D_50^m	alpha*_m	D_50^m(1+alpha*_m)	LOLE_m
1	30,228	22.7%	37,077	-
2	29,762	22.7%	36,506	-
3	30,316	22.7%	37,185	-
4	32,624	22.7%	40,016	-
5	32,532	22.7%	39,904	0.0475
6	43,089	22.7%	52,853	0.0012
7	47,757	22.7%	58,578	0.0001
8	46,739	22.7%	57,330	0.0461
9	48,356	22.7%	59,313	0.0006
10	39,235	22.7%	48,125	0.0045
11	32,636	22.7%	40,031	-
12	30,849	22.7%	37,839	-
Total RA Cost - Monthly (\$ 000s/yr)			\$ 6,459,223	Total LOLE
Total RA Cost - Annual (\$ 000s/yr)			\$ 7,612,254	0.1000

Annual PRM raises costs by 1.7% to 2.8% relative to monthly PRMs

Option 3:
Annual Reserve Margin

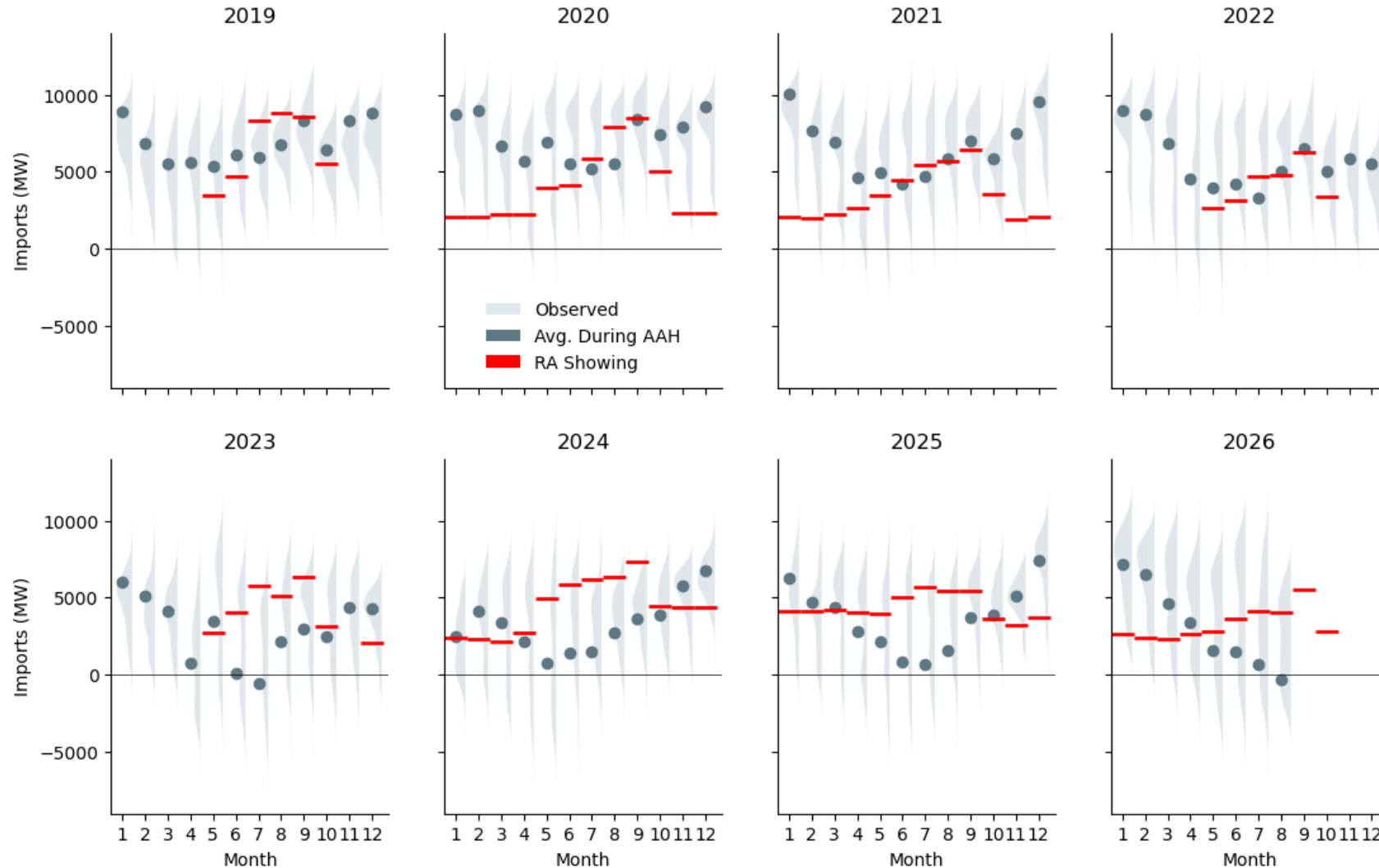


Revisions to Assumptions for CalCCA's Final 2028 PRM Study

Draft Studies Differ on Imports in Probabilistic Modeling (Risk) and Accreditation (Reserve)

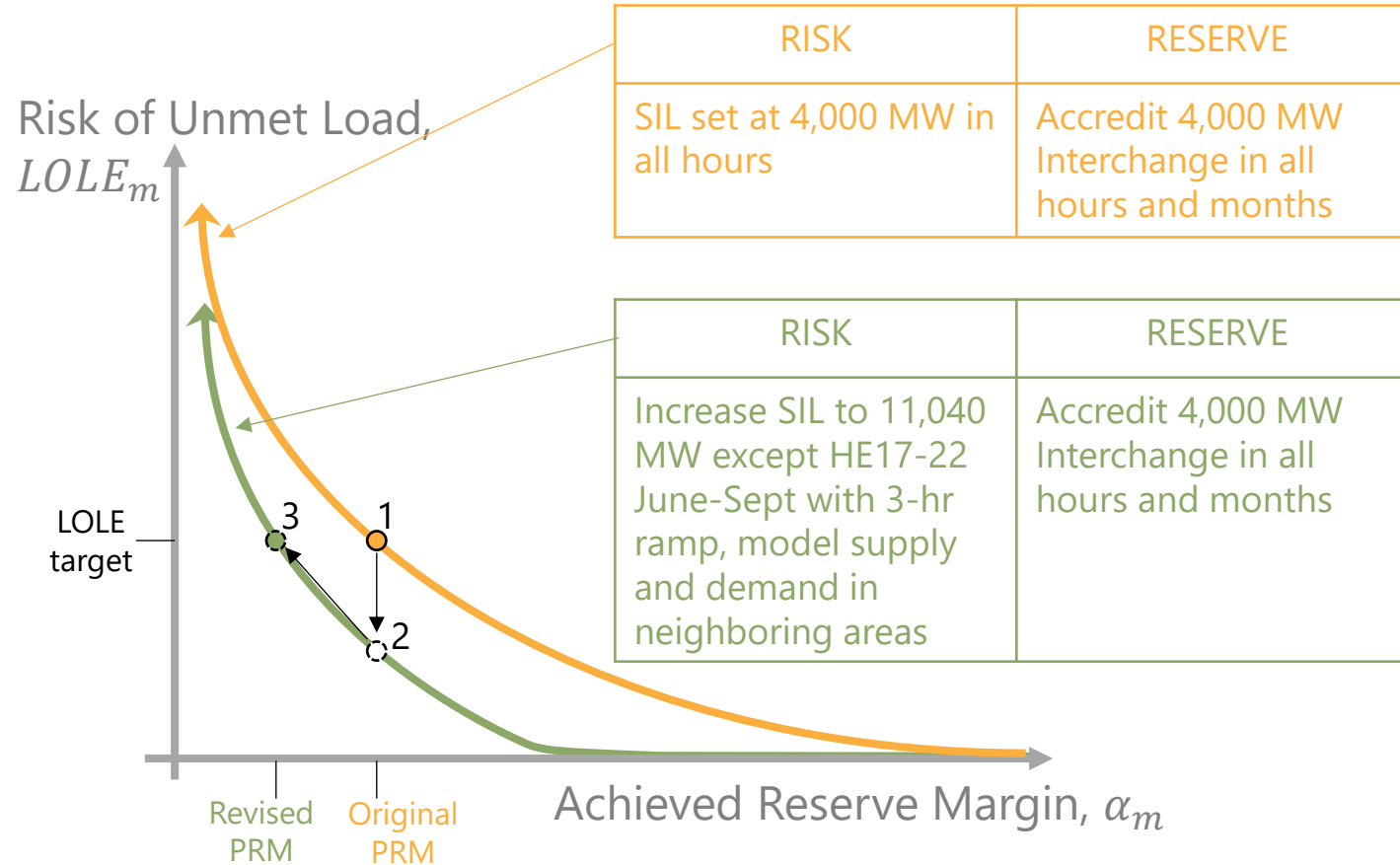
Study	Risk: Probabilistic Modeling	Reserve: Accreditation
CalCCA Draft	Assume 4,000 MW imports available in all hours.	Interchange adds 4,000 MW accredited capacity in all months and hours.
SCE Draft	Assume imports available up to 4,000 MW from 5pm-10pm with three-hour ramp to 11,040 MW limit in off-peak hours for all months. Scaled down by 19% in calibration.	Interchange adds 4,000 MW from 5pm-10pm with three-hour ramp to 11,040 MW limit in off-peak hours for all months. Scaled down by 19% in calibration.
ED Draft	Model supply and demand in neighboring balancing authorities. For June-September, simultaneous import limit set to 4,000 MW from 5pm-10pm with three-hour ramp to 11,040 MW in off-peak hours. In other months imports allowed up to 11,040 MW in all hours.	Interchange adds 4,000 MW of accredited capacity in June-September in all hours with 11,040 MW of accredited capacity in other months for all hours.

Historical Data Show Observed Imports (Risk) Often Exceed Accredited RA Imports (Reserve)



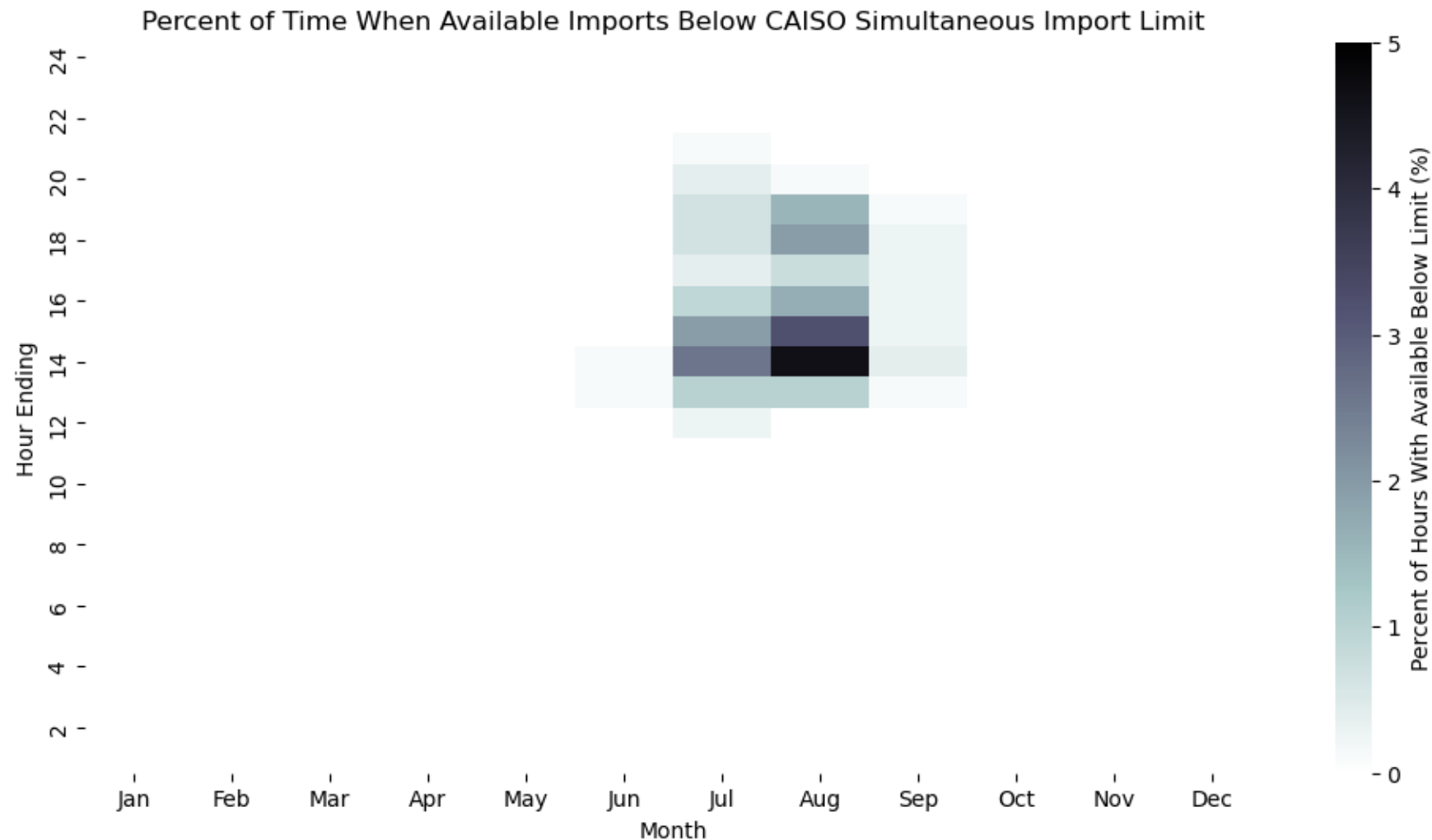
Implications of Allowing Imports up to Simultaneous Import Limit (SIL) in Probabilistic Modeling

1. PRM from solving PRM Problem used risk-reserve curve where PLEXOS included 4,000 MW of imports available in all hours
2. Increasing the SIL in PLEXOS will lower LOLE without changing achieved reserve margin
3. Using the lower, revised risk-reserve curve in the PRM problem allows lower PRM to meet the original LOLE



2028 Baseline Suggests Ample Resources Outside of CAISO to Supply Imports

SIL defined as 11,040 MW, decreasing to 4,000 MW in June-September for HE17-22 with three-hour ramp



Possible Revisions for CalCCA's Final Study

- Modify CalCCA's PLEXOS model to incorporate weather-dependent supply and demand in neighboring balancing authorities
- Increase Simultaneous Import Limit to 11,040 MW in non-summer months, decrease to 4,000 MW in HE17 to HE22 of June-September with three hour ramp
- Update generating unit capacity to most recent baseline
- Update reserve calculations to use UCAP+ambient accreditation
- Use sensitivity studies to show impact of different RA price assumptions on Option 1 PRM

CalCCA RA Track 2 Proposal: Effective PRM Removal

September 15, 2026

The Commission Should Eliminate the Effective PRM

- The “Effective PRM” is a non-binding RA requirement assigned to the IOUs above their own RA requirements, with costs assigned to all LSEs
 - The Effective PRM was adopted in 2021 to meet “a need for an increase in supply side resources in light of the weather experienced throughout the summer of 2020 and in anticipation of more frequent extreme weather events resulting from climate change.”
- The Effective PRM mechanism is flawed and unnecessary:

Drives up costs when RA supply is tight by adding artificial demand

Does not allow the CAISO to backstop for RA deficiencies within the Effective PRM range

Allows for deviation from 0.1 LOLE standard (e.g., Resolution E-5467)

Creates uneven playing field across LSEs by allowing resources to shift between effective PRM and bundled portfolio

Encroaches on CCA procurement autonomy provided in Section 380

The Commission Should Instead Adopt a Uniform PRM for All LSEs

- ✓ Remove the effective PRM in its entirety;
- ✓ Perform robust LOLE modeling with opportunities for parties to submit their own studies and provide input to inform the PRM; and
- ✓ Set a single PRM for all LSEs that ensures the RA program meets a 0.1 LOLE standard or similarly robust metric.

Break for Lunch

12:30pm – 1:30pm

CPUC Resource Adequacy Proceeding | September 15, 2026 Workshop

SCE's 2028 LOLE Study Draft Results

September 15, 2026



Executive Summary

- **SCE's calibrated 2028 portfolio effectively meets the 1-in-10 LOLE standard and translates to an implied September PRM of 16.4%.**
 - SCE independently modeled the CPUC 2028 baseline portfolio in PLEXOS using Energy Division inputs and assumptions.
 - The baseline portfolio produced no modeled loss-of-load events, indicating **reliability above the 0.1-event/year LOLE** criterion.
 - To calibrate the portfolio toward the 0.1 LOLE reliability standard, SCE applied **pro rata capacity reductions across most non-hydro resource categories** including imports. The calibration reduced approximately **21 GW** of capacity and produced a base-case LOLE of **0.085 event/year**.
 - Incorporating the five-point Economic and Demographic Uncertainty (EDU) increased the probability-weighted LOLE to **0.096 event/year**, effectively meeting the 0.1 LOLE standard.
 - Modeled reliability risk is concentrated in July through September and HE 16 through HE 24.

Two-Step LOLE-to-PRM Methodology

First establish the portfolio that meets the reliability standard, then translate that same portfolio into a PRM in SOD tool.

1

Determine the reliability-standard portfolio

Calibrate resource portfolios using the LOLE model until the portfolio approximately meets the **1-in-10** reliability criterion.

Output

A calibrated portfolio with modeled reliability approximately with the 0.1-event/year LOLE standard.



Same portfolio and consistent assumptions

2

Translate the portfolio into PRM

Enter the calibrated portfolio into the **Slice-of-Day (SOD) tool** and calculate the implied PRM for the constraining hour and month.

Output

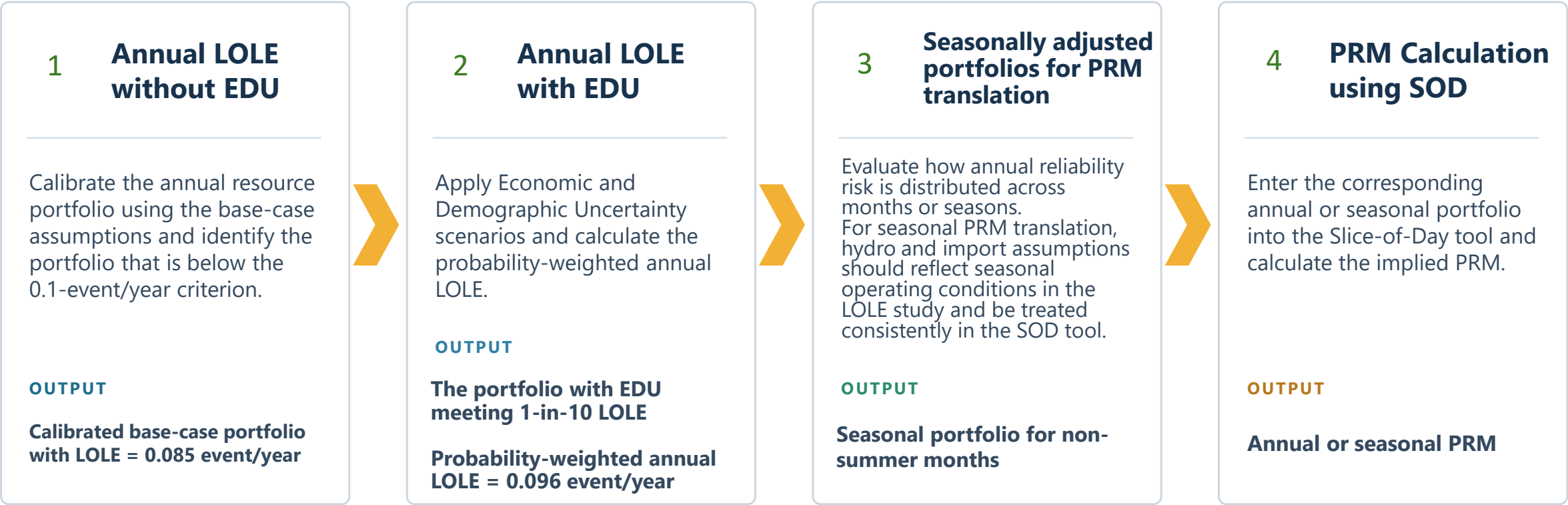
An implied PRM under the Slice-of-Day framework.

Why consistency between the two steps matters

The SOD translation should preserve the calibrated portfolio and use consistent load, resource accreditation, import treatment, and hourly profiles of renewables. Otherwise, the resulting PRM may no longer represent the portfolio that achieved the 1-in-10 LOLE standard.

Detailed Annual and Seasonal LOLE-to-PRM Workflow

The two-step framework is implemented through four analytical stages to address annual reliability, EDU, and seasonal PRM requirements.



Annual reliability is established first; seasonal analysis and Slice-of-Day translation then convert the reliability results into PRM values.

Consistency principle

Each PRM translation should use the portfolio and assumptions associated with the corresponding LOLE analysis. For Seasonal PRM study, hydro and Import should consider its seasonable pattern in the LOLE study and corresponding accreditation in the SOD tool.

Getting an over-reliable RA system back to 1-in-10

PRM = (Resources – Load) / Load

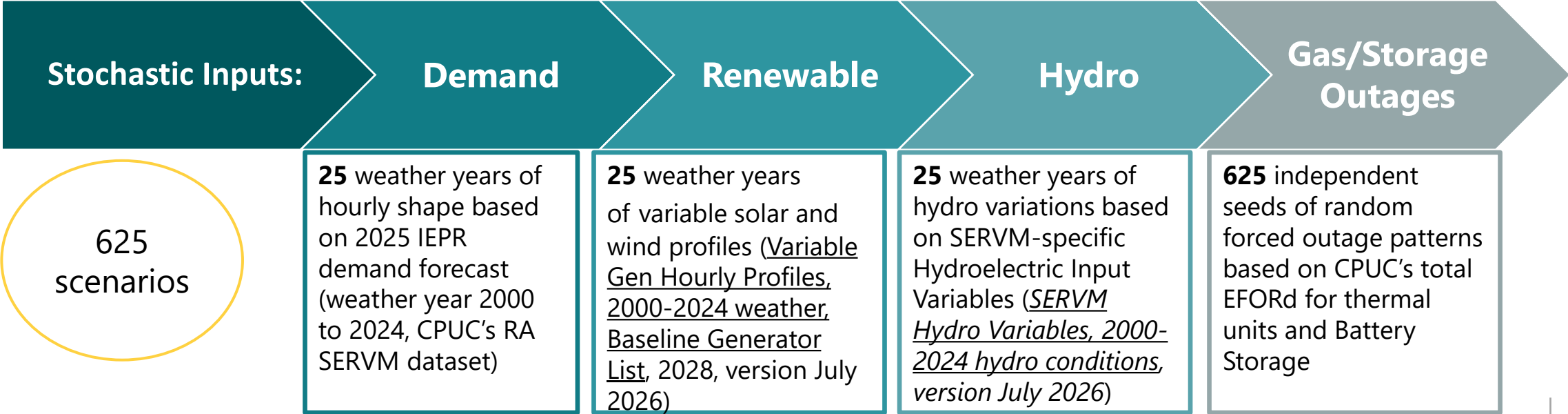
A PRM study should answer: “how much resource is needed for the forecast load (IEPR 1-in-2)?”

Pro-rata resource reduction		Adding load blocks
Stresses the portfolio by shrinking supply		Stresses the portfolio by changing demand
Issue	Pro-rata resource reduction	Adding load blocks
Official IEPR load forecast	Unchanged	Artificially increased
Question being answered	“How much portfolio is required?”	“How much additional demand could this portfolio serve?”
Portfolio composition	Can be held approximately constant	Fixed
Load shape/energy	Preserved	Altered
Storage charging/energy constraints	Reflect original forecast	Can be materially changed
What it tells you		What it tells you
“How much RA portfolio is needed for this load?”		“How much extra load could this portfolio serve?”
Better match to PRM: load is fixed; only the resource numerator moves.		Problem: the load shape, energy need, storage charging, and PRM denominator all move.

Takeaway: load blocks measure headroom; pro-rata reduction measures the RA requirement. Pro-rata resource reduction is a better calibration method for California electric system.

2028 LOLE Modeling Framework and Stochastic Design

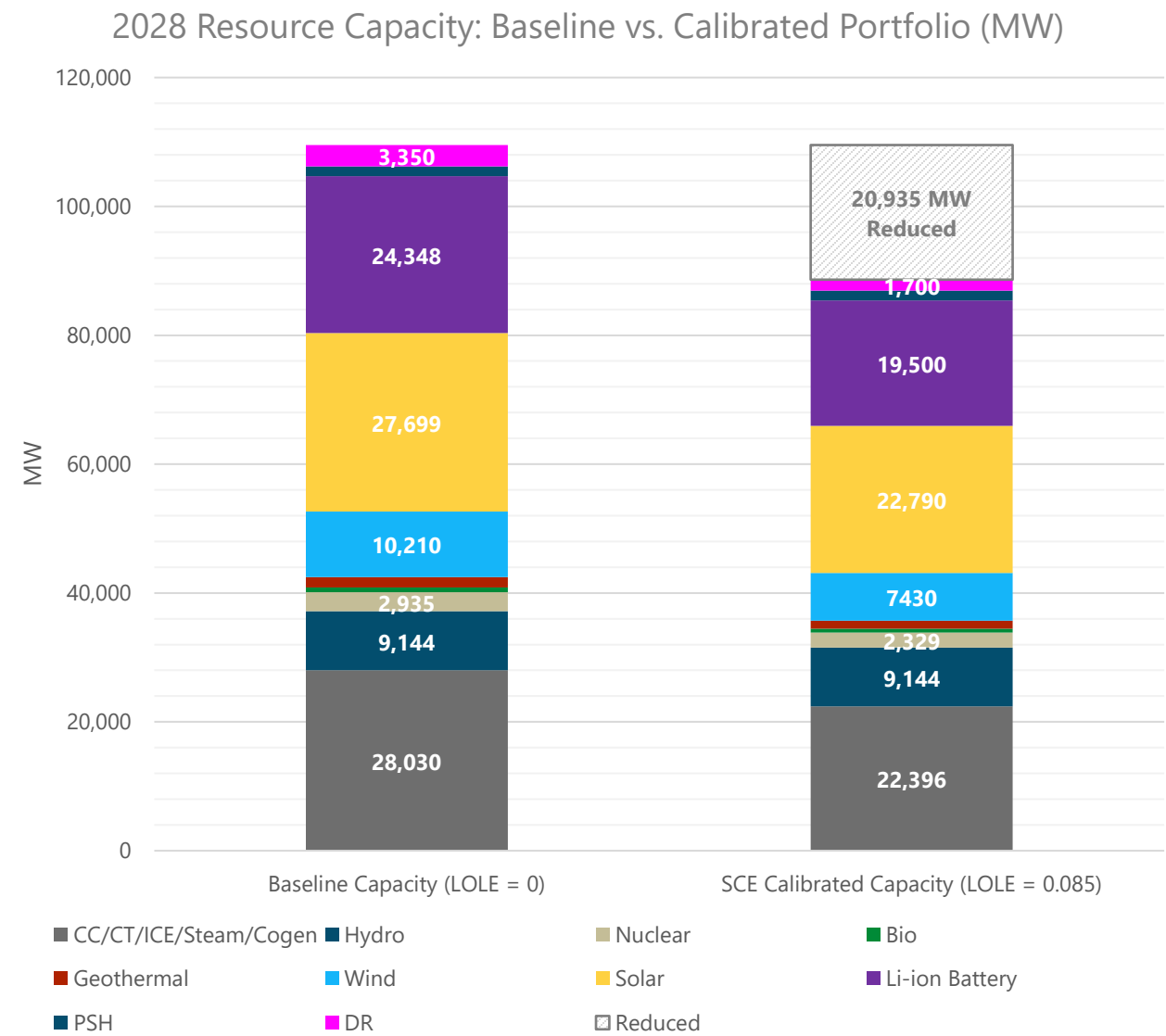
- SCE conducted a 2028 Loss-of-Load Expectation (LOLE) assessment in PLEXOS, running Monte Carlo simulations across 625 stochastic cases to evaluate system reliability under both load and generation uncertainty, consistent with CPUC’s methodology.
 - ❑ Paired **25** weather years of load shapes with **25** weather years of renewable and hydro profiles
 - ❑ 25 weather years × 25 independent outage realizations = 625 stochastic cases
 - ❑ Modeled uncertainty in **load, wind and solar generation, hydro conditions, and generator and storage outages**
- CPUC resource-type-specific seasonal total EFORd assumptions from the January 2026 UCAP Evaluation Workbook were applied to thermal and storage resources.
 - ❑ Total EFORd includes both non-ambient EFORd and weather-normalized ambient-temperature derates for thermal resources



Key Assumption Changes from SCE's 2026 RA Study

ASSUMPTION	2026 RA STUDY		2028 RA STUDY
CPUC INPUTS & BASELINE	2026 RA baseline 23 weather years (2000–2022) 2023 IEPR demand forecast - Earlier solar, wind and hydro profiles vintages	→	2028 RA baseline (~ 17GW additional resources) 25 weather years (2000–2024) 2025 IEPR demand forecast - Updated solar, wind, hydro profiles
STOCHASTIC DESIGN	23 renewable weather-years × 23 independent hydro & load weather years 529 outage draws 529 stochastic cases	→	25 renewable weather-years paired with hydro and load 625 outage draws 625 stochastic cases
FORCED OUTAGE RATES	CPUC capacity-weighted forced outage rates (gas & storage), summer / non-summer	→	- CPUC resource-type-specific seasonal EFORD - Non-ambient EFORD + weather-normalized ambient derates
ANCILLARY SERVICES	CAISO DAM historical AS requirement for regulation up/down & spinning reserve	→	3% of hourly demand for regulation up/down & 3% of spinning reserve based on CPUC's methodology
IMPORT CONSTRAINTS	11,040 MW (all hours), 4,000 MW (5–10pm, summer months only), without ramping.	→	11,040 MW (all hours), 4,000 MW (5–10pm, all months) for summer PRM study, 11,040 MW before pro-rata adjustment for non-summer PRM study
RELIABILITY CALIBRATION	Targeted removal of aging thermal units - Portfolio reduced until the 0.1 LOLE target was met	→	Pro rata capacity reductions across resource types except for hydro - Portfolio reduced until the 0.1 LOLE target was met

2028 Resource Portfolio is Over-Reliable and Calibrated to Meet the 0.1 LOLE



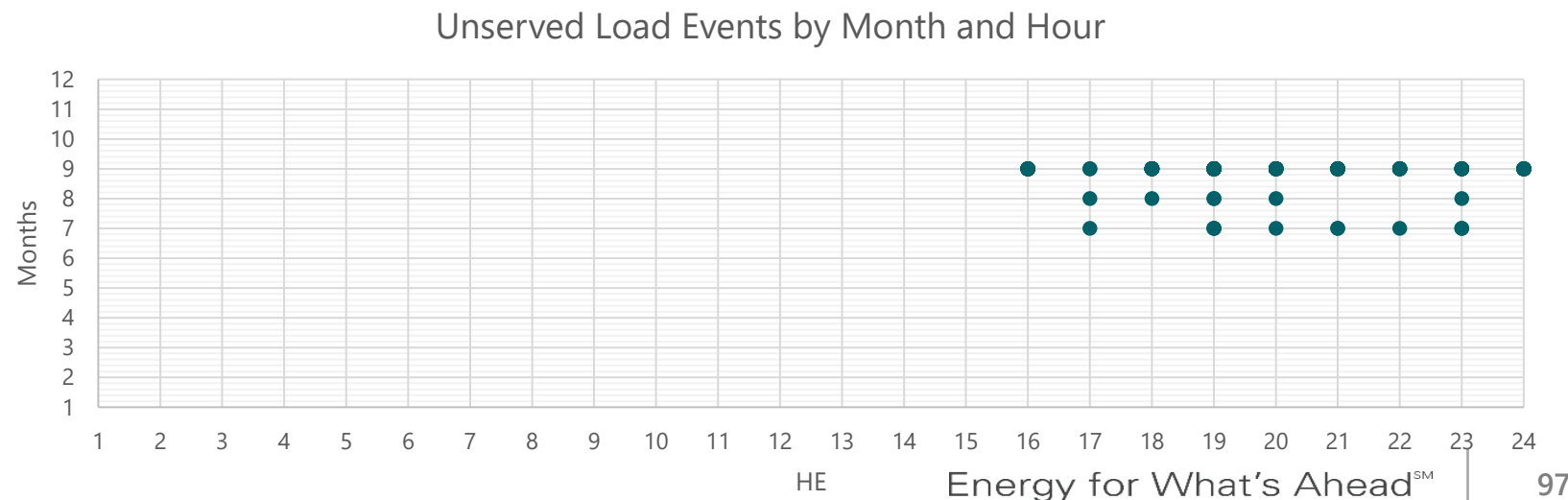
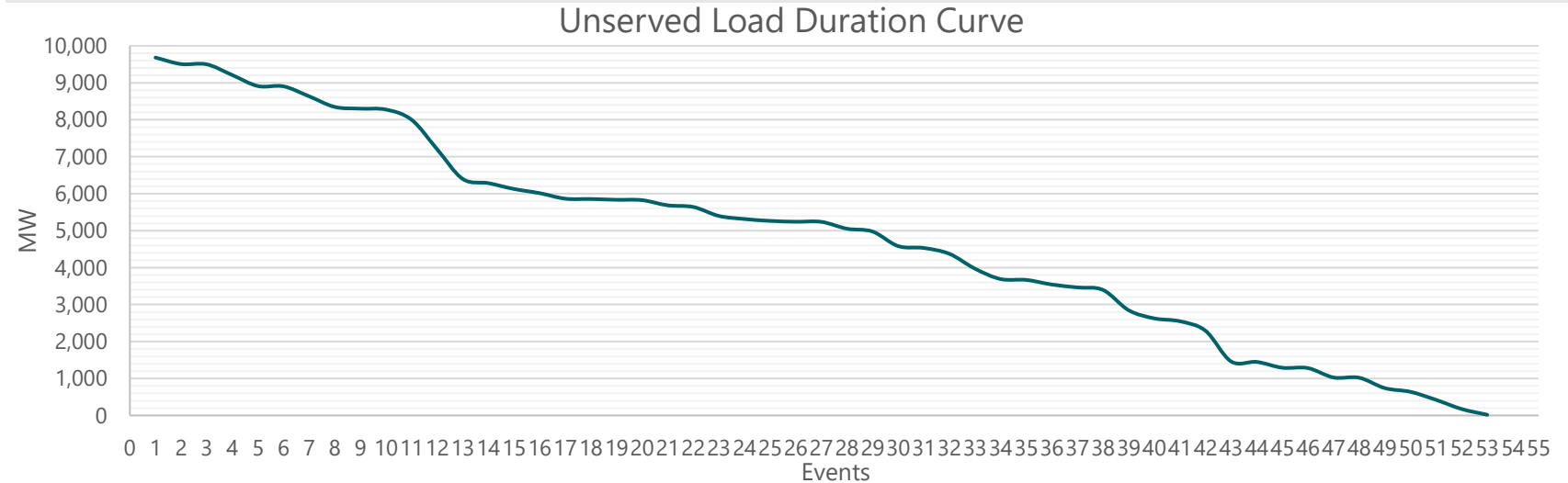
- SCE built the 2028 baseline LOLE model using the same resource assumptions as CPUC’s baseline dataset¹
- The 2028 baseline portfolio is over-reliable, with no unserved load reported (LOLE = 0)
- To calibrate to the 1-in-10 reliability target (0.1 LOLE), SCE reduced capacity across resource types rather than removing only aging thermal resources.
 - ❑ Most resource types were reduced pro rata by ~19%.
 - ❑ Hydro capacity was held constant because modeled hydrology already constrains availability.
 - ❑ Imports were reduced by 19% and excluded from the resource buildout shown.
 - ❑ Demand response was conservatively adjusted from 3,350 MW to 1,700 MW, consistent with the 2026 RA study.

SCE's 2028 LOLE Study Draft Results without Economic and Demographic Uncertainty (EDU)

Key takeaways from LOLE study results:

- **SCE's Calibrated portfolio meets the 1-in-10 reliability standard after ~21 GW of reductions across resource types.**
 - LOLE = 0.085 across all 625 simulations.
 - Events cluster in late afternoon to evening/late night hours (HE 16–24).
 - The most severe scenario has a 5 hours event on the peak summer day in September with the highest unserved load hour 9,682 MW.
 - Average unserved-load event duration across all 625 scenarios is 3 hours.

Only summer reliability risks are observed. all unserved-load hours occur in summer months (July, August, and September). Concentrated in later afternoon to evening/late night hours.



Economic and Demographic Uncertainty (EDU) Impacts

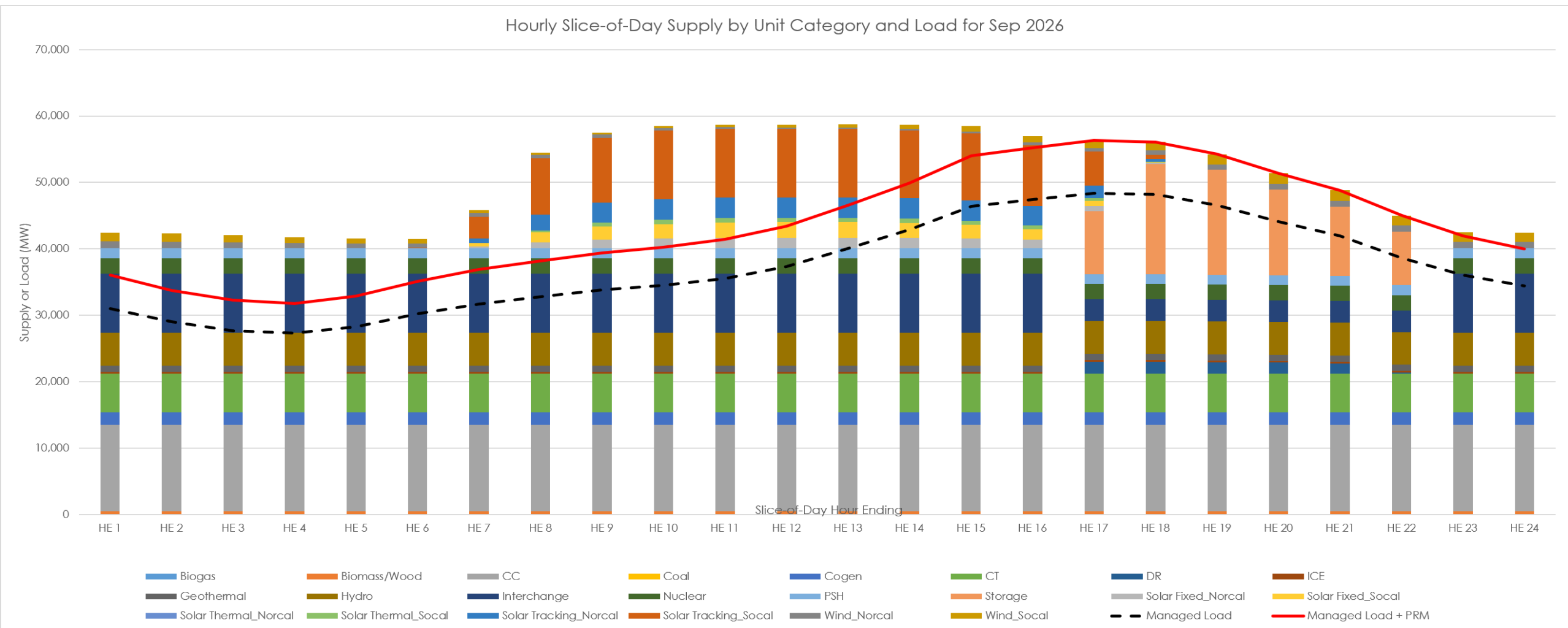
ERROR	PROBABILITY	LOLE (Event/YEAR)	
+2.00%	0.009		0.274
+1.00%	0.205		0.166
0.00%	0.573		0.085
-1.00%	0.205		0.011
-2.00%	0.009		0.000

Probability-weighted total LOLE: **0.096 event/year** — effectively meets the 1-in-10 standard of 0.1

- SCE incorporated economic and demographic uncertainty (EDU) using a 5-point probability-weighted distribution based on the 2025-2026 MISO LOLE study, modeled in PLEXOS.
- Load forecast error spans $\pm 2\%$, with 57.3% weight on the 0% base case, 20.5% on each $\pm 1\%$ case, and 0.9% on each $\pm 2\%$ case.
- Risk is concentrated in the upside load cases: LOLE reaches 0.274 at +2% and 0.166 at +1% vs. 0.085 at base, with a small contribution from the -1% case.
- **Why calibrate the 0% case to 0.085 rather than 0.1?** The 0.085 target preserves margin for economic and demographic uncertainty. Once all upside load cases are probability-weighted, total LOLE is **effectively at the 1-in-10 standard** of 0.1 event/year.

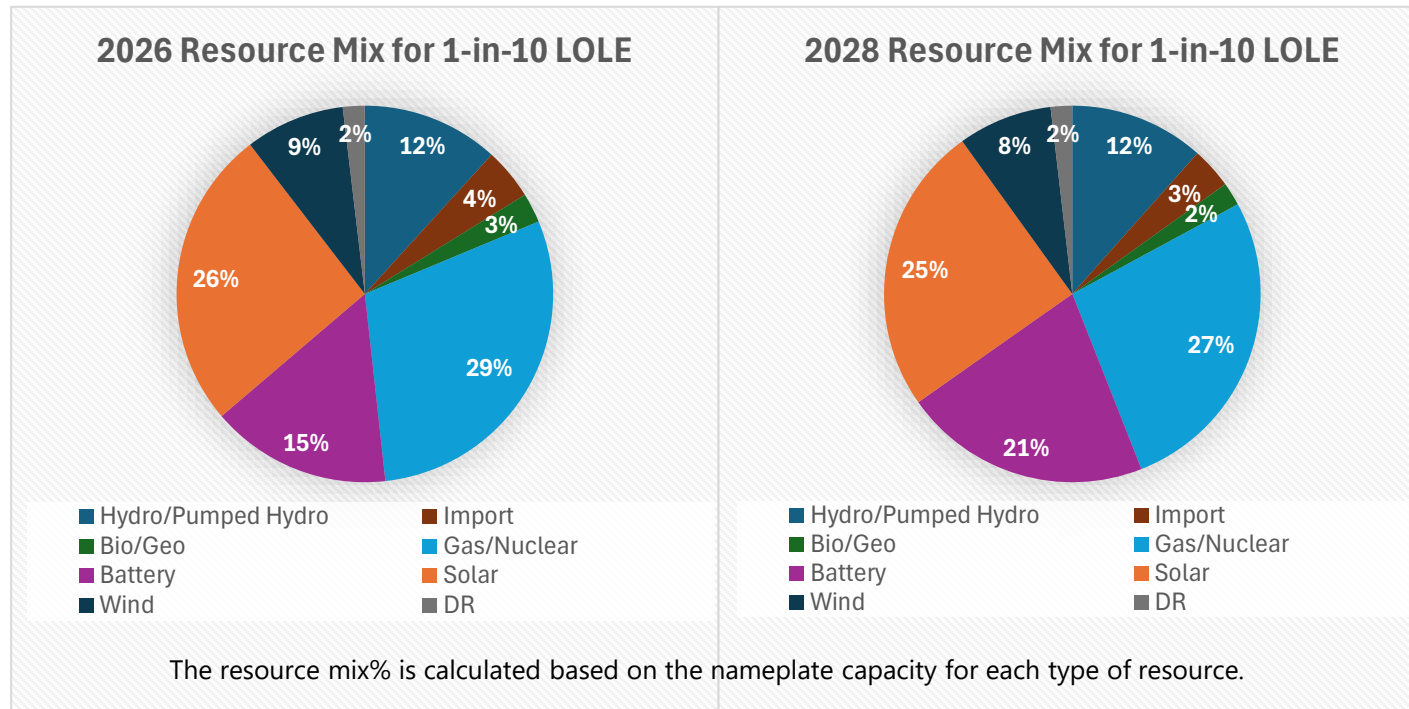
September SOD Translation Using the IEPR 1-in-2 Load Profile

Using the CPUC Slice-of-Day tool and the IEPR 1-in-2 managed-load profile, SCE's calibrated portfolio produces an implied September PRM of 16.4%, with HE 18 as the constraining hour.



Increasing the share of energy-limited resources requires a higher PRM to maintain the same LOLE target

- The system is over-reliable in both 2026 and 2028 under the reference resource portfolios without adjustment (LOLE ≈ 0).
- To calibrate the system to the 1-in-10 reliability criterion (LOLE ≈ 0.1):
 - 2026: ~5 GW of gas resources were removed.
 - 2028: Over 21 GW of a mix of non-hydro resources were removed.
- Between 2026 and 2028, substantial battery additions significantly changed the resource mix:
 - Gas/Nuclear + imports: 34% $\rightarrow$ 30%
 - Battery: 15% $\rightarrow$ 21%
- **The results are consistent with a higher PRM for a portfolio containing a larger share of energy-limited resources**, even though the system meets the same LOLE target.



2026	→	2028
Gas/Nuclear + Imports 34%	→	30%
Battery 15%	→	21%
PRM Lower (15.5%)	→	PRM Higher (16.4%)

15.5% of PRM for year 2026 and 16.4% of PRM for year 2028 were both obtained from SCE's LOLE study

Reserve Margin Sensitivity to Renewable Exceedance Profiles in SOD Tool

Solar runs too late

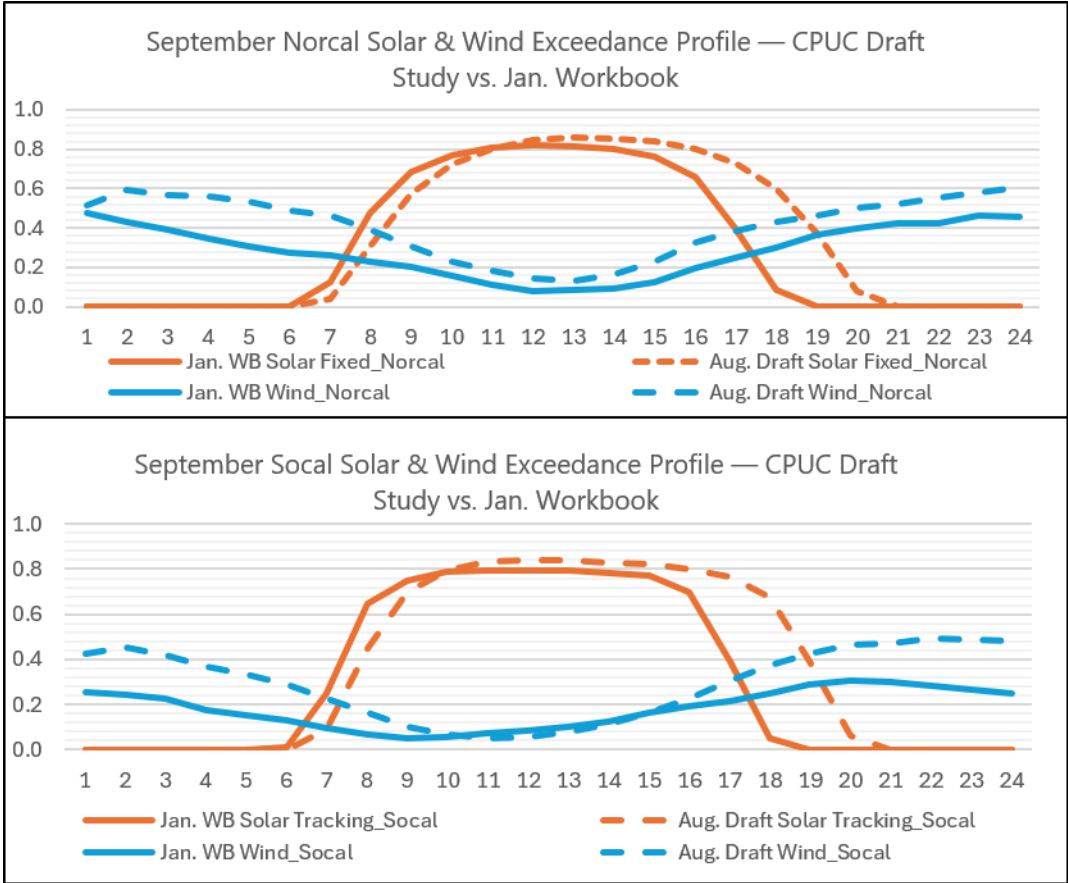
Draft Study solar still generates through HE 21. CAISO's Sept. 1, 2026 trend — a recent extreme heat day — shows solar ending by HE 19.

Wind is too strong

Draft Study wind runs higher in every hour. Actual CAISO wind is flat and low

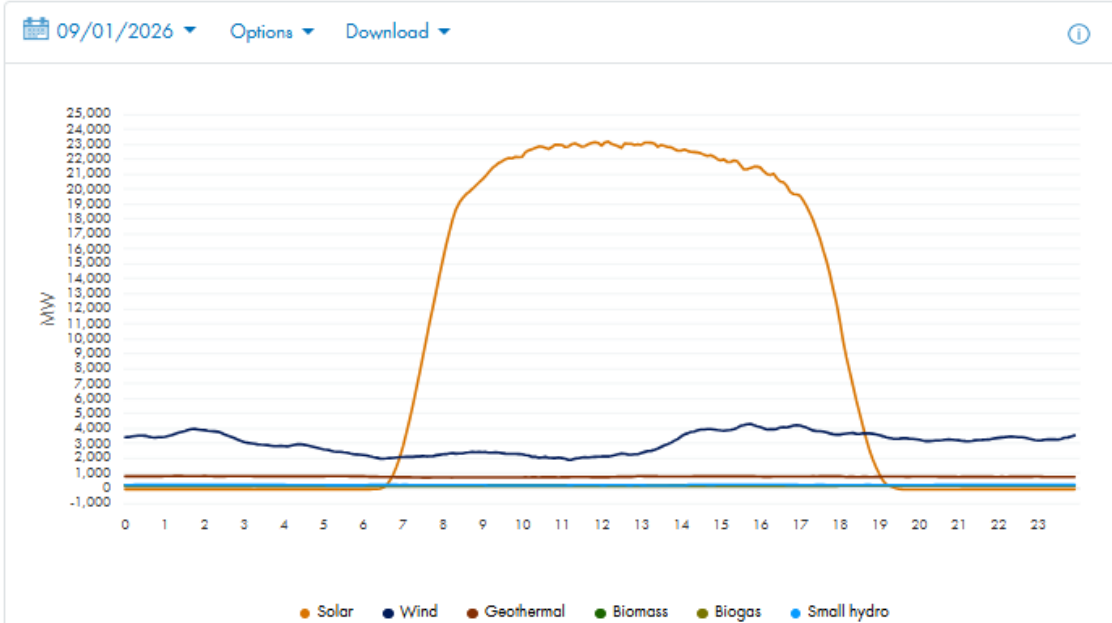
CAISO trends are the check

Observed shapes track the January 2026 Workbook, so SCE applies those profiles.



Renewables trend

Power separated by renewable resource, on a 5-minute average.



CAISO renewables trend, Sept. 1, 2026 — on a recent extreme heat day, solar output ends by HE 19 and wind stays near 2,000–4,000 MW.

SCE Seasonal PRM Study Draft Results

RESULTING SEASONAL PRM

Season	Months	PRM
Early Spring	Jan – Apr	17.4%
Spring	May – Jun	22.5%
Summer	Jul – Oct	16.4%
Winter	Nov – Dec	23.0%

WHY PRM VARIES BY SEASON

- **lower solar production outside summer increases reserve needs** - Solar production is highest during summer months and lower in spring and winter. As solar output declines, net load increases and additional reserve capacity is required to maintain the same reliability standard, resulting in higher implied PRMs in some non-summer seasons.
- **Tail weather years drive the boundary case** — Non-summer reliability risk appears in only a small number of weather years, so the boundary portfolio is determined by those extreme conditions rather than an average year.

1

Find the boundary case in PLEXOS

Reviewed against load until unserved load events no longer appear in the non-summer months.

2

Group the non-summer months

Load and boundary results define three groups: Jan–Apr, May–Jun, and Nov–Dec.

3

Align the PLEXOS model with the SOD workbook

Reconciling the stochastic production cost simulation with the SOD translates the boundary buildout into a PRM.

4

Respect seasonal patterns

Remove the 4,000 MW non-summer import constraint; use updated SOD seasonal hydro counting.

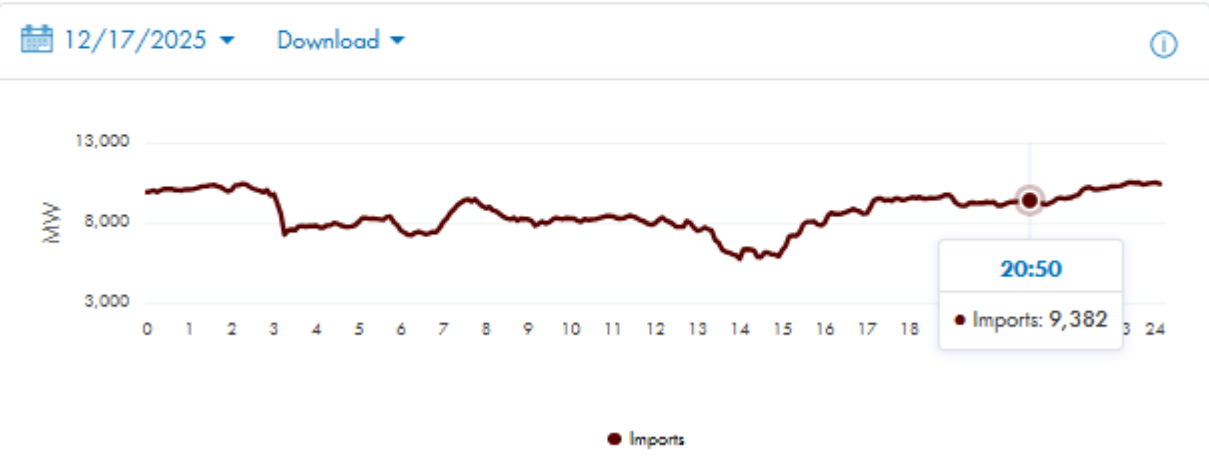
Supporting Seasonal Adjustments for Seasonal PRM Study: Imports and Hydro

Imports: removing the 4,000 MW non-summer cap

Day-ahead market outcomes show import availability in non-summer peak hours well above the constraint applied in the study.

Imports trend

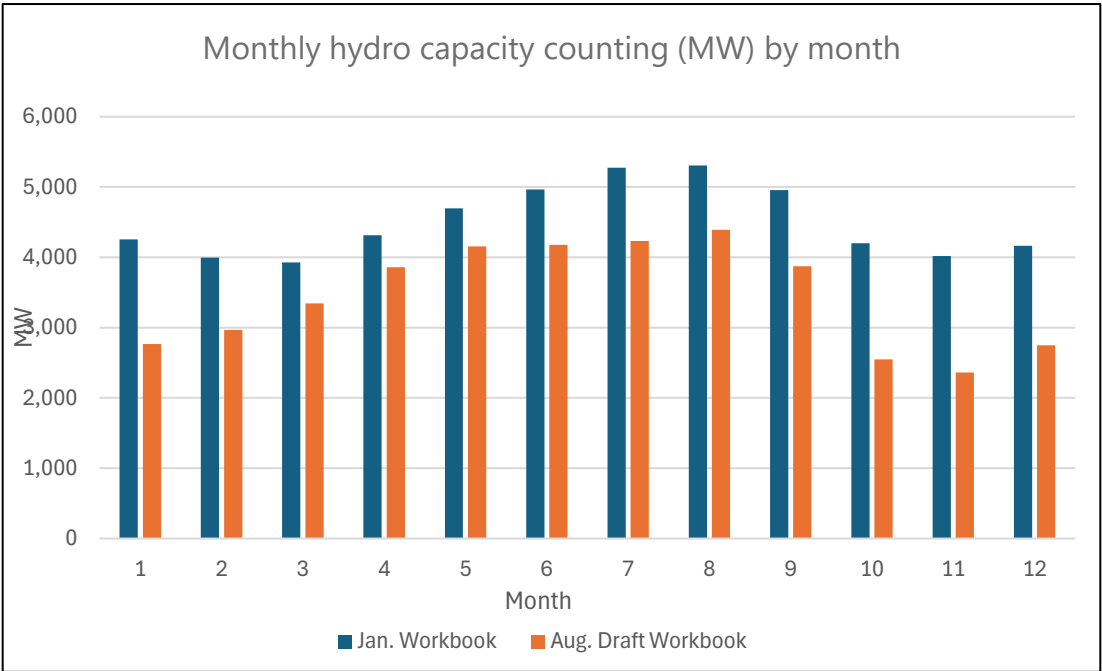
Unspecified imported power, on a 5-minute average, scheduled for delivery within the ISO balancing authority.



CAISO imports trend, Dec. 17, 2025 — imports hold near 8,000–10,000 MW across all hours, well above the 4,000 MW constraint.

Hydro: January profile vs. updated SOD counting

The January profile carried unrealistically high non-summer hydro. SCE instead uses the updated seasonal counting from the SOD workbook CPUC published with the draft study.



Monthly hydro capacity counting (MW) by month — the January 2026 Workbook sits well above the updated counting in every non-summer month.

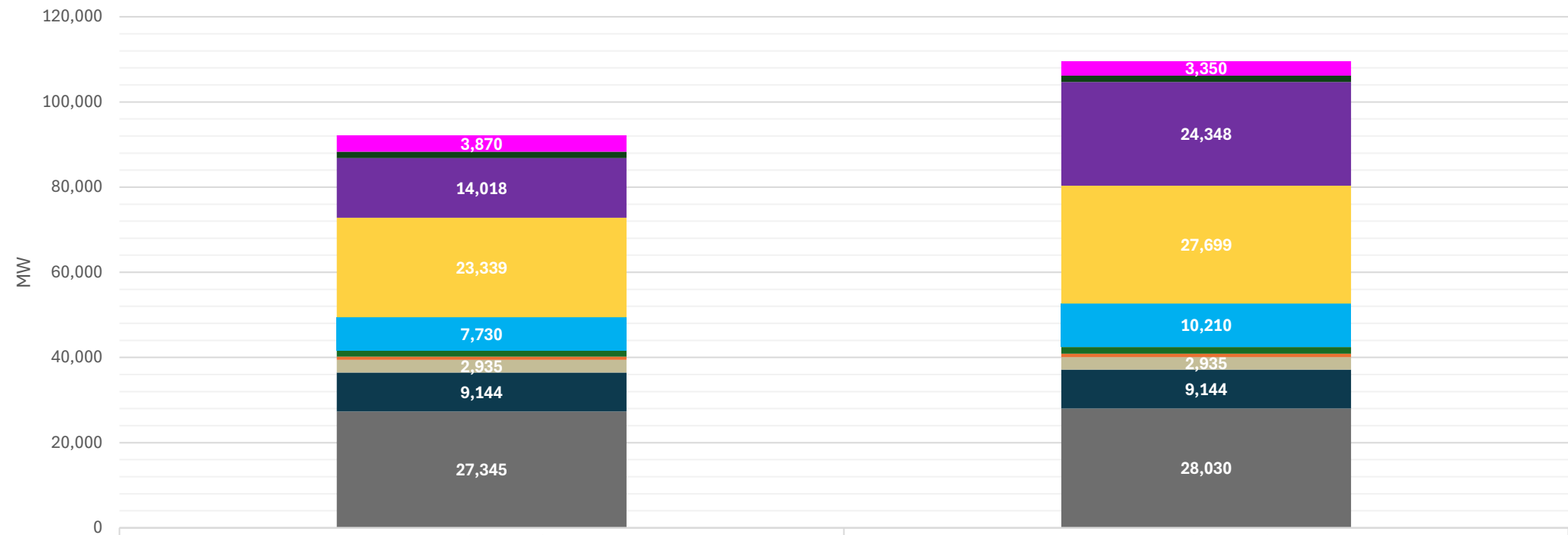
Backup

Energy for What's AheadSM



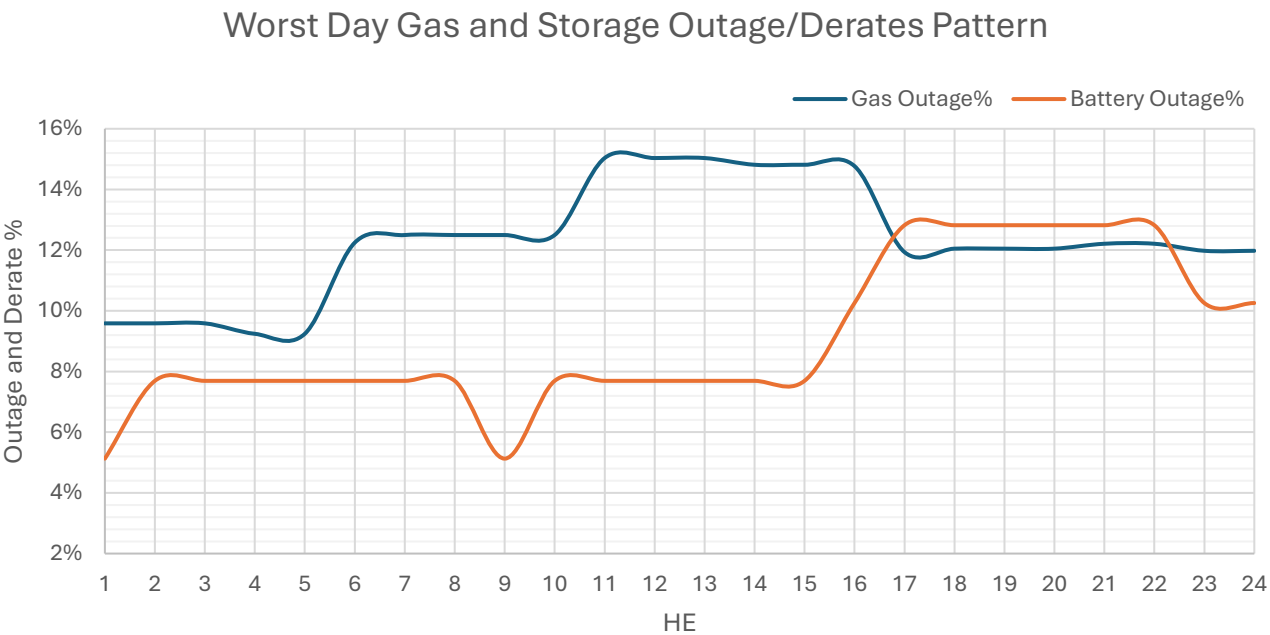
2028 RA Baseline Portfolio Adds ~17 GW of Capacity Relative to the 2026 RA Baseline

2028 Resource Baseline Capacity: 2026 RA vs. 2028 RA



	2026 RA Baseline Capacity (MW)	2028 RA Baseline Capacity (MW)
DR	3,870	3,350
PSH	1,483	1,483
Li-ion Battery	14,018	24,348
Solar	23,339	27,699
Wind	7,730	10,210
Geothermal	1,513	1,592
Bio	786	753
NUCLEAR	2,935	2,935
Hydro	9,144	9,144
CC/CT/ICE/Steam/Cogen	27,345	28,030

Battery Utilization and Resource Outages during the Worst Day



Gas and Battery Resources Outage Conditions on the Worst Day

100%

Battery and gas fully committed and utilized on the worst day

13%

Battery outage rise during HE 17-22 to 13%

12%

Gas derates due to the forced outage and the ambient derate reach as high as 15% in the afternoon and remain 12% during HE 17-22

Scenario	Battery Outage	Battery Utilization
Worst Days	Up to 12%	100%

Questions & Discussion

Group Discussion Questions

- 1) Discuss differences in Inputs and Assumptions across three studies. How do these differences impact the PRM?
 - For example, annual vs. monthly study, inclusion of econ & demo uncertainty, method for surfacing LOLE, baseline portfolio
- 2) Side-by-side comparison of headline results (surplus MW or equivalent, annual LOLE, Sept. ICAP PRM, UCAP PRM, Summer/off-peak grouping, etc.)
 - Comparison table provided on the following slides.

Comparison of Studies

Category	Energy Division	SCE	CalCCA
Annual or Monthly Study	° Base Case (Flat Load) -- annual PRM study ° Base Case (Stress Test) -- monthly PRM study ° Base Case (Prorate Capacity) -- annual PRM study	Annual LOLE study; Seasonal PRM developed from monthly calibration results.	Monthly risk-reserve curves allow calculation of monthly or annual PRM.
Calibration Method	° Flat Load and Stress Test Scenarios -- add demand ° Prorate Capacity Scenario -- pro rata reduction of capacity ° Constrain Imports Scenario -- lower simultaneous import limit	Proportional reduction of non-hydro resources and imports until approximately 0.1 LOLE is achieved. Hydro remains fixed and DR treated separately.	No calibration step. Risk-reserve curves found by systematically removing capacity from baseline.
Baseline Portfolio	2028 Baseline Generator List (published June 2026)	CPUC 2028 baseline portfolio as starting point.	Energy Division's 2028 Baseline Generator List (published June 2026) for CAISO region. External regions not explicitly modeled.
Imports	Simultaneous-import limit of 11,040 MW, with a 4,000 MW limit during 5-10 p.m. in June-September. Lower import sensitivities also evaluated.	Simultaneous-import limit of 11,040 MW, with a 4,000 MW limit during 5-10 p.m. for all months in the annual LOLE study. The 4,000 MW constraint is removed in non-summer months for seasonal PRM development.	4,000 MW imports available in all hours.
Economic & Demographic Uncertainty (EDU)	Uses a five-point probability-weighted load forecast error distribution from -2% to +2%, with probabilities based on a 2025 MISO study. Additional sensitivity performed to compare EDU used in prior 2024 study.	Uses a five-point probability-weighted load forecast error distribution from -2% to +2%, with probabilities based on a MISO study.	Uses a five-point probability-weighted load forecast error distribution from -2% to +2%, with probabilities based on a MISO study.
Weather / Renewables / Hydro	Uses 25 historical weather and hydro years (2000-2024), including updated demand, solar, wind, and hydro datasets.	Uses 25 weather years and CPUC renewable/hydro assumptions; paired weather years for load, renewables, and hydro.	25 years, 2000–2024; load, renewable, and hydro profiles paired by year.
Forced Outages	Forced-outage and ambient-temperature uncertainty are included in SERVIM and are derived from CAISO OMS data. UCAP PRM values use OMS data during availability assessment hours.	Runs 625 stochastic cases using CPUC resource-type-specific seasonal Total EFORD values. Includes weather-normalized thermal derates and storage outages.	Category-average forced outage rate (EFORD excluding Ambient due to Temperature) from Jan. 2026 UCAP PRM workbook. PLEXOS model uses equivalent average units rather than specific units.

Comparison of Studies

Results	Energy Division	SCE	CalCCA
Baseline Excess Capacity	Approximately 6,000 MW of additional demand could be served while maintaining the reliability standard.	Baseline portfolio is substantially over-reliable; no unserved load observed prior to calibration.	Not calculated. Achieved reserve margin of Baseline ranged from 33% - 86%.
NOU Added / Capacity Reduced to Calibrate to 0.1 LOLE	° Base Case (Flat Load) -- 6 GW of flat demand added ° Base Case (Stress Test) -- 4 to 20 GW of demand added to each month ° Base Case (Prorate Capacity) -- 5% reduction in capacity	Reduces approximately 21 GW of non-hydro resources to reach the reliability target.	Risk-reserve curves developed by removing 2 GW to 19 GW of capacity in 500 MW increments
PRM	Sept. workshop results: ° Base Case (Flat Load) produces a ~17% September PRM ° Base Case (Stress Test) 19% - 21% PRM. UCAP adjusted PRM (EFORd + Ambient) for Stress Test reduces PRM to 13.6% - 16.4%. ° Base Case (Prorate Capacity) produces ~28% PRM September PRM	16.4% summer (July-October) PRM. Draft seasonal PRMs: 17.4% (Jan-Apr), 22.5% (May-Jun), 16.4% (Jul-Oct), and 23.0% (Nov-Dec).	Depends on option, with PRM in Option 1 (RA costs vary by month) varying from 11.7% - 25% depending on the month.

Group Discussion Questions

- 3) What are key differences in methodologies between the three studies that may be impacting results?
- 4) Is the PRM insensitive to the choice of LOLE calibration methodology, meaning is the PRM the same regardless of the method?
- 5) Seasonal vs. Single PRM values, what are the pros and cons? What is the preferred approach?
- 6) Is it more appropriate to use the IEPR 1-in-2 managed peak or the 1-in-2 peak derived from SERVUM / PLEXOS model in the PRM Calibration Tool?
- 7) How should PRM calculations account for historically observed imports exceeding shown RA imports, especially in non-summer months and off-peak hours?
- 8) NOU / Perfect-Capacity: ED treats NOUs as increase in demand; CalCAA treats NOUs as a reduction in available supply. What is Staff's view of that difference, and can Staff show the portfolio under both conventions so parties can isolate the effect on the PRM?
- 9) How are operating reserves enforced when load is added vs. when capacity is removed? Are reserves required on NOU or added demand?
- 10) What is the appropriate operating reserve levels to apply in the reliability model? Are current assumptions consistent with NERC requirements?
- 11) Please provide a schedule for any remaining studies or sensitivities, and the form that October PRM Recommendations will use.

R.25-10-003 Track 2 Schedule

Track 2 Schedule (excluding Flexible & Local Capacity Requirement topics)	
Parties file and serve Draft 2028 LOLE studies	Aug. 14, 2026
Workshop on LOLE studies	Sept. 15, 2026
Parties file and serve Final 2028 LOLE studies and PRM proposals	Oct. 13, 2026
Opening comments on LOLE studies and PRM proposals	Nov. 12, 2026
Reply comments on LOLE studies and PRM proposals	Dec. 3, 2026
Parties file and serve Track 2 proposals (other than PRM proposals)	Jan. 15, 2027
Workshop on Track 2 proposals	Early Feb. 2027
Opening comments on Track 2 proposals (other than PRM proposals)	Feb. 26, 2027
Reply comments on Track 2 proposals (other than PRM proposals)	March 12, 2027
Proposed Decision on Track 2	June 2027



California Public Utilities Commission

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Establish
Energization Timelines.

R.24-01-018

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO
CLEAN COALITION MOTION TO SET ASIDE SUBMISSION AND REOPEN
THE RECORD REGARDING PG&E'S ANNOUNCED \$2 BILLION
REDUCTION IN 2027 CAPITAL SPENDING**

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September 24, 2026

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SUMMARY OF RECOMMENDATIONS

CalCCA recommends the Commission:

- Grant Clean Coalition’s Motion to Set Aside Submission and Reopen the Record and reopen the Phase 2 record on the limited basis requested;
- Direct PG&E to respond to Clean Coalition’s proposed questions, supplemented to address PG&E’s expected compliance with adopted energization targets, potential mitigation measures, and the causes of anticipated delays;
- Confirm that voluntary utility capital allocation decisions do not provide a basis for relaxing adopted energization targets or otherwise applicable remedial action or enforcement standards;
- Provide parties an opportunity to comment on PG&E’s supplemental response and retain the ability to seek targeted clarification or supplemental responses from PG&E, if necessary, before resubmission; and
- Use the supplemental information to inform the Phase 2 compliance and remedial action framework, including how the Commission identifies and responds to emerging risks to the achievement of adopted energization targets.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Establish
Energization Timelines.

R.24-01-018

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO
CLEAN COALITION MOTION TO SET ASIDE SUBMISSION AND REOPEN
THE RECORD REGARDING PG&E'S ANNOUNCED \$2 BILLION
REDUCTION IN 2027 CAPITAL SPENDING**

Pursuant to Rule 11.1(e) of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,¹ the California Community Choice Association² (CalCCA) submits this response to the *Clean Coalition Motion to Set Aside Submission and Reopen the Record Regarding PG&E's Announced \$2 Billion Reduction in 2027 Capital Spending*³ (Motion), dated September 9, 2026.

I. INTRODUCTION

Clean Coalition's Motion identifies material information concerning Pacific Gas and Electric Company's (PG&E) plans for capital spending that arose after the Phase 2 record was

¹ *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021), <https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf>, as amended by Resolution ALJ-485 (June 11, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M609/K277/609277261.PDF>.

² California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, Valley Clean Energy, and WestLight Energy.

³ *Clean Coalition Motion to Set Aside Submission and Reopen the Record Regarding PG&E's Announced \$2 Billion Reduction in 2027 Capital Spending*, Rulemaking (R.) 24-01-018 (Sept. 9, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M618/K439/618439586.PDF>.

submitted. This information potentially bears directly on the Commission’s consideration of energization timeline compliance, remedial actions, monitoring, and enforcement.⁴ CalCCA supports Clean Coalition’s request that the Commission reopen the record on a limited basis and direct PG&E to provide the requested information.

On September 2, 2026, PG&E announced plans to defer approximately \$2 billion in planned investment for 2027, reducing planned 2027 capital expenditures from \$13.4 billion to \$11.4 billion.⁵ PG&E stated that it has identified work that can be delayed or deferred while maintaining critical safety investments and current performance on compliance obligations.⁶ PG&E’s Post-Legislative Session Update Conference Call specifically identified connecting new housing projects among the work that will be delayed or deferred. PG&E Chief Executive Officer Patti Poppe stated that the reduction “will push dates out,” while acknowledging that PG&E had not yet finalized the specific work affected.⁷

These developments warrant the limited additional record development Clean Coalition requests. They do not establish that PG&E will fail to meet an adopted energization target, nor is such a determination necessary to grant the Motion. Rather, the announcement raises material questions regarding whether PG&E continues to expect to achieve the Commission’s adopted energization targets and, if those targets may be at risk, what steps may be necessary to avoid

⁴ Motion, at 1-3.

⁵ PG&E, *PG&E Launches Strategic Review to Build a Better, More Affordable Energy Future for California Customers* (Sept. 2, 2026) (PG&E Press Release), <https://investor.pgecorp.com/news-events/press-releases/press-release-details/2026/PGE-Launches-Strategic-Review-to-Build-a-Better-More-Affordable-Energy-Future-for-California-Customers/default.aspx>.

⁶ *Ibid.*

⁷ PG&E, *Post Legislative Session Update* (Sept. 2, 2026), Slide 4, https://s21.q4cdn.com/673114418/files/content_files/PG-E-Post-Legislative-Session-Update-2026.pdf; *PG&E Corporation Post-Legislative Session Update Conference Call* (Sept. 2, 2026), <https://stockanalysis.com/stocks/pgc/transcripts/742515-status-update/>.

future noncompliance. These are the same types of compliance, monitoring, and remedial action questions presently before the Commission in Phase 2.⁸

In support of the Motion, CalCCA addresses four principal issues. *First*, PG&E's announcement warrants limited additional record development because the existing record does not provide sufficient information to evaluate its potential effect on adopted energization targets. *Second*, obtaining this information before deadlines are missed is consistent with CalCCA's Phase 2 recommendations for timely identification of emerging compliance risks and effective remedial action. PG&E's voluntary capital allocation decisions should not provide a basis for relaxing otherwise applicable standards. *Third*, CalCCA supports Clean Coalition's proposed questions for PG&E and identifies limited additional information from PG&E that will assist the Commission's review. *Fourth*, CalCCA supports a narrow procedural process that allows party comment and targeted Commission follow-up, if necessary, without unduly delaying resolution of Phase 2.

CalCCA recommends the Commission:

- Grant Clean Coalition's Motion and reopen the Phase 2 record on the limited basis requested;
- Direct PG&E to respond to Clean Coalition's proposed questions, supplemented to address PG&E's expected compliance with adopted energization targets, potential mitigation measures, and the causes of anticipated delays;
- Confirm that voluntary utility capital allocation decisions do not provide a basis for relaxing adopted energization targets or otherwise applicable remedial action or enforcement standards;
- Provide parties an opportunity to comment on PG&E's supplemental response and retain the ability to seek targeted clarification or supplemental responses from PG&E, if necessary, before resubmission; and

⁸ *Assigned Commissioner's Amended Phase 2 Scoping Memo and Ruling*, R.24-01-018 (Mar. 19, 2026) (Amended Scoping Ruling), at 2–4, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K999/602999018.PDF>.

- Use the supplemental information to inform the Phase 2 compliance and remedial action framework, including how the Commission identifies and responds to emerging risks to the achievement of adopted energization targets.

II. PG&E’S ANNOUNCEMENT WARRANTS LIMITED ADDITIONAL RECORD DEVELOPMENT

The Commission should grant the Motion because PG&E’s announcement raises questions directly within the Phase 2 scope that cannot be answered on the existing record. Specifically, the Commission does not yet have sufficient information to determine which energization work will be affected, whether PG&E continues to expect to meet the adopted energization targets, or whether additional monitoring or remedial action may be necessary.

The Amended Scoping Ruling asks how the Commission should determine when remedial action is necessary to achieve energization targets, what remedial actions should be ordered, how compliance should be monitored, and how the Commission should establish an enforcement policy pursuant to Public Utilities Code section 934(g).^{9, 10} PG&E’s announcement that certain work will be delayed or deferred, including work connecting new housing projects, bears directly on these questions.

The existing information, however, does not establish the extent of any effect on PG&E’s energization obligations. As Clean Coalition identifies, PG&E has not: (1) quantified the portion of the \$2 billion reduction attributable to energization work; (2) identified the number or categories of customer energizations that will be affected; (3) identified the anticipated duration of delays; or (4) explained whether the affected work is subject to the timelines established in Decision (D.) 24-

⁹ Amended Scoping Ruling, at 2–4.

¹⁰ All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

09-020.^{11, 12} These unanswered questions prevent the Commission from determining whether and to what extent PG&E’s announcement creates a risk to achieving the adopted energization targets.

Additional information is particularly appropriate given PG&E’s prior representations regarding the relationship between energization funding and performance. When seeking increased energization cost caps in this proceeding, PG&E stated that additional funding would allow it to “comply with Assembly Bill (AB) 50, and meet Energization OIR targets by 2027,” and explained that available funding directly affects the completion and timing of energization work.¹³

The Commission should have sufficient information to understand whether PG&E’s newly announced capital reduction changes those prior expectations or affects work underlying prior energization funding requests or authorizations.

The appropriate response is additional record development, not a presumption regarding the ultimate effect of PG&E’s announcement. A targeted response from PG&E would allow the Commission to determine whether adopted energization targets are at risk and, if so, whether additional monitoring or remedial action is warranted.

III. COMMISSION REVIEW SHOULD OCCUR BEFORE ENERGIZATION DEADLINES ARE MISSED, AND VOLUNTARY CAPITAL ALLOCATION DECISIONS SHOULD NOT RELAX REMEDIAL ACTION STANDARDS

Obtaining this information now is consistent with, rather than a departure from, the compliance framework CalCCA proposed in its Phase 2 Opening Comments. CalCCA recommended objective triggers for remedial action tied principally to utility performance, along

¹¹ Motion, at 8.

¹² D.24-09-020, *Decision Establishing Target Energization Time Periods and Procedure for Customers to Report Energization Delays*, R.24-01-018 (Sept. 12, 2024), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M540/K806/540806654.PDF>.

¹³ *PG&E Request to Revise the 2025 and 2026 Energization Cost Caps Rebuttal Testimony* (Dec. 13, 2024), R.24-01-018 (PG&E Request), at 2, 10.

with frequent reporting to identify emerging compliance risks.¹⁴ The Commission can investigate a known risk to future compliance without prematurely determining whether PG&E has missed a target or that remedial action is presently required.

In its Phase 2 Opening Comments, CalCCA explained that the Commission should ensure its energization requirements are enforceable, transparent, and effective in practice. CalCCA recommended clear triggers for remedial action tied to missed energization targets, a structured escalation framework for noncompliance, and frequent, standardized, and transparent reporting to enable ongoing oversight.¹⁵

Section 934(d) requires the Commission to require electrical corporations to take remedial actions necessary to achieve the adopted energization targets. This statutory direction supports a framework that ensures the targets are achieved, rather than merely responding after persistent noncompliance. CalCCA therefore proposed clear and objective triggers for remedial action, including missed average or maximum targets, overdue projects, systemic delays, disparate customer impacts, and incomplete or missing data.¹⁶

CalCCA's proposal also recognized the need for information that allows the Commission to identify problems as they develop. CalCCA recommended enhanced monthly reporting to provide a "current and actionable view of performance" and "ensure timely identification of emerging compliance risks."¹⁷ Waiting until the effects of PG&E's capital reduction are reflected solely in future performance reports could leave the Commission evaluating those effects only after customer delays have occurred.

¹⁴ *California Community Choice Association Opening Comments on Assigned Commissioner's Amended Phase 2 Scoping Memo and Ruling*, R.24-01-018 (Apr. 30, 2026) (CalCCA Phase 2 Opening Comments), at ii, 1–5, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M605/K875/605875479.PDF>.

¹⁵ *Ibid.*

¹⁶ CalCCA Phase 2 Opening Comments, at 2–5.

¹⁷ *Id.* at 4.

The Commission should also make clear that a utility's voluntary capital allocation decisions do not provide a basis for relaxing adopted energization targets or otherwise applicable standards for remedial action. PG&E previously represented that additional funding would allow it to comply with AB 50¹⁸ and meet this proceeding's energization targets by 2027, and that available funding directly affects the completion and timing of energization work.¹⁹ PG&E has now announced its decision to defer approximately \$2 billion in planned 2027 investment, identifying customer energization work as one of the categories that may be delayed or deferred.²⁰ If that decision contributes to PG&E's failure to achieve an adopted energization target, PG&E should remain subject to the same remedial action and enforcement framework that would otherwise apply. A utility should not receive leniency from an adopted performance requirement based on the consequences of a capital allocation decision within its own control.

This conclusion is also consistent with PG&E's prior position that it would not refuse to spend beyond an energization cost cap if necessary to meet the targets adopted in D.24-09-020.²¹ The Commission should distinguish between circumstances outside an investor-owned utility's (IOU) control and delays resulting from the IOU's own management, resource allocation, or investment decisions. That distinction preserves the Commission's ability to consider legitimate external constraints without creating an incentive for a utility to reduce the resources devoted to energization and subsequently rely on that reduction to justify diminished performance.

PG&E's announcement illustrates why the Phase 2 framework should address potential compliance risks before deadlines are missed. The Commission need not determine today that

¹⁸ Assembly Bill 50 (Wood, Ch. 317, Stats. 2023), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240AB50.

¹⁹ PG&E Request, at 2, 10.

²⁰ PG&E Press Release.

²¹ *PG&E Response to TURN Data Request TURN_008-Q001* (Jan. 9, 2025), at 1, <https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2401018/7942/553678982.pdf>.

remedial action is warranted. It should, however, have the information necessary to determine whether PG&E continues to expect to meet the adopted targets, what risks the announced reduction presents, what portion of those risks results from circumstances within PG&E's control, and whether prospective action is necessary to avoid future noncompliance.

IV. CLEAN COALITION'S PROPOSED QUESTIONS SHOULD BE ADOPTED AND SUPPLEMENTED

Clean Coalition's proposed questions²² provide an appropriate starting point because they seek the information necessary to determine the scope and consequences of PG&E's announcement without presuming noncompliance. CalCCA supports those questions and recommends limited additions directed at three issues: (1) expected compliance; (2) mitigation; and (3) causation.

First, expected compliance. PG&E should expressly state whether it currently expects to meet each applicable energization target adopted in D.24-09-020, notwithstanding the announced capital reduction. If PG&E does not expect to meet a target, it should identify the affected target, anticipated magnitude and duration of the impact, and affected categories of projects or customers. Clean Coalition's proposed Question 4 asks whether and how the reduction is anticipated to affect PG&E's ability to achieve the average and maximum energization timelines.²³ This supplemental question would further clarify PG&E's present expectation regarding compliance with each applicable target.

Second, mitigation. PG&E should identify the mitigation or remedial measures it has considered or intends to implement to avoid or minimize impacts on energization timelines. This should include any reprioritization of work, reallocation of available funding, staffing, or

²² Motion, Appendix A, at A-1–A-3.

²³ Motion, Appendix A, at A-2, Question 4.

contracting changes, or other operational measures. This information would assist the Commission in determining not only whether a compliance risk exists, but also what actions may be available to address that risk before an adopted target is missed.

Third, causation. PG&E should identify the extent to which any anticipated energization delays are attributable to the announced capital allocation decision versus other circumstances outside PG&E's control. This distinction is important not only for understanding the effects of PG&E's announcement but also for determining the appropriate application of the Phase 2 remedial action framework. To the extent a future failure to achieve an adopted target results from PG&E's voluntary capital allocation decisions, those decisions should not provide a basis for relaxing otherwise applicable remedial action or enforcement standards.

The Commission should also consider clarifying Clean Coalition's proposed Question 3 by requiring PG&E to identify how customer and project impacts will factor into its determination of which projects to delay or defer. Clean Coalition already proposes requiring PG&E to explain the criteria and process used to select affected work, the schedule for those determinations, and the process for notifying the Commission and parties.²⁴ Identifying how customer impacts factor into those criteria would provide additional context regarding the consequences of PG&E's implementation decisions.

V. LIMITED REOPENING WILL SUPPORT TIMELY OVERSIGHT WITHOUT UNDULY DELAYING PHASE 2

The Commission can obtain this additional information without broadly reopening Phase 2 or materially delaying the proceeding. Clean Coalition proposes a targeted PG&E response followed by a brief opportunity for party comments and prompt resubmission. CalCCA supports that approach with one additional procedural safeguard: the Commission should retain the ability

²⁴ Motion, Appendix A, at A-2, Question 3.

to seek targeted follow-up if PG&E's response or subsequent party comments identify material questions requiring clarification.

Clean Coalition proposes that PG&E provide its supplemental response within ten calendar days, followed by a seven-day opportunity for parties to comment. Its proposed ruling does not require an evidentiary hearing at this time and provides that the proceeding would thereafter stand resubmitted unless otherwise ordered.²⁵ This narrow process appropriately focuses the additional record development on the September 2 developments rather than reopening Phase 2 generally.

CalCCA recommends that the Commission preserve the Administrative Law Judge's ability to require targeted clarification or supplemental responses from PG&E after party comments if PG&E's initial response or the comments reveal material factual gaps. This need not create an additional mandatory round of briefing. Rather, it would provide a limited mechanism to ensure that the reopened record answers the questions for which it was reopened before the proceeding is resubmitted.

More broadly, the present circumstances reinforce the importance of timely visibility into changes that may affect energization performance. As Clean Coalition explains, section 933.5 requires utility reporting regarding constraints and obstacles to timely energization, including funding limitations, while section 934(e) requires periodic updates to energization timelines and reporting requirements to reflect changed circumstances, new information, and experience.²⁶ CalCCA's Phase 2 Opening Comments similarly recommended frequent and transparent reporting to permit ongoing oversight and timely identification of emerging compliance risks.²⁷

²⁵ Motion, at 9; Appendix A at A-3.

²⁶ Motion, at 8.

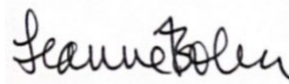
²⁷ CalCCA Phase 2 Opening Comments, at ii, 4.

The information developed through this limited reopening can serve two related purposes. It will provide the Commission with the information necessary to evaluate the potential energization impacts of PG&E's September 2, 2026, announcement, and it can inform the Commission's development of a Phase 2 framework capable of identifying and responding to similar material risks to achievement of energization targets as they arise.

VI. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of this response and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

A handwritten signature in black ink, appearing to read "Leanne Bober", is centered below the "Respectfully submitted," text.

Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

September 24, 2026

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Modernize
the Electric Grid for a High Distributed
Energy Resource Future.

R.21-06-017

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO CENTER
FOR BIOLOGICAL DIVERSITY UTILITY CONSUMER'S ACTION NETWORK
MOTION TO ADDRESS UNADDRESSED ISSUES**

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September 25, 2026

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SUMMARY OF RECOMMENDATIONS¹

CalCCA supports the Motion and recommends that the Commission:

- Identify unresolved issues and implementation details concerning the inherent IOU conflict of interest between grid investments and over demand-flexibility solutions scoped into this proceeding through an additional Track 2 phase of this proceeding, a stakeholder working group process, or a successor proceeding with a defined process and timeline; and
- Prior to closing this proceeding, establish enforceable governance principles and market-power safeguards to address the IOU conflict of interest, or provide a framework and timeline for resolving these issues.

¹ Acronyms used herein are defined in the body of this document.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Modernize
the Electric Grid for a High Distributed
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R.21-06-017

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO CENTER
FOR BIOLOGICAL DIVERSITY UTILITY CONSUMER'S ACTION NETWORK
MOTION TO ADDRESS UNADDRESSED ISSUES**

Pursuant to Rule 11.1(e) of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,² the California Community Choice Association³ (CalCCA) submits this response in support of the *Center for Biological Diversity Utility Consumer's Action Network Motion to Address Unaddressed Issues*⁴ (Motion), dated September 10, 2026.

I. INTRODUCTION

The Motion, filed by the Center for Biological Diversity (CBD) and the Utility Consumers' Action Network (UCAN), requests that the Commission address the investor-owned

² *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021), <https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf>, as amended by *Resolution ALJ-485* (June 11, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M609/K277/609277261.PDF>.

³ California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, Valley Clean Energy, and WestLight Energy.

⁴ *Center for Biological Diversity Utility Consumer's Action Network Motion to Address Unaddressed Issues*, Rulemaking (R.) 21-06-017 (Sept. 10, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M617/K649/617649890.PDF>.

utilities’ (IOU) inherent bias towards investing in capital infrastructure rather than procuring demand flexibility services from non-IOU-owned distributed energy resources (DER). CBD and UCAN request that the Commission: (1) extend Track 2 of the proceeding; (2) open a new phase of the proceeding; or (3) initiate a successor proceeding.⁵ The Motion requests that the Commission determine whether the conflict of interest inherent in the current IOU cost-recovery and investment structures impairs the cost-effective orchestration of high levels of DERs, including resources owned or managed by third parties.⁶ If the Commission makes such a determination, the Motion requests that it identify appropriate safeguards to address this conflict of interest and to do so prior to authorizing the IOUs to submit applications or proposals for DER orchestration frameworks.⁷

As the Motion explains, the Order Instituting Rulemaking (OIR) and the 2021 Scoping Memo identify, and expressly placed within the proceeding’s scope, the IOUs’ conflict of interest in achieving a high-DER future.⁸ The OIR highlights the IOUs’ focus on large capital investments and identifies the potential for a high-DER-penetration structure to negatively impact IOU rates of return.⁹ The Amended Scoping Memo assumes that the IOUs will serve as Distribution System Operators (DSO), discusses the need to “limit market power,” and asks what “gaps and barriers” exist.¹⁰ However, it fails to resolve, discuss, or state when the Commission

⁵ Motion, at 1.

⁶ *Ibid.*

⁷ *Ibid.*

⁸ See *OIR to Modernize the Electric Grid for a High DER Future*, R.21-06-017 (July 2, 2021), at 10-12, <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF>; see also *Assigned Commissioner’s Scoping Memo and Ruling*, R.21-06-017 (Nov. 15, 2021) (2021 Scoping Memo), at 6, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M422/K949/422949772.PDF>.

⁹ OIR, at 11.

¹⁰ See *Assigned Commissioner’s Amended Scoping Memo and Ruling* (Amended Scoping Memo), R.21-06-017 (Aug. 11, 2023), at 6-7, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M516/K786/516786462.PDF>.

will resolve the previously identified conflict-of-interest concerns raised in the OIR or the 2021 Scoping Memo. These issues still exist and must be considered, especially under an IOU-led DSO framework as envisioned in the Amended Scoping Memo.

Failing to address scoped issues in a proceeding violates Public Utilities Code¹¹ sections 1701.1 and 1701.5, requiring the Commission to issue a Scoping Memo describing the issues to be addressed, and to resolve those issues within the timeframe set forth in the Scoping Memo. The IOUs' incentive to prioritize grid investments over demand-flexibility solutions creates a conflict of interest that will materially affect DER participation in, and the success of, any DER orchestration framework without sufficient safeguards. Yet these concerns were left unaddressed in the Amended Scoping Memo. The Commission recently extended the statutory deadline for the proceeding to December 31, 2026, and signaled that it may close the proceeding after a Track 2 decision, potentially without resolving the scoped conflict-of-interest issues.¹² The Commission should establish a clear process and timeline for resolving these scoped issues before closing the proceeding or authorizing an IOU-led DER orchestration framework.

CalCCA supports the Motion and recommends that the Commission:

- Identify unresolved issues and implementation details concerning the inherent IOU conflict of interest between grid investments and over demand-flexibility solutions scoped into this proceeding through an additional Track 2 phase of this proceeding, a stakeholder working group process, or a successor proceeding with a defined process and timeline; and
- Prior to closing this proceeding, establish enforceable governance principles and market-power safeguards to address the IOU conflict of interest, or provide a framework and timeline for resolving these issues.

¹¹ All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

¹² See, Decision (D.) 26-09-058, *Order Extending Statutory Deadline*, R.21-06-017 (Sept. 22, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M620/K533/620533492.PDF>.

II. FAILURE TO RESOLVE SCOPED ISSUES ON THE IOU CONFLICT OF INTEREST CONCERNING GRID INVESTMENTS VERSUS DEMAND FLEX SOLUTIONS VIOLATES SECTIONS 1701.1 AND 1701.5

The Commission must address unresolved issues and implementation details regarding the scoped issue of the IOU conflict of interest between grid investments and demand flexibility solutions. These issues can be addressed by the Commission through a dedicated Track 2 phase of this proceeding, a stakeholder working group process, or a successor proceeding with a defined process and timeline.

Section 1701.5 requires the Commission to “issue by order or ruling a scoping memo that describes the issues to be considered and the applicable timetable for resolution” Section 1701.5 states that the Commission “shall resolve the issues raised in the scoping memo within 18 months of the date the proceeding is initiated” If the Commission is unable to meet that deadline, section 1701.5 requires it to “make[] a written determination that the deadline cannot be met, including findings as to the reason, and issue[] an order extending the deadline.”

As noted in caselaw interpreting these scoping memo requirements, “[i]dentifying the issues under consideration facilitates informed participation—including presentation of arguments and evidence—by those who may have a stake in the resolution of those issues.”¹³ The court went on to state that “[i]f the Commission cannot fairly be said to have complied with the statutory scoping memo requirement, it has failed to regularly pursue its authority.”¹⁴ Accordingly, the Commission cannot simply ignore issues that have been scoped into the proceeding.¹⁵

¹³ *Golden State Water Co. v. Public Utils. Comm’n* (2024) 15 Cal.5th 380, 394-395.

¹⁴ *Ibid.*

¹⁵ *See Southern California Edison Co. v. Pub. Utils. Comm’n* (2006) 140 Cal.App.4th 1085, at 1106-07 (Commission’s failure to comply with its scoping memo constitutes reversible error if the failure to do so was prejudicial); *see also Bullseye Telecom, Inc. v. California Pub. Utils. Comm’n* (2021) 66 Cal.App.5th 301, 324 (even if the Commission deviates from the Scoping Memo, petitioner must show that the deviation was significant or that it was prejudiced by it).

The OIR recognized that existing cost-recovery structures focus on large capital investment and that increased DER deployment could reduce IOU rates of return.¹⁶ The OIR further recognized that, “[f]or an IOU-administered DSO to be successful, performance incentives not tied to capital investments may be needed, or there may be a need for a third-party DSO administrator.”¹⁷

The 2021 Scoping Memo placed this issue at the center of Track 2 by directing consideration of alternative DSO models and limits on market power:

How do alternative DSO models compare in their ability to plan and operate a high DER grid, unlock economic opportunities for DERs to provide grid services, limit market power, reduce ratepayer costs, increase equity, support grid resiliency, and meet State policy objectives?¹⁸

The 2021 Scoping Memo also asked whether the IOUs should be “incentivized to cost-effectively prepare for widespread DER deployments.”¹⁹ The Amended Scoping Memo narrowed Track 2 by presuming that the IOUs would serve as DSOs, while keeping limits on IOU market power within the scope of the proceeding.²⁰ It also included in the scope of the proceeding the gaps, barriers, and solutions to meet the operational requirements for operating the grid with high DER penetration, while omitting the investigation of alternative DSO models and IOU incentives for cost-effectively integrating DERs.²¹

IOUs own and operate the distribution infrastructure on which they earn a rate of return. Under an IOU-led DSO model, the IOUs would determine distribution system needs at specific locations on the grid, control critical system information, and may administer or participate in

¹⁶ OIR, at 11.

¹⁷ *Id.* at 11-12.

¹⁸ 2021 Scoping Memo, at 6.

¹⁹ *Ibid.*

²⁰ Amended Scoping Memo, at 6.

²¹ *Ibid.*

programs, markets, or other mechanisms through which DERs compete with traditional utility investment. The existing IOU business model not only creates an inherent bias for the IOUs to prioritize grid investments over demand flexibility but also gives them a significant market advantage over third-party-owned demand flexibility providers, which lack visibility into grid needs, capabilities, and costs.

The OIR identified concerns regarding the IOU conflict of interest and market power and correctly scoped them into the proceeding. The 2021 Scoping Memo reinforced the importance of addressing these concerns by calling for an evaluation of alternative DSO business models. While the Amended Scoping Memo recognized the market power issue, it assigned the IOUs the role of DSOs without adequately addressing conflicts of interest or market power issues. By designating the IOUs as DSOs without resolving these concerns, the Commission failed to address (i) the need for protection against IOUs exerting market power; (ii) the need for guardrails to ensure competitive neutrality; or (iii) the evaluation of mechanisms to maximize DER participation. Designating the IOUs to perform the DSO function as the starting point for determining a DER orchestration framework makes resolving these questions more, not less, important.

The Commission should not close this proceeding before identifying and resolving outstanding governance and market power issues scoped into the OIR, as required by sections 1701.1 and 1701.5. The Commission should instead address these issues through a dedicated Track 2 phase of this proceeding, a stakeholder working group process, or a successor proceeding with a defined process and timeline.

III. ENFORCEABLE GOVERNANCE PRINCIPLES AND MARKET-POWER SAFEGUARDS SHOULD BE ESTABLISHED BEFORE THE COMMISSION AUTHORIZES THE IOUS TO ORCHESTRATE DERS

The Commission should establish enforceable governance principles and market-power safeguards prior to approving exclusive IOU authority to administer DER orchestration or

authorizing cost recovery for any IOU DER orchestration-related expenses and prior to closing the proceeding. Alternatively, the Commission should provide a framework and timeline for resolving these issues, either through a dedicated Track 2 phase, a stakeholder working group process, or a successor proceeding.

Clear governance structures and market-power safeguards will encourage participation in the DER orchestration framework, which is necessary for maximizing ratepayer and grid benefits by deferring or avoiding grid investments and optimizing existing capacity. The process for establishing these structures is built on a robust set of guiding principles, including those proposed by CalCCA in its DER Orchestration Comments.²² The Motion cites CalCCA's proposed guiding principles, as set forth below:²³

- Nondiscriminatory market access, operations, and dispatch;
- Independent monitoring and oversight of the DSO and market functions;
- Optimization of existing distribution grid capacity before authorization of capital investments;
- Competitive neutrality of the DSO and marketplace operator;
- Fair compensation for flexibility services; and
- Timely access to accurate customer usage, DER, integration capacity analysis, and grid data.²⁴

The Motion also identifies additional principles proposed by Advanced Energy United (AEU) to protect against market power and conflicts of interest, including:

- Non-discrimination;
- Comparability (no utility self-preference);
- Third-party access to grid infrastructure;

²² CalCCA's Comments in Response to the Assigned Commissioner's Ruling on Track 1 and Track 2 DER Orchestration, R.21-06-017 (Apr. 20, 2026) (CalCCA DER Orchestration Comments), at 12, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M605/K328/605328509.PDF>.

²³ Motion, at 12-13.

²⁴ CalCCA DER Orchestration Comments, at 12.

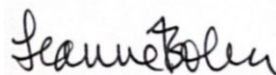
- Tariff-based standardized terms;
- Support for competition; and
- Transparent and timely data and processes.²⁵

The Commission should adopt the principles proposed by CalCCA and AEU as the basis for establishing safeguards to mitigate or eliminate potential conflicts of interest, prevent market manipulation, and ensure a level playing field for demand flexibility providers and DER aggregators. The Commission should adopt a governance structure and safeguards prior to approving IOU administration of a DER orchestration framework, and prior to closing the proceeding, or through a dedicated Track 2 phase, working group process, or a successor proceeding.

IV. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the foregoing response and looks forward to ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

September 25, 2026

²⁵ Motion, at 13.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Continue
Oversight of Electric Integrated Resource
Planning and Procurement Processes.

R.25-06-019

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION COMMENTS
ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING
COMMENTS ON ELECTRICITY PORTFOLIOS FOR THE 2027-2028
TRANSMISSION PLANNING PROCESS AND POTENTIAL FOR
GEOGRAPHICALLY-TARGETED PROCUREMENT**

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SUMMARY OF RECOMMENDATIONS¹

The Commission should:

- Use the most up to date deliverability, interconnection, and constraint information to ensure the portfolios reflect the best available information;
- Recognize that the portfolios developed for transmission planning, which are sensitive to uncertain inputs and assumptions, serve different purposes than near- to mid-term procurement requirements, which should align with resource procurement and development timelines and accommodating to market supply and prices;
- Adopt the recommended base case with modifications to enable a more feasible portfolio than the original base case that incorporates infeasible amounts of solar and storage and recognize that proactive transmission planning is necessary to support the development of the desired resources for which LSEs have planned in their 2026 IRPs;
- Modify the base case to retain the original intermediate targets of 30 MMT by 2030 and 25 MMT by 2035 to ensure continued progress towards SB 100 goals and utilize the 2025 IEPR Demand Forecast to ensure a feasible portfolio that includes the resources LSEs seek to procure without relaxing interim GHG targets;
- Adopt the timing and lower quantities of OOS resources in the base case, given the lack of demonstrated interest and progress towards developing OOS transmission to the CAISO boarder, so that in-state alternatives are properly planned for in the TPP;
- Work with the CAISO to reform the MIC process and provide stronger signals to the CAISO when MIC expansion is necessary to support OOS generation;
- Reconfigure and/or repurpose transmission that has already been approved for OSW so that it can still provide benefits, including increasing deliverability in Northern California, relieving congestion, supporting the delivery of imports, and relieving local constraints;
- Adopt the recommended sensitivity with modifications to include more gas retirements so that the portfolio identifies resources that are needed to replace emitting baseload resources;
- Update the busbar mapping process to: (1) include Cluster 16 data; (2) conduct an annual survey for entities to communicate their commercial interest in pre-queue projects; and (3) clearly identify more general areas rather than specific points of interconnection, so that projects are not unnecessary prevented from entering the interconnection process or TPD allocation process;

¹ Acronyms used herein are defined in the body of this document.

SUMMARY OF RECOMMENDATIONS continued

- Refrain from issuing geographically targeted procurement at this time, and instead develop a joint framework with the CAISO to assess the trade-offs of wires and non-wires alternatives, given the current level of analysis is insufficient to conclude that a procurement order is the most cost-effective path forward to resolve the constraint; and
- Allow for additional processes to explore the many additional questions associated with geographically targeted procurement, including questions on procurement responsibility, cost responsibility, procurement amounts, etc., before ordering geographically targeted procurement for the Western LA basin.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Continue
Oversight of Electric Integrated Resource
Planning and Procurement Processes.

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California Community Choice Association² (CalCCA) submits these comments pursuant to the *Administrative Law Judge’s Ruling Seeking Comments on Electricity Portfolios for the 2027-2028 Transmission Planning Process and Potential for Geographically-Targeted Procurement*³ (Ruling), dated August 31, 2026.

I. INTRODUCTION

CalCCA appreciates the California Public Utilities Commission’s (Commission) efforts to develop Transmission Planning Process (TPP) portfolios that reflect California’s evolving resource needs and that support the state’s reliability and policy objectives. The TPP plays an important role in identifying the transmission investments necessary to enable load-serving entities (LSE) to meet their future needs and to facilitate a reliable and affordable resource

² California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale’s Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, Valley Clean Energy, and WestLight Energy.

³ *Administrative Law Judge’s Ruling Seeking Comments on Electricity Portfolios for the 2027-2028 Transmission Planning Process and Potential for Geographically-Targeted Procurement*, Rulemaking (R.) 25-06-019 (Aug. 31, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M616/K589/616589361.PDF>.

portfolio that meets the state’s policy goals. The Commission’s recommended base portfolio makes two significant changes to policy assumptions from the 2026-2027 TPP base case by: (1) relaxing the greenhouse gas (GHG) targets for 2030 and 2035 from 30 million metric tons (MMT) and 25 MMT to 38 MMT and 30 MMT, respectively; and (2) unlike in previous TPP cycles, no longer forcing offshore wind (OSW) into the portfolio.

A. CalCCA Generally Supports the Base and Sensitivity Cases with Modifications to Retain the Interim GHG Targets and Use the Most Recent Demand Forecast

This recommended base case should be adopted with modifications to: (1) retain the original interim GHG targets; and (2) use the 2025 Integrated Energy Policy Report (IEPR) Demand Forecast rather than the 2024 IEPR Demand Forecast. The recommended base case includes an increased proportion of non-solar resources due to its more realistic solar build rates. Many community choice aggregators (CCA) seek to procure these non-solar resources, as reflected in their Integrated Resource Plans (IRP), but are not seeing them represented in the market in part due to transmission constraints.

However, CalCCA is concerned that the Commission’s method for developing the recommended base case includes relaxing the GHG targets. The original intermediate targets of 30 MMT by 2030 and 25 MMT by 2035 are important milestones that should be retained to ensure continued progress towards the 2045 Senate Bill 100⁴ goal through proactive transmission planning. While the original base portfolio that relies on the original intermediate targets includes a potentially infeasible amount of solar and storage, it also relies on an outdated load forecast. If this load forecast is replaced by the more recent 2025 IEPR Demand Forecast, a more feasible portfolio

⁴ Senate Bill 100 (SB 100) Ch. 312, Stats. 2018 (De León), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

is achieved that includes resources LSEs seek to procure. These changes result in a base case that is similar to the recommended base case without needing to relax the GHG targets.

Other elements of the base case seek to align the portfolio with commercial viability and should be adopted. The timing and lower quantities of out-of-state (OOS) resources in the base case recognizes lack of progress in developing the OOS transmission for delivery of generation to the California Independent System Operator (CAISO) boundary. Refraining from forcing offshore wind into the portfolio ensures the Commission identifies and plans for resources that can realistically support the state's near- and medium-term reliability and policy objectives while preserving flexibility to incorporate OSW as development conditions improve.

The Commission should adopt the recommended sensitivity portfolio with modifications consistent with those recommended for the base portfolio. That is, the sensitivity portfolio should be modified to maintain the original GHG targets and use the 2025 IEPR Demand Forecast. The sensitivity portfolio should also include an increased amount of gas retirements to ensure that the resulting portfolio identifies the resources needed to replace emitting baseload resources as those resources retire.

B. Portfolio Development and Busbar Mapping Should Reflect Evolving Development Conditions and Commercial Viability

Future portfolios and existing transmission investments should reflect evolving development conditions and commercial viability to minimize the risk of stranded investments. To do so, the Commission should work with CAISO to reform the Maximum Import Capability (MIC) process and establish stronger signals regarding when MIC expansion is necessary to support OOS generation. Transmission already approved to support OSW should be evaluated for opportunities to reconfigure or repurpose those investments to provide near- and medium-term system benefits, including increasing deliverability in Northern California, relieving congestion

and local constraints, and supporting the delivery of imports. The busbar mapping process should also be updated to incorporate Cluster 16 data, establish an annual process for entities to communicate their commercial interest in pre-queue projects, and identify broader geographic areas rather than unnecessarily limiting projects to specific points of interconnection (POI).

C. The Commission's IRP Processes Should Encourage Proactive Transmission Planning and Preserve Procurement Flexibility to Respond to Market Conditions

Overall, as the Commission refines the portfolios in the Ruling and develops future portfolios, the Commission should take a balanced approach that encourages proactive transmission development that preserves flexibility to respond to changing market and development conditions, ensures continued progress towards SB 100 goals, and ensures that transmission planning decisions support resources that LSEs can realistically procure and develop. The Commission should recognize the inherent uncertainty associated with long-term planning and ensure that the assumptions underlying the TPP portfolios remain grounded in the best available information and appropriately reflect the different purposes of transmission planning and near- to mid-term procurement requirements.

In particular, the Commission should distinguish between: (1) portfolios used to identify potential transmission needs over a long planning horizon; and (2) procurement requirements that must be responsive to resource development timelines, market supply, and prices. Transmission planning should provide a durable foundation for a diverse resource mix without prematurely translating uncertain long-term assumptions into near-term procurement obligations.⁵ Taken together, these recommendations would allow the Commission to advance

⁵ CalCCA has commented extensively on the need to avoid prescriptive procurement requirements based on modeled portfolios in R.20-05-003. *See, e.g., California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Additional Proposal for a*

transmission planning and resource development while maintaining appropriate distinctions between long-term planning assumptions and near-term procurement requirements.

D. The Commission Should Not Adopt Geographically Targeted Procurement Until the Commission and the CAISO Assess the Trade-Offs of Wires and Non-Wires Alternatives to Identify Most Cost-Effective Path Forward to Resolve the Constraint

With respect to geographically targeted procurement, the Commission should refrain from issuing a procurement order at this time. The current analysis does not sufficiently evaluate the tradeoffs between wires and non-wires alternatives to establish that procurement is the most cost-effective solution to the identified constraint. Before ordering geographically specific procurement, the Commission should develop, jointly with CAISO, a framework for evaluating wires and non-wires alternatives and their respective costs, benefits, and tradeoffs. The Commission should also allow additional process to address unresolved questions regarding procurement responsibility, cost responsibility, procurement quantities, and other implementation issues.

In summary, the Commission should:

- Use the most up to date deliverability, interconnection, and constraint information to ensure the portfolios reflect the best available information;
- Recognize that the portfolios developed for transmission planning, which are sensitive to uncertain inputs and assumptions, serve different purposes than near- to mid-term procurement requirements, which should align with resource procurement and development timelines and accommodating to market supply and prices;
- Adopt the recommended base case with modifications to enable a more feasible portfolio than the original base case that incorporates infeasible amounts of solar and storage and recognize that proactive transmission planning is necessary to support the development of the desired resources for which LSEs have planned in their 2026 IRPs;

Reliable and Clean Power Procurement Program, R.20-05-003 (Aug. 14, 2026) (CalCCA August Comments), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M615/K005/615005837.PDF>.

- Modify the base case to retain the original intermediate targets of 30 MMT by 2030 and 25 MMT by 2035 to ensure continued progress towards SB 100 goals and utilize the 2025 IEPR Demand Forecast to ensure a feasible portfolio that includes the resources LSEs seek to procure without relaxing interim GHG targets;
- Adopt the timing and lower quantities of OOS resources in the base case, given the lack of demonstrated interest and progress towards developing OOS transmission to the CAISO boarder, so that in-state alternatives are properly planned for in the TPP;
- Work with the CAISO to reform the MIC process and provide stronger signals to the CAISO when MIC expansion is necessary to support OOS generation;
- Reconfigure and/or repurpose transmission that has already been approved for OSW so that it can still provide benefits, including increasing deliverability in Northern California, relieving congestion, supporting the delivery of imports, and relieving local constraints;
- Adopt the recommended sensitivity with modifications to include more gas retirements so that the portfolio identifies resources that are needed to replace emitting baseload resources;
- Update the busbar mapping process to: (1) include Cluster 16 data; (2) conduct an annual survey for entities to communicate their commercial interest in pre-queue projects; and (3) clearly identify more general areas rather than specific points of interconnection, so that projects are not unnecessarily prevented from entering the interconnection process or Transmission Plan Deliverability (TPD) allocation process;
- Refrain from issuing geographically targeted procurement at this time, and instead develop a joint framework with the CAISO to assess the trade-offs or wires and non-wires alternatives, given the current level of analysis is insufficient to conclude that a procurement order is the most cost-effective path forward to resolve the constraint; and
- Allow for additional processes to explore the many additional questions associated with geographically targeted procurement, including questions on procurement responsibility, cost responsibility, procurement amounts, etc., before ordering geographically targeted procurement for the Western LA basin.

II. THE COMMISSION’S RECOMMENDED BASE CASE AND THE PROCESS FOR DEVELOPING IT DEMONSTRATES THE NEED FOR PROACTIVE TPP PORTFOLIOS AND RCPPP PROCUREMENT FLEXIBILITY

CalCCA understands the Commission’s motivation to modify the inputs and assumptions used to develop the TPP portfolios to “construct a more reasonable base case portfolio.”⁶ The Commission prudently recognized that the initial potential base case was “both unnecessarily

⁶ Ruling, at 13.

expensive to ratepayers and likely unrealistic in its build rates for solar and storage in the near term.”⁷ These concerns, however, also demonstrate the importance of distinguishing the purpose of the TPP portfolios from the purpose of establishing near- and mid-term procurement requirements, including through the proposed Reliable and Clean Power Procurement Program (RCPPP) in R.20-05-003.

The TPP base case is fundamentally a **long-term transmission planning tool**. Its purpose is to identify transmission solutions that can support California’s evolving resource needs and policy objectives under a range of plausible future conditions. Accordingly, the Commission should avoid constraining future TPP portfolios based primarily on near-term resource procurement feasibility in a manner that could delay transmission development. Transmission and interconnection constraints can themselves impede resource development, limit resource diversity, and increase reliance on a narrower set of resources. TPP portfolios should instead identify proactive, least-regrets transmission solutions that expand the set of resources that can ultimately serve California load and provide flexibility as resource development and market conditions evolve.

In addition, the Commission should encourage the CAISO to evaluate transmission solutions that are strategic long-term investments. This would provide the CAISO with the option to pursue transmission that is identified in the 20-Year Outlook early if it provides interim benefits or can facilitate the proactive development of resources in the portfolio. The TPP portfolios provide a holistic, long-term vision of resources needed to support a reliable and clean grid and should be used to build transmission to make those resources reality.

⁷ *Ibid.*

The RCPPP, by contrast, would establish **actual procurement requirements for LSEs** and therefore must account for considerations that are distinct from those used to develop long-term transmission planning portfolios. The Commission should not translate the modeled resource quantities in a TPP portfolio directly into prescriptive procurement obligations. As demonstrated by the recommended base case portfolio, changes to inputs and assumptions can materially change the modeled resource mix. Figure 3, for example, shows reductions in the modeled quantities of offshore wind, OOS wind, conventional geothermal, and location-constrained 12-hour storage relative to the previously transmitted portfolio.⁸ Such changes illustrate that modeled resource quantities are outputs of a planning exercise, not necessarily quantities that LSEs can or should be required to procure.

Procurement requirements established through the RCPPP should instead account for actual resource availability, development and interconnection timelines, transmission availability, market supply, and procurement costs. Prescriptive resource- or narrowly defined attribute-specific requirements based solely on modeled TPP portfolios could constrain LSE procurement flexibility, create opportunities for supplier market power where supply is limited, and require LSEs to procure resources on timelines that are not supported by actual project development. Such requirements could also increase the risk of stranded costs if the assumptions underlying the TPP portfolio subsequently change. The Commission should therefore use the TPP to identify and facilitate the transmission infrastructure necessary to support reliability and clean energy targets under a range of future uncertain outcomes, while establishing RCPPP procurement requirements through a separate process that is responsive to actual market and resource development conditions.

⁸ See Ruling, at 26.

III. CALCCA'S RESPONSES TO QUESTIONS IN SECTION 5 OF THE RULING

Questions Related to the 2027-2028 TPP Recommendations

- 1. Please comment on the modeling assumption updates made for this round of TPP recommendations. Are there other critical assumption changes that you recommend? Be as specific as possible about assumptions and data sources.**

The Commission should improve the modeling assumptions for this portfolio by using the most up to date deliverability and interconnection information. Importantly, the 2027-2028 TPP is the last annual Transmission Plan before CAISO transitions to its FERC 1920 schedule, which will result in comprehensive Transmission Plans every other year, rather than annually.⁹ The transition to this new schedule means that after the 2027-2028 TPP, the next TPP will not result in additional TPD until Cluster 20 in 2030. Accordingly, it is critically important that the 2027-2028 Transmission Plan is based upon the best available information.

The Commission should therefore incorporate the recently released 2026 updates on CAISO constraints.¹⁰ These updates include several significant changes that would impact RESOLVE modeling results. The Commission should also use Cluster 16 intake data to recalibrate resource availability. At a minimum, it should be a key part of busbar mapping along with the under-contract and "Review" resources from LSE 2026 IRP filings.

- 2. Do you support the recommended Base Case for the 2027- 2028 TPP? Provide rationale for your recommendation. If you prefer a different Base Case portfolio, describe it as specifically as possible.**

The Commission should adopt the recommended base case with modifications to: (1) retain the original interim GHG targets; and (2) use the 2025 IEPR Demand Forecast rather than the 2024 IEPR Demand Forecast. The Commission's recommended base portfolio makes two

⁹ See CAISO, *FERC Order No. 1920-A Compliance Update* (Mar. 13, 2025) at 8, <https://www.caiso.com/documents/presentation-ferc-order-no-1920-mar-13-2025.pdf>.

¹⁰ See *Transmission Capability Estimates for Use in the CPUC's Resource Planning Process* (July 15, 2026), <https://www.caiso.com/documents/transmission-capability-estimates-white-paper-2026.pdf>.

significant changes to policy assumptions from the 2026-2027 TPP base case: (1) it relaxes the GHG targets for 2030 and 2035 from 30 million metric tons (MMT) and 25 MMT to 38 MMT and 30 MMT, respectively; and (2) unlike previous TPP cycles, it no longer forces offshore wind into the portfolio. It also makes other modifications to align with commercial development interest and timelines, such as reducing the delay in in-state geothermal to seven years and updating the transmission potential for OOS wind.

CalCCA generally supports the base case given the increased share of non-solar resources in the portfolio relative to the original base case, which included potentially unrealistic solar build rates. CCAs are interested in procuring technologies other than solar and 4-hour storage and, in many cases, have included these resources in their IRPs. However, the availability of these resources at cost-effective prices is limited. This is in part due to transmission constraints. A portfolio should ensure transmission solutions are identified to support the development of these resources and ensure feasible build rates to ensure the plan can be implemented in an affordable manner.

Still, CalCCA is concerned that the Commission's method for developing the recommended base case includes relaxing the GHG targets. The original intermediate targets of 30 MMT by 2030 and 25 MMT by 2035 are important milestones that should be retained to ensure continued progress towards SB 100 through proactive transmission planning. While the original base portfolio that relies on the original intermediate targets includes a potentially infeasible amount of solar and storage, it also relies on an outdated load forecast that, if replaced

by the more recent 2025 IEPR Demand Forecast,¹¹ results in a more feasible portfolio similar to the recommended base case without needing to relax the GHG targets.

CalCCA ran RESOLVE with the 2024 IEPR load forecast and original intermediate targets of 30 MMT by 2030 and 25 MMT by 2035 using the 2027-2028 TPP model, which required 99 GW of new nameplate by 2035. This analysis found that the need for new resources is closer to 80 GW by 2035 if *either*: (1) the interim GHG-emissions targets are relaxed, while maintaining the SB 100 and SB 1020 targets; or (2) the interim GHG-emissions target is retained, and the load forecast is updated from the 2024 IEPR to the 2025 IEPR. This result is demonstrated in Figure 1, below. In all three cases in Figure 1, the GHG emissions are equal to the GHG trajectory because the emissions target is the binding constraint and driving the selected new build.

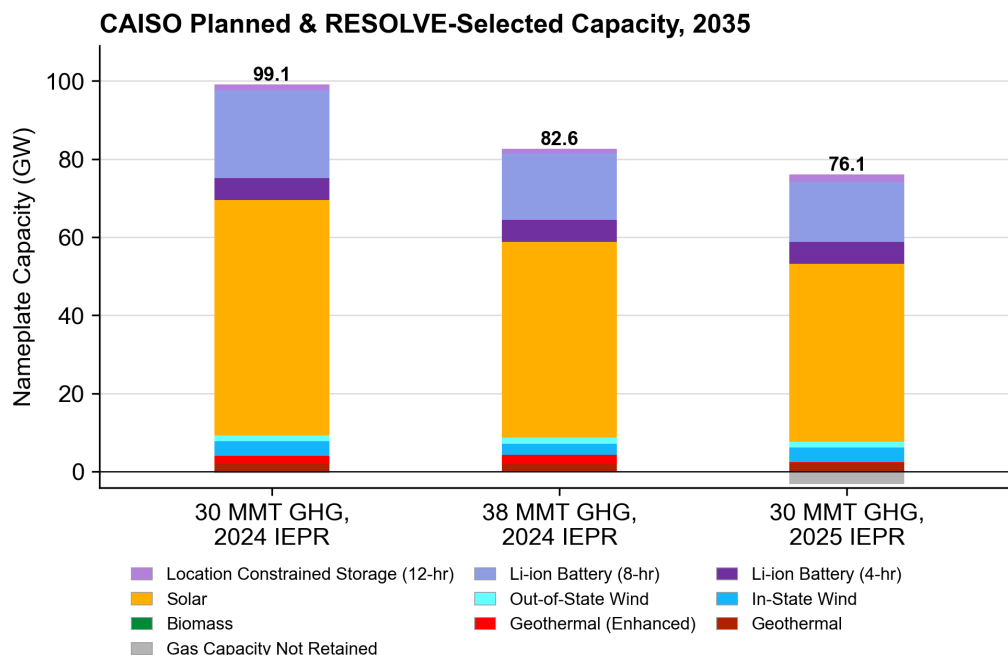


Figure 1: 2035 New Build From 2027-2028 TPP RESOLVE Model Under Different GHG and Load Forecast Scenarios

¹¹ Bailey, Stephanie, Jim Bartridge, Kadir Bedir, Mathew Cooper, Susan Ejlalmaneshan, Tom Flynn, Quentin Gee, et al. 2026. *Final 2025 Integrated Energy Policy Report*. California Energy Commission. Publication Number: CEC-100-2026-001-CMF, <https://efiling.energy.ca.gov/GetDocument.aspx?tn=271454&DocumentContentId=108996>.

Other elements of the base case wisely seek to align the portfolio with commercial viability. The timing and lower quantities of OOS resources in the base case recognize the lack of progress developing the OOS transmission for delivery of generation to the CAISO boundary. Refraining from forcing OSW into the portfolio could help ensure the Commission identifies and plans for resources that can realistically support the state's near- and medium-term reliability and policy objectives while preserving flexibility to incorporate offshore wind as development conditions improve. As described in response to Question 6, whether the Commission retains or removes offshore wind, it is necessary for the Commission and CAISO to evaluate whether Northern California transmission upgrades that have already been approved for OSW are needed for other system or local needs.

3. Please comment on whether the timing and quantities of out-of-state wind and/or geothermal selected in the recommended Base Case portfolio for the 2027-2028 TPP are commercially reasonable and why; also provide rationale for any modifications recommended

CalCCA supports reducing the geothermal delay from ten years to seven years, but recommends the Commission also refrain from remapping a significant amount of geothermal from in-state to out-of-state locations. This timeline aligns more closely with information CCAs have obtained from developers. It will also ensure transmission needed to deliver these locationally constrained resources is not a source of further delay. The inability to interconnect and receive deliverability is a significant roadblock to the delay of geothermal, and delaying inclusion of geothermal in the base case could create a "self-fulfilling prophecy." While CalCCA supports the modified timing of geothermal, it is concerned that the proposed base case relocates a significant amount of geothermal out-of-state. Assuming two GW of geothermal dependent of the High West Transmission project is likely overly ambitious given the status of the project. It

also links a significant amount of near-term capacity to a small set of developers, a single technology, and a single transmission project.

CalCCA also supports the modifications to the timing and quantities of OOS wind. While OOS wind is an attractive resource due to its complimentary output profiles and the difficulties in developing in-state wind, there is significant uncertainty around whether the OOS transmission needed to bring OOS wind to the CAISO boarder will be available to support the significant amount of OOS wind in prior portfolios. Assuming large quantities of OOS resources in the TPP can make the portfolio look attractive on paper while obscuring the substantial transmission-development steps necessary to make those resources deliverable. The ability to access OOS wind will require coordination across multiple jurisdictions, balancing authorities, and LSEs, and faces additional challenges such as permitting, siting, and cost allocation. The TPP portfolios should therefore not assume OOS resources at quantities or on a timeline for which there is not a demonstrated transmission-development pathway so that the state can plan for in-state alternatives when necessary.

- 4. Describe any other out-of-state wind, geothermal, and/or transmission projects that you are aware of, in addition to those already assumed in RESOLVE, that could meet California's needs. Be as specific as possible about assumptions and data sources.**

CalCCA has no comments at this time.

- 5. Comment on any actions the Commission should take to support the development of out-of-state transmission and/or generation to serve California's needs.**

The Commission and CAISO should work together on MIC reform to ensure that LSEs are able to bring out-of-CAISO resources into the CAISO Balancing Authority Area. The current MIC process leaves LSEs uncertain about their MIC allocations until the year-ahead. LSEs can

only lock-in MIC for multiple years if they have an RA contract active in the immediate RA year. This is insufficient to support long-term PPAs with OOS resources.

The Commission should provide stronger signals to the CAISO that MIC is necessary to support OOS generation. MIC can only be expanded if there is existing MIC or planned MIC driven by policy-driven transmission projects. The Commission can facilitate this MIC expansion by including OOS resources in the portfolios when LSEs have signaled commercial interest in procuring these projects.

6. Do you support offshore wind being removed from (i.e., not being forced into) the recommended Base Case portfolio for the 2027-2028 TPP? Why or why not?

CalCCA continues to support the state's efforts to advance emerging technologies, including OSW, that have the potential to contribute to California's long-term energy and climate objectives. At the same time, current signals from the market, the federal administration, and LSEs' IRPs suggest that many challenges remain unresolved before OSW can reach commercial operation at scale. It is therefore uncertain whether OSW will make a material contribution to the state's resource portfolio within the recommended base case's 10–15-year planning horizon.

Accordingly, CalCCA supports the Commission's decision not to force OSW into the recommended base case for the current planning horizon. This approach does not diminish the potential long-term value of OSW; rather, it will ensure that the Commission identifies and plans for resources that can realistically support the state's near- and medium-term reliability and policy objectives while preserving flexibility to incorporate OSW as development conditions improve.

This approach also demonstrates the importance of developing portfolios and Transmission Plans that are robust across a range of future scenarios and minimize the risk of stranded investment. The CAISO already approved transmission to support OSW in the 2023-

2024 Transmission Plan.¹² CalCCA shares the Commission’s interest in preserving the value of these investments and exploring whether they can serve other purposes in the event OSW development occurs later than anticipated.¹³ The Commission and CAISO should therefore perform additional analysis to evaluate how already-approved transmission could be reconfigured or otherwise used to support other system or local needs, including increasing deliverability in Northern California, relieving congestion, supporting the delivery of imports, relieving local constraints, and/or reducing reliance on local gas. Any such analysis should account for the potential future development of OSW and avoid impacting deliverability allocations to resources that are already online, in the queue, or in active development.

7. Do you support the recommended Sensitivity portfolio for analysis in the 2027-2028 TPP? Provide rationale for your recommendation. If you prefer a different Sensitivity portfolio, describe it as specifically as possible.

For the reasons described in response to Question 3 above, CalCCA generally supports the Limited OOS Resources sensitivity case with modifications. Given the uncertainty associated with OOS transmission, including the additional challenges with developing regional transmission and lack of development progress, a limited OOS resource sensitivity would allow the Commission and the CAISO to plan for in-state resource and transmission alternatives if OOS transmission does not develop as previously assumed.

The proposed sensitivity portfolio should be modified in two ways to ensure continued progress towards GHG emissions reductions, planning towards the most up-to-date load forecast information, and fully evaluating how to reduce reliance on gas-fired resources. *First*, the Commission should align the sensitivity case with the base case by: (1) retaining the interim

¹² CAISO, *2023-2024 Transmission Plan* (May 23, 2024), https://stakeholdercenter.caiso.com/InitiativeDocuments/BOARDAPPROVED_2023-2024_TransmissionPlan.pdf.

¹³ See Ruling, at 20.

GHG targets; and (2) using the 2025 IERP load forecast. *Second*, the Commission should increase the amount of gas retirements assumed in the sensitivity so that the portfolio includes resources that are needed to replace emitting baseload resources. CalCCA is concerned that the Commission transmitted a high-gas retirement sensitivity to the CAISO in the 2024-2025 Transmission Plan, but more work is necessary to fully evaluate transmission solutions necessary to reduce dependency on gas resources, especially in local resources. This sensitivity, combined with the recommendations in response to Questions 9 and 17, will help advance the evaluation of transmission and resource alternatives.

8. Comment on the busbar mapping methodology updates included for this TPP cycle. Questions Related to Potential Geographically-Targeted Procurement Requirements in the Western LA Basin

CalCCA supports the inclusion of permitting data and substation upgrade costs into the commercial interest criteria and recommends three additional improvements for this portfolio development cycle. *First*, the Commission should include Cluster 16 data in the busbar mapping in this cycle, including projects seeking both energy-only and full capacity deliverability status to ensure the most complete and current information about where resources are seeking interconnection.

Second, to further enhance the commercial interest criteria, the Commission should conduct an annual survey for entities to communicate their commercial interest in new capacity projects for consideration in the busbar mapping. This could include the LSE commercial interest scoring used in the interconnection process but should also include interest outside of areas with existing or planned deliverability so that a diverse set of technologies, developers, and locations are identified in advance of them entering the interconnection queue. Obtaining pre-queue project status would improve commercial interest datasets, which may currently be limited due to how the new IPE processes limited where projects can apply to enter the queue.

Third, the Commission should modify its busbar mapping process to clearly identify more general areas rather than specific points of interconnection, so that projects are not unnecessarily prevented from entering the interconnection process or TPD allocation process. Identifying specific POI rather than broader areas has proven to be too limiting – especially for locationally constrained resources that cannot easily switch POIs to align with a narrowly mapped portfolio. Many long-lead-time (LLT) resources, such as geothermal resources, have uncertain and complex siting constraints. Locationally constrained resources should be allowed some flexibility in POIs for interconnection intake and TPD reservations. The CAISO has recognized the need for flexibility in its Cluster 16 guidance,¹⁴ and the Commission should align its busbar mapping to reflect a consistent level of flexibility.

9. Is it appropriate for the Commission to issue a geographically-targeted procurement order designed to alleviate the constraint at Mesa identified by the CAISO in the 2025-2026 TPP, instead of leaving it to the CAISO to pursue a wires-based transmission alternative? Why or why not?

No, the Commission should not issue a geographically-targeted procurement order at this time. The level of analysis provided on the tradeoffs between the wires and non-wires alternatives is insufficient to conclude that a procurement order is the best way to address the constraint. The CAISO’s 2026-2027 TPP workshop, held on September 23 and 24, 2026, further indicated that utilizing storage to meet local reliability is still subject to further analysis, and that there are potentially cost-effective wires-based transmission solutions that can be pursued to enhance the local area’s reliability.¹⁵ The CAISO and the Commission must consider the cost of each alternative relative to the lifespan of the asset and other benefits the solutions could provide (*e.g.*,

¹⁴ CAISO, *Information on Intake and Scoring of Long Lead Time Projects for C16* (Sept. 17, 2026), at 2, <https://www.caiso.com/documents/q-and-a-long-lead-time-resource-for-c16.pdf>.

¹⁵ CAISO, *2026-2027 Transmission Planning Process (September 23-24, 2026)*, at 183.

other constraints the solution could address). Importantly the analysis needs to quantify the system value of transmission alternatives versus resource alternatives, rather than a simple cost check.

Issuing such an order would also risk exposing customers to market power. The Ruling states that the proposed procurement quantity “would meet the CAISO’s identified need only if all projects already in the interconnection queue materialize. If all queue projects do not materialize, there could be a need for an additional transmission solution, even with the proposed procurement order.”¹⁶ A procurement order at the level necessary to resolve the constraint would therefore subject customers to potential market power exertion from suppliers. It is also unlikely that all projects in the queue will materialize, meaning some level of transmission investment may still be needed even if a procurement order was issued. Subjecting customers to these costs without fully understanding the feasibility, costs, and benefits of this solution and its alternatives is not a prudent path forward.

For these reasons, the Commission should not order geographically targeted procurement at this time. Instead, the Commission and the CAISO should jointly assess wires and non-wires alternatives and their trade-offs using the criteria described in response to Question 17 before any geographically-specific procurement is ordered.

10. If the Commission orders geographically-targeted procurement, what amount should the Commission require?

As stated in response to Question 9, the information provided at this stage is insufficient to order procurement of any amount at this time. Before determining whether geographically-targeted procurement should be ordered the Commission and the CAISO should jointly assess wires and non-wires alternatives and their trade-offs using the criteria described in response to Question 17. If a determination is made that a procurement order is necessary following this assessment, the

¹⁶ Ruling, at 34-35.

Commission should conduct additional process to explore the many additional questions associated with geographically targeted procurement, including questions on procurement responsibility, cost responsibility, procurement amounts, cost containment measures, etc.

- 11. If the Commission orders geographically-targeted procurement, which LSEs should be responsible for soliciting the procurement?**

See response in Question 10.

- 12. If the Commission orders geographically-targeted procurement, should the Resource Adequacy Local CPE play any role? If so, what role? If the resources continue to provide the transmission value but cease to provide a local resource adequacy value in the future, should the Local CPE continue to procure the resource? Why or why not?**

See response in Question 10.

- 13. If the Commission orders geographically-targeted procurement, which LSEs should be responsible for paying for the costs of procurement?**

See response in Question 10.

- 14. If the Commission orders geographically-targeted procurement, how should cost recovery be handled (e.g., should the Commission use the Cost Allocation Mechanism or another approach)?**

See response in Question 10.

- 15. If the Commission orders geographically-targeted procurement, what, if any, cost control mechanism and/or market power mitigation mechanisms should the Commission put in place?**

See response in Question 10.

- 16. If the Commission orders geographically-targeted procurement, should utility-owned resources be able to fulfill the need, and if so, what rules or limitations should the Commission place on these types of resources?**

See response in Question 10.

- 17. Should, and if so, how should the CAISO and the Commission approach developing a joint framework to enable future geographically-targeted procurement, to address transmission constraints? What elements are critical for the Commission to consider in creating such a framework?**

The CAISO and the Commission should develop a joint framework to assess wires and non-wires alternatives and their trade-offs before any geographically-specific procurement is ordered. This assessment should:

- Identify transmission alternatives necessary for upgrade to reduce/remove constraints by local area;
- Quantify the cost of transmission upgrades to reduce each constraint per MW by local area;
- Identify the maximum amount of storage, and clean generation to charge the storage, within each local area necessary to reliably operate without emitting resources;
- Identify the suitable land for each type of clean generating technology or storage within the local area;
- With assistance of the CAISO, identify the effectiveness factor of each suitable site; Develop a cost estimate based on 3-5 to develop generation/storage within the local area to address the constraints;
- Evaluate, by local area, which option is the most cost effective and feasible to address clean energy needs of the local areas; and
- Identify the broader system value of each alternative.

Questions Related to Potential GHG Emission Targets for Preferred System Plan Analysis

18. Comment on the appropriate GHG targets for next year's PSP to assume for 2030 and 2035, and any other years recommended, for purposes of analysis. Provide rationale for your recommendation.

As described in response to Question 2 above, CalCCA is concerned that the Commission's proposed method for developing this year's TPP base case includes relaxing the GHG constraints, rather than using more up-to-date load growth assumptions, to ensure feasible build rates. Next year and moving forward, the Commission should evaluate the future trajectory of GHG targets when developing inputs and assumptions (I&A), instead of following the development of the portfolio. This will allow parties to evaluate the proposed GHG targets in the full context of the inputs and assumptions, including load growth assumptions, recent historical GHG emissions trajectory, and other factors, and provide input in advance of portfolio development.

Other

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

A. The Commission Should Compare the Portfolios to Interconnection Queue Data for the Purposes of LLT Designations in the CAISO's Interconnection Intake Process

The Commission should use interconnection queue analysis to designate resources as LLT for the purposes of interconnection queue intake. The CAISO's Interconnection Process Enhancements (IPE) adopted a scoring process for determining which interconnection requests will enter the queue.¹⁷ Part of this scoring process is a consideration of whether a resource is considered LLT. The CAISO looks to Local Regulatory Authorities to designate resources as LLT.¹⁸ To do this, the Commission should conduct an analysis of the interconnection queue to determine which technologies are not sufficiently represented in the interconnection queue.¹⁹ Resources that are not sufficiently represented should be designated as LLT for the purposes of interconnection intake under the IPE rules.

B. The Commission Should Document Its Process for Identifying Distributed Generation Nodes in the Portfolio for Purposes of the CAISO DGD Study

The Commission should include written documentation in its annual TPP materials that explains the Commission's process for identifying distributed generation (DG) nodes in the portfolio, which serve as the input to the CAISO's distributed generation deliverability (DGD) study, and what role stakeholders can play in the identification process. Each year, the CAISO

¹⁷ CAISO, *2023 Interconnection Process Enhancements, Track 2 Final Proposal* (Mar. 28, 2024), at 65, <https://stakeholdercenter.caiso.com/InitiativeDocuments/FinalProposal-InterconnectionProcessEnhancements2023Track2.pdf>.

¹⁸ *Ibid.*

¹⁹ To accomplish this, the Commission should compare the amounts of each technology in Phase II of the CAISO interconnection queue with the amounts in the recommended TPP portfolio. If a technology is not sufficiently represented in the interconnection queue to cover the portfolio need, the Commission should designate the technology as LLT. CalCCA previously provided an example of the analysis necessary to designate a resource as LLT. See CalCCA August Comments, at 22.

issues a report with the results of its DGD study, explaining how the CAISO studies specific nodes for assignment of deliverability status to DG resources connected or requesting interconnection below those nodes. Per the CAISO's tariff section 40.4.6.3, the CAISO determines and adds DG amounts to the study model by first identifying all DG nodes that have non-zero distributed generation MW in the most recent transmission plan renewable portfolios. However, over the past several years, zero distributed generation has been identified in renewable portfolios for the San Diego Gas & Electric Company (SDG&E) service territory, and thus no nodes in the SDG&E area have been studied by the CAISO for potential DGD. Most recently, in the 2025-2026 DGD Study, the CAISO reported that the 2025-2026 renewable portfolios identified zero MW of generic FCDS distributed generation in the base portfolio for all service areas, meaning only nodes identified by publicly-owned utilities were studied.²⁰

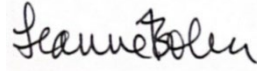
While the CAISO presents annual documentation about the results of the study, the Commission currently does not provide transparent documentation within its annual TPP materials around how the Commission's adopted TPP portfolios serve as inputs to the DGD study process. Further information about the Commission's role in the CAISO DGD study and what assumptions and criteria inform the Commission's determination of distributed generation, including but not limited to distributed solar and storage, for the purpose of this study is needed to help stakeholders better understand and engage with the current process.

²⁰ CAISO, *Resource Adequacy Deliverability for Distributed Generation, 2025-2026 DG Deliverability Assessment Results*, <https://www.caiso.com/documents/2025-2026-deliverability-for-distributed-generation-study-results-report-final.pdf>.

IV. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

A handwritten signature in black ink, appearing to read "Leanne Bober", is centered below the "Respectfully submitted," text.

Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

September 28, 2026

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Association of Bay Area Governments (CPUC ID 941) for Approval of the Bay Area Regional Energy Network 2028-2031 Portfolio Plan and 2028-2035 Business Plan

And Related Matters.

Application 26-03-009
(Filed March 16, 2026)

Application 26-03-010
Application 26-03-011
Application 26-03-012
Application 26-03-013
Application 26-03-014
Application 26-03-015
Application 26-03-017
Application 26-03-018
Application 26-03-019
Application 26-03-020
Application 26-03-021
Application 26-03-028
(Consolidated)

**NOTICE OF AVAILABILITY OF UPDATED AND SUPPLEMENTAL
EXHIBITS FOR THE APPLICATION OF MARIN CLEAN ENERGY FOR
APPROVAL OF 2028-2031 ENERGY EFFICIENCY PORTFOLIO PLAN
AND 2032-2035 ENERGY EFFICIENCY BUSINESS PLAN**

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September 30, 2026

**BEFORE THE PUBLIC UTILITIES COMMISSION
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Pursuant to Rule 1.9 of the Commission’s Rules of Practice and Procedure and September 2, 2026 Administrative Law Judge Valerie Kao issued ADMINISTRATIVE LAW JUDGE’S RULING DIRECTING SUBMISSION OF CORRECTIONS AND SUPPLEMENTAL INFORMATION FROM ALL BUSINESS PLAN APPLICANTS, Marin Clean Energy (“MCE”) hereby submits this Notice of Availability of the exhibits and supporting documents to the March 16, 2026, *Application of Marin Clean Energy for Approval of 2028-2031 Energy Efficiency Portfolio Plan and 2032-2035 Energy Efficiency Business Plan* (“Application”).

The supporting material includes:

Exhibit MCE – 01	Updated Testimony of Marin Clean Energy Regarding its 2028-2031 Energy Efficiency (“EE”) Portfolio Plan and 2032-2035 EE Business Plan
Exhibit MCE – 02	Updated EE Program Cards
Exhibit MCE – 03	Updated California Energy Data and Reporting System (“CEDARS”) Filing Links and Receipts
Exhibit MCE – 04	Corrections and Supplemental Information from All Business Plan Applicants
Redlined Documents	All Redlined Exhibits

This Notice of Availability is being served on all parties listed on the official service lists for Rulemaking (A.) 26-03-009 et al.

As of September 30, 2026, the updated supporting materials, are available at the following links:

- Updated Exhibit MCE-01:
<https://mcecleanenergy.org/wp-content/uploads/2026/09/MCE-Exhibit-1-Updated.pdf>
- Updated Exhibit MCE-02:
<https://mcecleanenergy.org/wp-content/uploads/2026/09/UpdatedExhibit2.pdf>
- Updated Exhibit MCE-03:
<https://mcecleanenergy.org/wp-content/uploads/2026/09/UpdatedExhibit3.pdf>
- New Exhibit MCE-04:
<https://mcecleanenergy.org/wp-content/uploads/2026/09/Exhibit-4.pdf>
- Redlined Documents:
<https://mcecleanenergy.org/wp-content/uploads/2026/09/RedlineDocuments.pdf>
- Notice of Availability:
<https://mcecleanenergy.org/wp-content/uploads/2026/09/NewNoticeOfAvailability.pdf>

Direct request for the Application, Exhibits and supporting documents may be submitted to:

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Respectfully submitted,

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September 30, 2026