Regulatory Filings

Comments on Revised Straw Proposal and discussion on June 18, 2026

Initiative: Demand and distributed energy market integration

Comment period

Jun 17, 2026, 08:00 am - Jul 01, 2026, 05:00 pm

Submitting organizations

California Community Choice Association

MCE

California Community Choice Association

Submitted on 07/01/2026, 03:38 pm

Contact

Lauren Carr (lauren@cal-cca.org)

1. Please provide your organization's feedback on the DDEMI meeting discussion on June 18, 2026 and the "Demand and Distributed Energy Market Integration Track 1: Revised Straw Proposal: Reflecting End-User Exports in Demand Response" paper

The California Community Choice Association (CalCCA) appreciates the opportunity to provide comments on the Demand and Distributed Energy Market Integration (DDEMI) Track 1 Revised Straw Proposal (RSP). The CAISO proposes to enable Demand Response (DR) exports, capped at the resource level. The RSP makes an important near-term incremental step to better leverage existing demand flexibility on the California Independent System Operator (CAISO) system. The CAISO should advance the proposal for implementation in 2027, as proposed.

To further advance demand flexibility opportunities, the CAISO should facilitate discussions in future initiative tracks to remove barriers to exports beyond the resource level. While DR exports are supported through the Distributed Energy Resource Aggregation (DERA) model, there is currently no RA pathway for DERA resources, limiting its use. Future discussions in coordination with the California Public Utilities Commission (CPUC) should seek to remove barriers to exporting at the resource aggregation level, whether through future enhancements to the modified Proxy Demand Resource model or through the existing DERA model.

CalCCA is concerned about the deliverability discussions that occurred during the stakeholder meeting. The CAISO's suggestion that, if DR participation grows, DR may require a transmission plan deliverability (TPD) allocation demonstrates potential flaws with the deliverability methodology overall that must be addressed. ***First***, as discussed in CalCCA's comments on the On-Peak Deliverability Assessment Methodology Refinements, while CalCCA agrees that DR should be modeled in deliverability studies, the CAISO has not demonstrated that its proposed DR modeling is necessary or appropriate.[1] ***Second***, it raises cost causation questions around equitable funding of the network upgrades necessitated by this potential change. Deliverability issues caused by changes in demand may not be attributable to individual generators (or DR resources). In addition, DR aggregations are fluid, and the customers within an aggregation can change over time. The impacts of demand flexibility and load composition on available deliverability should be carefully explored to determine whether and when network upgrades are required, and how the upgrades should be funded.

CalCCA therefore recommends that the CAISO ***hold a stakeholder process to gather meaningful input on the proposed refinements to the deliverability assessment methodology and allow stakeholders to propose additional refinements on the overall methodology***, with the goal of establishing a methodology that clearly and transparently considers DR impacts on deliverability. As an alternative, the CAISO could maintain the current deliverability process while conducting a sensitivity analysis to evaluate DR impacts. This sensitivity would help to inform the CAISO and stakeholders regarding any necessary further actions.

[1] Specifically, the CAISO's method appears to stem from a concern that increased DR in local areas could strand deliverable resources. It is CalCCA's understanding that the inclusion of DR is not necessarily to limit or reduce deliverability, but to examine the manner in which increased amounts of behind-the-meter storage used as DR are impacting the ability to export local area resources to loads outside of the local area. While CalCCA agrees that this gathering of information is necessary to inform the CAISO of grid reliability and deliverability, it is not clear how the inclusion in the test used to assess deliverability will impact currently interconnecting resources. If the effort is simply to gain an understanding, then it seems the CAISO could obtain that understanding by running a sensitivity analysis in addition to the deliverability assessment. By doing so, entities could be assured that the sensitivity will not affect outcomes at this time.

2. Please submit your organization's overall comments on Track 1

See response in Section 1 above.

3. Does your organization support, support with caveats, oppose, or oppose with caveats the proposal? Please explain the rationale for your position.

CalCCA supports the proposal for the reasons described in Section 1 above.

4. What key change(s) would your organization recommend to improve the proposal?

CalCCA has no comments at this time.

5. Please provide your organization's feedback on the applicability of the Track 1 proposal to: 1.) All Balancing Authority Areas (BAAs) 2.) Both Proxy Demand Resource (PDR) and Reliability Demand Response Resource (RDRR) market models.

CalCCA has no comments at this time.

6. Please provide your organization's feedback on the ISO BAA deliverability discussion, including any operational or market implications.

See response in Section 1 above.

7. Please provide your organization's feedback on the proposal to limit participation to customers with an approved interconnection for export onto the distribution system, including the implementation of this requirement as an attribute in CAISO's Demand Response Registration System (DRRS).

CalCCA understands the concerns raised by the CPUC about preventing double compensation between wholesale and retail DR programs and agrees it is appropriate to limit participation to customers with an approved interconnection for export to the distribution system at this time. However, preventing Net Billing Tariff (NBT) customers, who are Rule 21 approved and currently export, from participating in wholesale markets strands capacity that could otherwise deliver significant value to the system when it is most needed. CalCCA therefore recommends that the CAISO, in coordination with the CPUC, explore future pathways that would allow customers under the NBT to participate in R.25-09-004.[1]

[1] *OIR to Enhance Demand Response in California*, R.25-09-004, (Sep. 18, 2025).

8. Please provide your organization's feedback on the proposed design to zero out at the resource-level and allow the Scheduling Coordinator (SC) to determine which end-use customers are zeroed out.

CalCCA understands the CAISO's proposal to limit participation to the resource level, but, as described in Section 1 above, recommends having future discussions on how to remove barriers to exporting beyond the resource level, whether through enhancements to the modified Proxy Demand Resource model or through the DERA model.

CalCCA supports the proposal to allow SCs to determine how to zero out exports at the resource level. CCAs are best positioned to develop equitable methods to zero out resource-level exports in their programs and should be allowed to do so.

9. Please provide your organization's feedback on the applicability of this proposal to all Performance Evaluation Methodologies (PEMs).

CalCCA supports the CAISO expanding this proposal to apply to all PEMs. The previous proposal to limit export capability to resources using Meter-Generator-Output (MGO) baseline could have significantly limited export ability, given the limited use of the MGO baseline.

10. Does your organization have concerns with how baselines will be calculated or adjusted when end-use exports are netted out? Please describe any implications for measurement, verification, or settlement accuracy.

CalCCA has no comments at this time.

11. Please provide any additional comments, feedback, or examples. You may upload examples or data using the Attachments field below.

CalCCA has no additional comments at this time.

MCE

Submitted on 07/01/2026, 04:22 pm

Contact

Jordyn Bishop (jbishop@mceCleanEnergy.org)

1. Please provide your organization's feedback on the DDEMI meeting discussion on June 18, 2026 and the "Demand and Distributed Energy Market Integration Track 1: Revised Straw Proposal: Reflecting End-User Exports in Demand Response" paper

MCE appreciates the opportunity to submit these comments on the meeting discussion on June 18, 2026 and the "Demand and Distributed Energy Market Integration Track 1: Revised Straw Proposal: Reflecting End-User Exports in Demand Response" paper. MCE supports the Track 1: Revised Straw Proposal.

2. Please submit your organization's overall comments on Track 1

MCE supports Track 1 as the most immediate near-term solution in demand response participation model reforms. MCE commends and supports the CAISO's goal of bringing the Track 1 proposal to the WEM Governing Body Primary Authority in August 2026.

3. Does your organization support, support with caveats, oppose, or oppose with caveats the proposal? Please explain the rationale for your position.

MCE supports the Track 1 proposal. The Track 1 proposal addresses a critical limitation of the current demand response participation models by allowing demand response providers and the CAISO to capture the additional export capacity that already exists, while maintaining wholesale demand response as a load curtailment product at the resource level.

4. What key change(s) would your organization recommend to improve the proposal?

MCE has no comments at this time.

5. Please provide your organization's feedback on the applicability of the Track 1 proposal to: 1.) All Balancing Authority Areas (BAAs) 2.) Both Proxy Demand Resource (PDR) and Reliability Demand Response Resource (RDRR) market models.

MCE supports applying the Track 1 proposal to all Balancing Authority Areas, and both Proxy Demand Resource (PDR) and Reliability Demand Response Resource (RDRR) market models.

6. Please provide your organization’s feedback on the ISO BAA deliverability discussion, including any operational or market implications.

MCE has no comments at this time.

7. Please provide your organization’s feedback on the proposal to limit participation to customers with an approved interconnection for export onto the distribution system, including the implementation of this requirement as an attribute in CAISO’s Demand Response Registration System (DRRS).

MCE supports the Track 1 proposal requirement that exporting customers must have an approved interconnection agreement for export onto the distribution system.

8. Please provide your organization’s feedback on the proposed design to zero out at the resource-level and allow the Scheduling Coordinator (SC) to determine which end-use customers are zeroed out.

MCE supports the proposed design to zero out at the resource-level, rather than the individual customer level. MCE also supports allowing the Scheduling Coordinator (SC) to determine which end-use customers would be zeroed out.

9. Please provide your organization’s feedback on the applicability of this proposal to all Performance Evaluation Methodologies (PEMs).

MCE supports the application of the Track 1 proposal across all Performance Evaluation Methodologies (PEMs).

10. Does your organization have concerns with how baselines will be calculated or adjusted when end-use exports are netted out? Please describe any implications for measurement, verification, or settlement accuracy.

MCE has no comments at this time.

11. Please provide any additional comments, feedback, or examples. You may upload examples or data using the Attachments field below.

As the DDEMI effort explores longer-term reforms, MCE encourages the CAISO to consider how current aggregation and registration rules can limit the full potential of the Track 1 proposal. Currently, when the composition of an aggregation changes, DRPs must effectively recreate and reregister the aggregation, which significantly limits overall scalability. Future enhancements to PDR should enable more dynamic portfolios and reduce associated administrative burdens, such as by allowing for more flexible or “like-for-like" substitution of end-users within an aggregation.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking for Oversight of Energy Efficiency Portfolios, Policies, Programs, and Evaluation.	Rulemaking 25-04-010 (Filed April 24, 2025)

OPENING COMMENTS OF MARIN CLEAN ENERGY ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON BUDGET APPROACH FOR COMMUNITY CHOICE AGGREGATORS THAT ELECT TO ADMINISTER ENERGY EFFICIENCY PROGRAMS

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July 1st, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking for Oversight of Energy Efficiency Portfolios, Policies, Programs, and Evaluation.	Rulemaking 25-04-010 (Filed April 24, 2025)

OPENING COMMENTS OF MARIN CLEAN ENERGY ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON BUDGET APPROACH FOR COMMUNITY CHOICE AGGREGATORS THAT ELECT TO ADMINISTER ENERGY EFFICIENCY PROGRAMS

I. Introduction

Pursuant to Rule 6.2 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), Marin Clean Energy ("MCE"), respectfully submits these Opening Comments on *Administrative Law Judge's Ruling Seeking Comments on Budget Approach for Community Choice Aggregators that Elect to Administer Energy Efficiency Programs* ("Ruling") *and Staff Proposal to Modify Budget Formula for Community Choice Aggregators to Elect to Administer Energy Efficiency Funds* ("Staff Proposal") issued on June 8th, 2026. The Ruling invited Opening Comments through June 24th, 2026. On June 19th, 2026, Administrative Law Judge Kao issued the *Email Ruling Granting Extension Request for Comments on June 8, 2026 Staff Proposal Ruling* that granted an extension allowing Opening Comments through July 1st, 2026. MCE submits these timely comments in response.

MCE is a community choice aggregator ("CCA") with experience both previously as an Elect-to-Administer ("ETA") program administrator ("PA") of energy efficiency ("EE") programs[1] and presently as an Apply-to-Administer PA since 2013.[2] MCE thanks the Commission for its thoughtful Staff Proposal and submits recommendations for the inclusion of investor-owned utility ("IOU") nonbypassable charge collections in EE annual reports.

II. MCE Responses to Staff Proposal Questions

- *3. To reduce existing ambiguity and add uniformity, what is the most useful way for the electric investor-owned utilities to illustrate their energy efficiency nonbypassable charge collections in their Energy Efficiency Annual Reports?*

MCE strongly supports IOU reporting on their EE nonbypassable charge collections in their EE Annual Reports.[3] Beyond its utility for the ETA budget formula, MCE views this reporting requirement as consistent with Governor Newsom and the legislature's recent guidance to the Commission on EE and other public purpose programs.[4] The Governor and legislature directed the Commission to provide greater transparency on the cost, value, performance and benefits of EE and other public purpose programs.[5] While PAs, including the IOUs, already publicly provide robust information on EE programs,[6] the nonbypassable charge annual collections is a relevant and helpful addition. MCE supports requiring nonbypassable charge collections in IOU EE Annual Reports.

[1] Resolution E-4518, August 2012, Ordering Paragraph 1 ("Marin Energy Authority's 2012 energy efficiency program administration plan, as submitted on June 22, 2012, is certified pursuant to Public Utilities Code Section 381.1(f).") (MCE was formerly Marin Energy Authority).
[2] Decision ("D.") 12-11-015, *Decision Approving 2013-2014 Energy Efficiency Programs and Budgets* at 50, Ordering Paragraph ("OP") 1 at 130 (November 15, 2012) (approving MCE EE portfolio); D.23-06-055, Decision Authorizing Energy Efficiency Portfolios for 2024-2027 and Business Plans for 2024-2031, OP 1 (July 3, 2025).
[3] Staff Proposal, p. 14.
[4] *See*, *e.g.*, Executive Department State of California, EXECUTIVE ORDER N-5-24, October 30th, 2024, available at: https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf, pp. 1-2; Assembly Bill 3264 (Petrie-Norris), sections 1(b), 3(b), 2(a).
[5] *Id*.
[6] *See* California Energy Data and Reporting System (CEDARS), available at: https://cedars.cpuc.ca.gov (e.g. budgets, annual reports, quarterly claims etc).

MCE recommends the Commission direct the Reporting Policy Coordination Group ("Reporting PCG")[7] add additional tabs to the EE Annual Report Excel template along with a designated section in the EE Annual Report narrative template for IOU nonbypassable charge collections.[8] Each year, the Reporting PCG develops the EE Annual Report narrative and Excel templates that all PAs must use to ensure consistent annual reporting data. All PAs participate in this process and may propose specific language and requirements to be agreed upon by all PAs. To ensure consistency of reported data and a fair reporting process, MCE finds the Reporting PCG the appropriate venue to update existing templates to incorporate this vital information.

III. Conclusion

MCE thanks the Commission and Energy Division staff for their continued leadership on EE policy and the opportunity to comment on the Staff Proposal. MCE appreciates the Commission's willingness to partner with diverse PAs and stakeholders to ensure EE programs meet California's evolving and varied energy needs.

Respectfully submitted,

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Dated: July 1st, 2026.

[7] *See e.g.* Resolution E-5387 OPs 3, 9 (September 23, 2025); D.23-06-055 OP 23 (July 3, 2023).
[8] Staff Proposal, p. 14 (describing the narrative section of annual reports).

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IN THE SUPREME COURT OF CALIFORNIA

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Petitioner,

v.

PUBLIC UTILITIES COMMISSION

Respondent,

PACIFIC GAS AND ELECTRIC COMPANY et al.

Real Parties in Interest.

After Order Summarily Denying Petition for Review
by the Court of Appeal, Third Appellate District
Case No. C105174

From Public Utilities Commission Decision
Nos. 25-06-049 and 25-10-061

PETITION FOR REVIEW

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TO THE HONORABLE CHIEF JUSTICE AND ASSOCIATE JUSTICES OF THE CALIFORNIA SUPREME COURT:

Petitioner California Community Choice Association ("CalCCA") respectfully petitions this Court to review the decision of the Third District Court of Appeal in *California Community Choice Association v. Public Utilities Commission, et al.* (June 25, 2026, No. C105174), attached as Exhibit A ("Order"). Because the decision was made in a summary order and became final immediately (Cal. Rules of Court, rule 8.730, subd. (c)(1)), CalCCA did not request rehearing. This petition is timely filed under California Rule of Court, rule 8.500, subdivision (e)(1). Pursuant to Rule 8.500, subdivision (b)(1), this Court's review is necessary to settle important questions of law.

ISSUES PRESENTED FOR REVIEW

1. In light of the fragmentation of Public Utilities Commission ratemaking into various proceedings outside of formal General Rate Cases, does the Commission's change to the methodology for calculating a component of the Power Charge Indifference Adjustment rate constitute general ratemaking, such that the rule against retroactive ratemaking bars its retroactive

application to rates already being collected under the previously approved methodology?

2. If the Commission changes a rate formula prospectively, purportedly to improve how it measures market conditions and thus satisfies the Commission's obligation to prevent cost shifts between customers, may the Commission also retroactively modify the rate formula's measure of market conditions, reallocating substantial costs between customers, without any finding or evidence that the prior formula actually failed to accurately reflect market conditions?

GROUNDS FOR REVIEW

In Decision 25-06-049, *Decision Adopting Changes to the Calculation of the Resource Adequacy Market Price Benchmark* (June 27, 2025) ("Decision"), the Public Utilities Commission adopted a new method for calculating a rate intended to prevent cost shifts between utility customers and customers of Community Choice Aggregators ("CCAs"). The Decision directed that the new methodology be applied not only prospectively, but retroactively to rates already being collected in 2025 based on forecasts using the previously approved methodology—despite a statutory prohibition on retroactive ratemaking and absent any finding or evidence that the prior methodology actually created a cost shift in 2025. The Decision's retroactive application of the new methodology re-allocated responsibility for more than one billion dollars of costs from utility customers to CCA customers. The Court of Appeal denied CalCCA's petition for review of the Decision in a summary Order.

This Court should grant review of the Order and review the underlying Decision for two reasons.

First, review is warranted to settle an important question of law regarding whether the rule against retroactive ratemaking will continue to fulfill its purpose of ensuring the predictability and stability of rates, given the Decision's weakening of the rule and the significant changes in Commission ratemaking since this Court defined the rule's contours. (Cal. Rules of Court, rule 8.500, subd. (b)(1).) Absent review, the Commission's interpretation would permit the procedural evolution of ratemaking to erode a substantive statutory limitation on the Commission's authority. Because ratemaking increasingly occurs through specialized proceedings rather than traditional General Rate Cases, the Decision would insulate substantial Commission ratemaking from the rule against retroactive ratemaking, undermining the stability and predictability the rule is intended to protect.

The rule against retroactive ratemaking stems from Public Utilities Code section 728.[1] Section 728 states that whenever the Commission determines that a rate is unlawful, it shall set the rate "to be *thereafter* observed and in force." (Emphasis added.) Section 728 limits the Commission to *prospective* action. (*Pacific Telephone & Telegraph Co. v. P.U.C.* (1965) 62 Cal.2d 634, 650.) The purpose of the rule against retroactive ratemaking is to promote the stability and predictability of rates. (*City of Los Angeles v. P.U.C.* (1972) 7 Cal.3d 331, 357 ("*City of Los Angeles I*").) It represents the Legislature's judgment that greater predictability outweighs absolute correctness in rates. (*Ibid.*)

In the 1970s, as Commission ratemaking adapted to volatile fuel prices, this Court defined the scope of the rule against retroactive ratemaking. The Court explained that the rule applies to *general ratemaking*—in which the Commission considers many variables and formulates broad policies to "establish a rate which will permit the utility to recover its cost[s]

[1] All further statutory references are to the Public Utilities Code.

and expenses plus a reasonable return on the value of property devoted to public use"—and not to the ministerial operation of annual adjustment clauses intended to facilitate the recovery of volatile fuel costs. (*Southern Cal. Edison Co. v. P.U.C.* (1978) 20 Cal.3d 813, 818, 828 ("*Edison*").) At that time, general ratemaking occurred in formal proceedings called General Rate Cases. (*Cal. Manufacturers Assn. v. P.U.C.* (1979) 24 Cal.3d 251, 256-57 [describing general rate proceedings].)

Since the 1970s, Commission ratemaking has grown increasingly complex. The general ratemaking functions once performed in General Rate Cases are now conducted in various other proceedings. (See, e.g., A.25-03-010, *Assigned Commissioner's Ruling Consolidating Four Applications and Scoping Memo and Ruling* (July 16, 2025)[2] at p. 3 [addressing cost of capital, capital structure, and rate of return]; D.24-05-028, *Decision Addressing Assembly Bill 205 Requirements for Electric Utilities* (May 15, 2024)[3] at pp. 8-9 [addressing rate design,

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[2] Available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M573/K507/573507615.PDF.

[3] Commission decisions are available at https://docs.cpuc.ca.gov/DecisionsSearchForm.aspx.

including fixed charges]; A.24-05-008, *Assigned Commissioner's Scoping Memo and Ruling* (Aug. 8, 2024),[4] at pp. 2-3 [addressing the reasonableness of risk assessments and mitigation plans].)

In the Decision here, the Commission changed the methodology for calculating the Resource Adequacy Market Price Benchmark ("RA Benchmark"), a component of the Power Charge Indifference Adjustment rate ("indifference adjustment"). Because the indifference adjustment is determined outside of a General Rate Case and is part of a proceeding that also involves costs passed through to customers on which the utility does not earn a rate of return, the Commission concluded that the methodology change was not general ratemaking subject to the rule against retroactive ratemaking. (6:102:APP1365; 6:110:APP1473-74.)[5] The Commission thus directed that the new methodology should be applied retroactively.

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[4] Available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M537/K560/537560212.PDF.

[5] Citations to the Appendix of Exhibits are in the format [Volume]:[Tab]:[Page]. Tabs may be located using the PDF files' bookmarks feature.

The Commission adopted an incorrect, overly narrow definition of general ratemaking. The Decision's change to the methodology for calculating a component of the indifference adjustment involved the consideration of many variables and the formulation of broad policies to establish a rate. The change further concerned the Commission's subjective determinations as to how to measure the market value of certain resources. It bore little resemblance to the ministerial application of annual adjustment clauses based on actual, observed fuel prices this Court exempted from the rule against retroactive ratemaking. The Decision constituted general ratemaking, notwithstanding that it occurred outside of a General Rate Case.

This Court's review of the Decision is necessary to ensure the continuing vitality of the rule against retroactive ratemaking. Absent review, the Commission's weakening of the rule to cover effectively only formal General Rate Cases, combined with the fragmentation of Commission ratemaking, would place broad swaths of Commission ratemaking beyond the rule's reach. Major policy decisions and significant components of rates, representing billions of dollars, could be subject to retroactive change. These changes would threaten the stability of rates on which customers, utilities, CCAs, and other entities rely.

Moreover, without this Court's intervention to clarify that the *substance* of a Commission decision, and not its form or label, determines whether it constitutes general ratemaking, the rule against retroactive ratemaking would be ripe for manipulation. The Commission could avoid the rule by shifting actions, which would otherwise be general ratemaking if part of a General Rate Case, to separate proceedings. This outcome would empower the Commission to undermine a statutory limit on its jurisdiction through procedural manipulations. Review is needed to restore the rule against retroactive ratemaking's ability to preserve stability.

Second, review is warranted to settle an important question of law related to whether the Commission may retroactively re-allocate costs between certain customer classes, in the name of remedying a cost shift, without a finding or evidence that a cost shift was *actually* occurring. (Cal. Rules of Court, rule 8.500, subd. (b)(1).) Absent such support for its actions, the Commission is not impartially administering its statutes; it is picking a winner.

The Commission has a statutory obligation to prevent cost shifts between utility and CCA customers. (§§ 366.2, subd. (a)(4), 366.2, subd. (d)(1), 366.3.) It fulfills that obligation through the indifference adjustment rate. (6:102:APP1340-41.) The RA Benchmark modified in this Decision is a component of the indifference adjustment intended to serve as a proxy for the market value of certain resources in the utility's portfolios. (6:102:APP1341.) If the RA Benchmark does not accurately reflect market value, the ultimate indifference adjustment may be inaccurate, and the rate may shift costs between CCA and utility customers. (6:102:APP1350.)

Here, the Commission determined that the methodology for calculating the RA Benchmark relied on a small sample size and included certain values potentially vulnerable to manipulation. In theory, these factors could result in a benchmark that does not accurately reflect market value. (*Id.*) The Commission thus adopted a new methodology that it determined would generally "improve" the calculation. In addition to applying the new methodology prospectively, the Commission also directed that the new methodology be applied retroactively to rates already being collected under the prior methodology in 2025..

The Decision, however, contained no finding or evidence that the old methodology actually—as opposed to potentially—created inaccurate results for 2025. Because the *actual* accuracy of the RA Benchmark for 2025 implicates whether the Commission fulfilled its statutory obligation to ensure that its rates prevent cost shifts, the Commission erred in failing to make a finding on this material issue and abused its discretion. (§ 1705 [Commission decisions must include findings on all material issues]; *Greyhound Lines, Inc. v. P.U.C.* (1967) 65 Cal.2d 811, 813 [same]; *Securus Technologies, LLC v. P.U.C.* (2023) 88 Cal.App.5th 787, 802-03 [a decision is an abuse of discretion if it is "arbitrary, capricious, or entirely lacking in evidentiary support"].)

The Commission's retroactive application of the new RA Benchmark methodology shifted responsibility for well over one billion dollars of costs from utility customers to CCA customers across the state. (A.25-05-012, *San Diego Community Power and Clean Energy Alliance's Application for Rehearing of Decision 25-*

12-008 (Jan. 5, 2026)[6] at p. 27.) The change contributed to an almost $500 increase in some CCA customers' bills this year alone. (A.25-05-011, *California Community Choice Association's Comments on Proposed Decision* (Dec. 1, 2025)[7] at pp. 4-5.) Absent a finding or evidence that the old methodology actually created inaccurate results, the Commission does not know—and did not find—that these costs were previously improperly allocated. The Decision thus may have created the same sort of cost shift it intended to prevent.

This Court's review is needed to clarify that when a statute requires the Commission to prevent cost shifts, and empirical evidence is available to determine whether a cost shift was occurring, the Commission must make a finding based on that empirical evidence. By relying on potential outcomes rather than empirical findings in such situations, the Commission is not

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[6] Available at https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=593230554.

[7] Available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M588/K915/588915265.PDF.

even-handedly ensuring indifference—it is arbitrarily exercising its regulatory power to shift costs away from favored customers.

CalCCA respectfully requests that the Court grant review on both issues presented.

STATEMENT OF THE CASE

I. The Legislature authorized CCAs to compete with utilities to supply electricity. To ensure equity, the Legislature prohibited cost shifts between CCA and utility customers.

Historically, California's investor-owned utilities had a monopoly over the sale and distribution of electricity in their service territories. Beginning in the 1990s, however, the Legislature deregulated sales of electric generation to consumers. (§ 330, subd. (d).) And in 2002, the Legislature authorized local governments to form CCAs in the utilities' territories. (Stats. 2002, ch. 838 (AB 117), §§ 2, 3.) CCAs are local government organizations that purchase electricity and supply it to their communities. (§ 331.1.) As additional players in the energy market, CCAs promote competition among energy suppliers, enabling lower rates. (See § 330.) CCAs also offer an alternative to profit-driven utilities, allowing customers to choose electricity generation aligned with community values and priorities. (*See*

Stats. 2011, ch. 599 (SB 790), § 2.) Today, 25 CCAs serve more than 15 million California customers across more than 200 cities and counties.

In creating CCAs, the Legislature recognized that utilities had entered into long-term contracts for energy supplies intended to serve their customers—including customers who would later depart for CCAs. The departure of CCA customers would leave fewer utility customers on the hook for the above-market costs of the utilities' generation portfolios, potentially increasing remaining utility customers' rates.

To prevent this outcome, the Legislature required the Commission to ensure that CCA customers' departures would not shift costs between CCA customers and utility customers. (§ 366.2, subd. (a)(4); § 366.3; see also § 365.2; § 366.2, subd. (d)(1).) This requirement is called ratepayer "indifference," because customers' rates must be indifferent to—i.e., unchanged by—customers' departures for CCAs. To prevent cost shifts and maintain indifference, the Legislature allowed utilities to recover certain costs from CCA customers. Those costs include the share of the above-market costs of long-term electricity contracts attributable to CCA customers. (§ 366.2, subd. (f)(2).)

Recognizing that equity required fair treatment of both utility and CCA customers, the Legislature made ratepayer indifference a two-way street. It required not only that *utility* customers "shall not experience any cost increase as a result of" CCA customers' departure, but also that *CCA* customers do "not experience any cost increases as a result of … costs that were not incurred on [their] behalf." (§ 366.3.) The Legislature also required the Commission to reduce CCA customers' rates by "the value of any benefits that remain with" utility customers. (§ 366.2, subd. (g) (emphasis added).)

Electricity prices fluctuate over time. Thus, a long-term contract at a fixed price could be a great deal if electricity prices increase, yielding savings compared to short-term purchases at market prices. In contrast, if electricity prices decrease, a long-term contract could become an albatross. For contracts that utilities executed when CCA customers were still utility customers, indifference requires that CCA customers share in both the burdens of the bad deals and the benefits of the good ones.

II. The Commission employs a complex method for determining rates needed to prevent cost shifts, including calculating proxies for market value known as Market Price Benchmarks.

Each year, as part of the annual Energy Resource Recovery Account ("ERRA") process,[8] the Commission determines the rate changes needed to ensure indifference between CCA and utility customers. (1:1:APP0022.) These changes are known as the Power Charge Indifference Adjustment ("indifference adjustment").

The indifference adjustment compares the utilities' generation procurement costs with the market value of their portfolios of generation assets. (See 1:1:APP0024-25.) The difference between portfolio value and cost is recovered through the indifference adjustment rate. If procurement costs exceed portfolio value, both utility and CCA customers share responsibility for above-market costs incurred on their behalf. In contrast, if portfolio value exceeds procurement costs, both utility and CCA customers get the benefit of the below-market cost of

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[8] An ERRA account is one of several balancing accounts in which a utility may record and balance various procurement costs and collections from ratepayers.

the generation portfolio. If portfolio value greatly exceeds procurement costs, CCA customers could receive a credit on their bills. (*Id.*)

This methodology is applied each year in ERRA Forecast proceedings for each utility. The Commission looks ahead to determine the utility's anticipated revenue requirement for power procurement and what rate changes will ensure indifference in the coming year. (1:1:APP0022-23.) At the same time it looks ahead, the Commission also looks back at what happened during the prior year compared with the previous forecast. The prior forecast is "trued up" to reflect actual procurement costs. (1:1:APP0018.) Any over- or under-collection is credited or debited on the relevant utilities' revenue requirement for the next year. (1:1:APP0018-19.) These changes together—prospective and retroactive—constitute the indifference adjustment.

The Commission determines the market value of the utilities' portfolios of generation assets by setting proxies, called "market price benchmarks," for various components of the portfolios. (1:1:APP0024.) Unlike fuel costs or energy procurement costs, the market value of a portfolio of assets cannot be determined by simply looking at a ledger. Instead, the market price benchmarks—calculated using weighted averages of certain sets of market transactions—are intended to approximate current market value. (*Id.*)

As part of the indifference adjustment, market price benchmarks are forecast each year during the ERRA process and “trued-up” the following year based on “actual” costs and updated proxy values. (*Id.*) Notably, however, the “actual” values set by the market price benchmarks are a misnomer—they depend on the Commission’s subjective choices about which transactions to include in the measurement of market conditions.

III. After shifts in the market for Resource Adequacy benefited CCA customers, the Commission opened a rulemaking to revise the methodology for calculating the RA Benchmark.

This Petition concerns the market price benchmark for Resource Adequacy (“RA”). RA refers to the requirement that utilities have sufficient resources available to ensure reliable electricity service, both locally and system-wide. (§ 380.) The RA Benchmark reflects the estimated market value of resources that satisfy RA requirements. (1:1:APP0024.)

From 2012 to 2023, the indifference adjustment and the method used to calculate it worked out largely in utility customers' favor. That is, procurement costs generally exceeded portfolio value, and so CCA customers paid higher indifference adjustments on their bills. (1:8:APP0108.)

In 2024 and 2025, however, market conditions changed. Uncertainty caused by recent regulatory changes created scarcity in the market for system-wide RA (1:3:APP0059), and prices for assets providing system-wide RA capacity increased dramatically. (1:1:APP0025.) As a result, the market value of the utilities' generation portfolios increased relative to utilities' procurement costs. (*Id.*) And, at least for some CCA customers, the indifference adjustment shifted from a charge to a credit on their bills. (*Id.*) With their own customers facing higher rates and some CCA customers seeing credits, the utilities asserted that the RA Benchmark was causing a cost shift and called for changes to its calculation methodology. (D.24-12-039, *Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue Requirement* (Dec. 23, 2024) at pp. 9-10.)

The Commission has acknowledged that an indifference adjustment credit on CCA customers' bills does not necessarily suggest a cost shift. Rather, "[i]t can accurately reflect" changed market conditions. (1:1:APP0025-26; D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology* (Oct. 19, 2018), at p. 155.)

Nevertheless, in February 2025, the Commission opened proceeding R.25-02-005, in part to modify the RA methodology the utilities had criticized. (1:1:APP0011.) The Commission expedited the proceeding so that updated rates could be implemented as quickly as possible. (1:1:APP0029-30.)

The proceeding centered on a Commission staff report that included various proposals for changing the methodology for calculating the RA Benchmark. (1:2:APP0049; 1:3:APP0057-60.) The staff report focused on the reduced volume of system-wide RA transactions included in the calculation of the 2025 RA Benchmark compared to previous years. Commission staff reasoned that a smaller volume of transactions *could* result in individual transactions having outsized influence on the benchmark, which *could* make the ultimate indifference adjustment subject to manipulation. (1:3:APP0055-56, 59.)

However, the staff report did not include evidence of any such manipulation occurring. Nor did it establish that the sample size under the prior methodology was statistically flawed.

Rather, the staff report speculated about whether certain factors *could conceivably* lead to the calculation methodology being inaccurate. (1:3:APP0055 [speculating, without citing any supporting evidence, that certain transactions "*may* be driven by market power"] (emphasis added); 1:3:APP0057 [observing that certain types of transactions "*may* not reflect genuine market prices"] (emphasis added).) The staff report even acknowledged that normal market forces may have been responsible for the recently increased value of RA resources. (1:3:APP0059 [citing regulatory uncertainty].)

To address its concern about reduced transaction volumes, the staff report proposed, among other things, (1) calculating a single RA Benchmark, rather than three separate benchmarks for three different types of RA assets; and (2) expanding the set of transactions used to calculate the RA Benchmark by including transactions for system-wide RA assets from more than just the most recent year. (1:3:APP0057-60.) The latter proposal diverged from D.18-10-019 and D.19-10-001, which had determined that transactions from the most recent year would provide the most accurate picture of *current* market conditions for system-wide RA. (D.18-10-019, *supra*, at p. 73; D.19-10-001, *Decision Refining the Method to Develop and True Up Market Price Benchmarks* (Oct. 17, 2019) at p. 21.) The staff report also proposed excluding various sets of transactions—e.g., transactions between affiliated entities, like parent and subsidiary companies—that *might* not reflect market rates. (1:3:APP0060-61.)

IV. The Commission adopted a new methodology for calculating the RA Benchmark and directed that it be applied not only prospectively but retroactively to rates already being collected in 2025 under the old methodology.

On June 27, 2025, the Commission issued the Decision. (6:102:APP1335.) The Decision adopted the staff report's proposals for changing the original methodology used to calculate the RA Benchmark. (6:102:APP1367-69.)

Significantly, in addition to directing the utilities to apply the new method prospectively, the Decision also directed that the new methodology should be applied retroactively to true-up the 2025 forecasts approved under the prior methodology. (6:102:APP1364-66.) For those rates, the Decision changed the methodology mid-stream, requiring a true-up against an entirely different set of figures from those used in the forecast. (See *id.*)

The Commission stated that this retroactive application was necessary to comply with the statutory indifference mandate. (*Id.*) But the Commission did not cite any concrete evidence that the transactions included in the prior RA Benchmark calculation methodology did not *actually* reflect 2025 market conditions, and thus that the old methodology did not actually result in ratepayer indifference in 2025. It likewise did not demonstrate that the number of transactions relied upon under the prior methodology was statistically flawed.

V. CalCCA petitioned for review of the Commission's decision.

CalCCA applied for rehearing of the Decision. (6:104:APP1374.) The application explained that retroactively applying the new methodology violated the rule against retroactive ratemaking. (6:104:APP1393-1411.) That statutory rule states that the Commission's authority extends only to *prospective* ratemaking. (§ 728.) The Decision had dismissed this concern, asserting that the rule against retroactive ratemaking applies only to "general" rates, and that this proceeding did not set general rates. (6:102:APP1365.) CalCCA explained, however, that the Commission's complex, policy-laden redesign of the method used to calculate the indifference adjustment constituted general ratemaking. (6:104:APP1393-1409.)

CalCCA also explained that the Commission's decision to apply the new methodology retroactively was not supported by its findings and constituted an abuse of discretion. The Decision lacked an affirmative finding and evidence that the old methodology actually failed to reflect market conditions in 2025 and thus failed to ensure indifference. (6:104:APP1413-14.)

The Commission denied CalCCA's application. (6:110:APP1468 [(D.25-10-061, *Order Denying Rehearing of Decision 25-06-049* (Oct. 31, 2025)].) CalCCA timely filed a Petition for Writ of Review of D.25-06-049 and D.25-10-061. The Court of Appeal summarily denied the petition on June 25, 2026.

ARGUMENT

I. Review is necessary to ensure the continued vitality of the rule against retroactive ratemaking as an important tool to preserve the stability of rates.

A. The Courts defined the rule against retroactive ratemaking—and its exception—to balance stability and predictability in rates with flexibility to address volatility.

Public Utilities Code section 728 prohibits the Commission from engaging in retroactive ratemaking. Under this section, if the Commission investigates approved rates—including not only the rates themselves, but also "rules" or "practices" affecting those rates (§ 728)—and finds them unreasonable, its ability to grant relief is limited to *prospective* action. The Commission lacks authority to roll back rates that have already been approved. (*Pacific Telephone & Telegraph Co.*, supra,62 Cal.2d at p. 650.)

The prohibition on retroactive ratemaking promotes stability in ratemaking for the benefit of both utilities and ratepayers. (*City of Los Angeles I*, *supra*, 7 Cal.3d at p. 357.) The rule represents a determination that the value of predictability "outweighs the value of being able to correct for decisions that in hindsight may appear unsound." (*P.U.C. of State of Cal. v. F.E.R.C.* (D.C. Cir. 1990) 894 F.2d 1372, 1383 ["[P]arties in the industry need to be able to rely on the finality of approved rates"]; *City of Los Angeles I*, *supra*, 7 Cal.3d at p. 357 ["[A]bsolute equity must sometimes give way to the greater overall good, including the demands of certainty and efficiency."].) This Court has acknowledged that at times, the prohibition on rolling back unreasonable rates may appear unjust. But it has directed such arguments to the Legislature rather than allow the Commission to violate the prohibition. (*City of Los Angeles I*, *supra*, 7 Cal.3d at pp. 356-57.)

In construing section 728, this Court has described an important but limited exception to the rule against retroactive ratemaking intended to allow the Commission to address unpredictable swings in prices. In a series of cases in the 1960s and 1970s, the Court held that the rule against retroactive ratemaking applied only to "general ratemaking." (See, e.g., *Edison*, *supra*, 20 Cal.3d at pp. 816, 828-30.) In contrast, the rule did not apply to the operation of annual fuel adjustment clauses designed to quasi-automatically adjust utility rates to account for divergences in fuel prices from forecasts, which was *not* general ratemaking. (*Ibid*.)

The Court defined general ratemaking, to which the rule against retroactive ratemaking applied, as a decision-making process involving the consideration of many variables and formulation of broad policies to "establish a rate which will permit the utility to recover its cost[s] and expenses plus a reasonable return on the value of property devoted to public use." (*Id.* at pp. 818, 828.) At the time, this decision-making process occurred in specialized, formal rate proceedings known as General Rate Cases. (*Cal. Manufacturers Assn.*, *supra*, 24 Cal.3d at pp. 256-57.)

In defining general ratemaking, *Edison* extensively discussed *City of Los Angeles v. Public Utilities Commission* ((1975) 15 Cal.3d 680 ("*City of Los Angeles II*")). (*Edison*, 20 Cal.3d at pp. 826-29.) In the earlier case, the Court held that the Commission could address fluctuating federal tax expenses by adopting an annual adjustment method of determining rates (*City of Los Angeles II*, *supra*, 15 Cal.3d at pp. 684, 695)—the sort of quasi-automatic adjustment *Edison* distinguished from general ratemaking. (*Edison, supra*, 20 Cal.3d at p. 828.) The annual adjustment method automatically changed the rates charged to customers based on a formula that compared forecast costs to actual tax expenses. (*City of Los Angeles II*, *supra*, 15 Cal.3d at pp. 691-92.) The Court held that the Public Utilities Code allowed the Commission to adopt such formulas and fixed rules as part of their rates, reasoning that plugging in the numbers each year based on "empirical data" was "substantially ministerial." (*Id.* at p. 692.)

Relevant here, the Court held that section 728 did not require a full hearing each time the Commission applied the annual adjustment clause, even though that application changed customers' rates. Such a hearing "serves no purpose when the only business at hand is the application of a mathematical formula to a figure definitively established by reference to the utilities' books." (*Id.* at p. 697.) The Court contrasted the *adoption* of the formula with its *annual application*, stating: "[t]he legislative purpose behind section 728 is better served by a plenary consideration of the advantages and disadvantages of an annual adjustment clause than by a yearly charade attendant to its application." (*Ibid.*)

City of Los Angeles II referred to ratemaking requiring a hearing, rather than to *general ratemaking*. But section 728 speaks in similar terms, referring not to general ratemaking but to Commission decisions "after a hearing." Courts have interpreted section 728's references to decisions requiring hearings to refer to decisions that constitute general ratemaking. (*Edison*, *supra*, 20 Cal.3d at p. 816.) *City of Los Angeles II* should be similarly understood. It thus clarifies that the annual application of a fuel adjustment clause does not constitute general ratemaking.

Edison built on *City of Los Angeles II*. It likewise concluded that annual application of a fuel adjustment clause intended to recover actual fuel costs was not general ratemaking, reasoning that the operation of fuel adjustment clauses is "essentially ministerial," and the resulting rate changes do not require a hearing within the meaning of section 728. (20 Cal.3d at pp. 828-29.) The Court further reasoned that, because the application of a clause intended to recover actual costs is not general ratemaking, ordering refunds of amounts collected in excess of actual costs does not violate the rule against retroactive ratemaking. (*Id.* at pp. 829-30.) *Edison* emphasized that the refunds relied on "empirical data" related to actual fuel costs "definitively established by reference to the utilities' books," (*Id.* at pp. 828-29), and not to more nebulous, policy-laden issues.

The adjustment clauses approved in *Edison* and *City of Los Angeles II* are intended to allow the Commission to approve one-off rate changes to account for extraordinary charges occurring within the scope of a previously designed and approved rate methodology. (See *Ponderosa Telephone Co. v. P.U.C.* (2011) 197 Cal.App.4th 48, 63-64 [stating that *Edison* involved such "extraordinary" charges].) By defining general ratemaking to exclude such changes, and so limiting the scope of the rule against retroactive ratemaking, the Court struck a balance between the stability afforded by the rule and flexibility for the Commission to deviate from forecasted rates outside of formal General Rate Case proceedings. (*Edison*, *supra*, 20 Cal.3d at p. 816 [describing the limits on the rule as necessary to preserving its status as "a useful principle of regulatory law"].)

B. The Commission adopted an erroneous interpretation of "general ratemaking" that prioritizes form over function.

In the Decision, the Commission adopted a change to its methodology for calculating the RA Benchmark, a component of the indifference adjustment rate, and directed that the new methodology be applied retroactively to rates already being collected under the previously approved methodology. The

Commission, however, concluded that its Decision did "not set general rates," and thus that the rule against retroactive ratemaking did not apply. (6:102:APP1365.) In reaching this conclusion, the Commission reasoned that the indifference adjustment is determined as part of a proceeding involving costs passed through to ratepayers, like the fuel costs and fuel adjustment clause at issue in *Edison*, without opportunity for the utility to earn a rate of return. Those costs, the Commission said, have always "been subject to true-up based on actual costs." (6:110:APP1473-74.) The Court of Appeal declined to review the Decision. (Order.)

The Decision incorrectly concludes that the change to the methodology for calculating the RA Benchmark is not general ratemaking. In focusing on the type of proceeding and costs at issue, the Decision improperly prioritizes form over function and adopts an inappropriately narrow definition of general ratemaking. Contrary to the Decision, the change to the RA methodology constituted general ratemaking because the Decision bore all of the substantive characteristics of general ratemaking, regardless of the type of proceeding in which it occurred and the type of costs at issue.

In holding that the decision to refund costs associated with a fuel adjustment clause did not constitute general ratemaking, *Edison* contrasted "the essentially 'ministerial' operation of … [the] adjustment clause[ ]" and "true ratemaking." (*Edison*, *supra*, 20 Cal.3d at pp. 826-29.) The latter, *Edison* explained, involves the consideration of many variables and the formulation of broad policies to set a rate which allows the utility to recover its costs and a reasonable return on investment. (*Edison*, *supra*, 20 Cal.3d at pp. 826-29.) Here, the Decision's change to the methodology for calculating the RA Benchmark was not ministerial or a "matter of simple arithmetic." (See *id.* at p. 818 [describing operation of a fuel adjustment clause].) It involved *designing* the methodology, including "plenary consideration of the advantages and disadvantages" of various potential methods for determining the value of the utilities' generation portfolios. (See *City of Los Angeles II*, *supra*, 15 Cal.3d at p. 697.)

In evaluating RA Benchmark calculation methodologies, the Commission considered many variables, including: whether and how RA markets had shifted (1:1:APP0025); how those shifts impacted RA transactions (*id.*); whether a smaller RA transaction volume required a change in methodology (6:102:APP1352); what constitutes a "market-based transaction," and which types of transactions should comprise the RA Benchmark calculation set (6:102:APP1357-58); how many years of transactions should be included (6:102:APP1356); and whether different sub-sets of transactions should be evaluated separately or together (6:102:APP1348-56). The Commission's consideration and resolution of these variables implicated broad policy concerns, including how to best measure the market value of the utilities' generation portfolios, and whether the RA Benchmark methodology was ultimately ensuring ratepayer indifference. (6:102:APP1369.)

These concepts and policy questions were unlike anything at issue in *Edison*. In *Edison*, the Court relied heavily on the fact that the refunds were calculated based on "empirical data" and actual costs for fuel that could be "definitively established by reference to the utilities' books." (*Edison*, *supra*, 20 Cal.3d at pp. 828-29.) In contrast, the methodology here involved the subjective determination of market *value*, a concept that cannot be determined by reference to the utilities' ledgers. As opposed to an actual cost, the RA Benchmark is a Commission-determined proxy for the value of a portion of the utilities' generation portfolios. By revising the methodology for determining the RA Benchmark, the Commission did not simply compare forecasted costs to actual costs, as in *Edison*; it revised its definition of portfolio market value. This sort of determination is typical of general ratemaking and a far cry from the ministerial application of adjustment clauses.

The fact that the Decision involved "pass-through" costs and occurred outside of a General Rate Case does not remove it from general ratemaking. General ratemaking involves consideration of "cost[s] and expenses plus a reasonable return on the value of property devoted to public use." (*Edison*, *supra*, 20 Cal.3d at p. 818.) Both return on investment *and costs* are included in the mix. (*Southern Cal. Gas. Co. v. P.U.C.* (1979) 23 Cal.3d 470, 474 ["Rates of a publicly regulated utility are based on two components: (1) the utility's operating expenses … and (2) a fair return on its investment, which is found by multiplying its authorized rate of return by the value of property devoted to public use (rate base)."].) Section 728 says nothing about whether the rate involves pass-through costs or investments on which the utility has the opportunity to earn a profit.

Moreover, general ratemaking occurs outside of General Rate Cases. For example, factors like the utilities' rate of return are set in proceedings separate from the utilities' General Rate Cases. (A.25-03-010, *supra*, at p. 3; see also *Southern Cal. Gas Co. v. P.U.C.* (1979) 23 Cal.3d 470, 480, 483-84 [adjusting rate of return outside of a General Rate Case].) The Legislature has likewise acknowledged that some rates may be set either within or outside of General Rate Cases. (§ 727.5, subd. (2)(D) [allowing certain applications involving water rates to be resolved in a triennial general rate case or outside of one].)

Here, the indifference adjustment is a general rate, and the change to its design at issue constituted general ratemaking even though it occurred outside of a General Rate Case. In a General Rate Case, the Commission determines the utility's revenue requirement, fixes the rate, and allocates the rate among customers. (*Cal. Manufacturers Assn.*, *supra*, 24 Cal.3d at p. 2557.) In formulating the indifference adjustment, the Commission performed each of these steps. It established a revenue requirement, including determining eligible costs (See, e.g., D.18-10-019, *supra*, at p. 157 ["Including the costs of pre-2022 Legacy [Utility-Owned Generation] within the [indifference adjustment] is consistent with AB 117 and SB 350."].); it allocated the revenue among customer classes—the indifference adjustment determines whether CCA or utility customers are responsible for certain costs (see § 366.2, subds. (f), (g)); and it turned the allocated revenues into a rate set on a usage basis. Because the indifference adjustment is a general rate, notwithstanding that it is set outside of a General Rate Case, changes to its design constitute general ratemaking.

C. Changes in Commission ratemaking, combined with the Commission's formalistic interpretation of "general ratemaking," threaten the stability and predictability of rates.

Since the 1970s, ratemaking at the Commission has changed significantly. General rates are now determined across many open ratemaking proceedings that modify revenue requirements and change cost allocation and rate design. Although this shift in the Commission's operations accelerated in recent decades, it was beginning even in the late 1970s. One year after *Edison,* in *California Manufacturers Association v. Public Utilities Commission*, the Court took up the question of whether the Commission could make policy decisions in smaller contexts outside of general rate proceedings. (*Supra,* 24 Cal.3d at p. 256.)

The Court held that such "offset" proceedings were acceptable forums for policy decisions concerning how to allocate certain costs among customer groups. (*Id.* at p. 257.) The Court clarified that *Edison*'s characterization of "true ratemaking" as involving policy decisions did not mean that policy-making could occur *only* in general rate proceedings. (*Id.*)

Significantly, however, *California Manufacturers Association* did not involve general ratemaking. Rather, the policy decisions over cost allocation at issue in that case concerned adjustments to offset higher gas costs. (*Id.* at p. 255.) Like the costs in *Edison*, the gas costs were *actual* costs, readily verifiable by reference to historical data. But because *California Manufacturers Association* did not involve general ratemaking, it did not hold that general ratemaking occurs *only* in a general rate proceeding. As far as CalCCA is aware, no case has such a holding.

The Decision, however, threatens to severely limit the utility of the rule against retroactive ratemaking. By applying an overly restrictive conceptualization of "general ratemaking" that would effectively limit its scope to General Rate Cases, the Decision would place vast swaths of Commission ratemaking beyond the reach of section 728. Following the Decision, even significant policy decisions and shifts in direction could be applied retroactively provided that the proceedings were not part of a utility's General Rate Case or involved only pass-through costs.

This weakening of the rule against retroactive ratemaking would have a significant destabilizing impact. CCAs, for example, rely on existing regulatory frameworks to make budgeting decisions, plan operations, and set rates for customers. (See 5:87:APP1183-84.) The Decision's retroactive application has upset this budgeting and planning and caused the CCAs to scramble to prevent their customers from suffering severe rate shock from unexpected costs. (A.25-05-012, *supra*, at p. 27.)

Review is necessary to clarify that general ratemaking depends on the substance of the Commission's decision-making, not on the proceeding in which it occurs. This Court's review is needed to maintain the rule against retroactive ratemaking as a useful tool to protect the stability of rates.

II. Review is needed to ensure that the Commission does not cut corners in order to pick winners and losers, but rather does the work required to allow it even-handedly to ensure indifference.

A. The Commission's findings and evidence in support of a prospective change to the methodology for calculating indifference did not adequately support the change's retroactive application.

All Commission decisions must contain "separately stated, findings of fact and conclusions of law by the commission on all issues material to the order or decision." (§ 1705.) A decision that is not supported by the findings is subject to reversal. (§ 1757; § 1757.1.) "Every issue that must be resolved to reach [the] ultimate finding is material to the order or decision." (*Greyhound Lines, Inc.*, *supra*, 65 Cal.2d at p. 813.) To support the decision, the findings must be sufficient to "bridge the analytic gap between the raw evidence and ultimate decision or order." (*Sky Posters Inc. v. Dept. of Transportation* (2022) 78 Cal.App.5th 644, 668, quoting *Topanga Assn. for a Scenic Community v. County of Los Angeles* (1974) 11 Cal.3d 506, 515.) To bridge such a gap, the findings must address the specific substantive issue motivating the agency's decision; findings in the ballpark that do not connect the dots between the evidence and ultimate decision are not sufficient. (*Sky Posters Inc.*, *supra*, 78 Cal.App.5th at p. 668.) The Commission also abuses its discretion if it entirely lacks evidentiary support or fails to demonstrate a rational connection between factors relevant to its decision and the choice made. (*Securus Technologies, LLC*, *supra*, 88 Cal.App.5th at pp. 802–03.)

Here, the Commission's decision to apply the new indifference methodology retroactively was premised on the assumption that the 2025 rates produced by the old methodology were inaccurate, based in part on the number of transactions reflected in the RA Benchmark. (See, e.g., 6:102:APP1353 ["We are persuaded that the volume of transactions included in the 2025 … forecast leads to an [RA Benchmark] that does not represent the value of the portfolio and … do[es] not uphold the indifference mandate. Immediate changes are required."].) The accuracy of the 2025 rates under the old methodology was therefore an issue "material to the order or decision." (See *Greyhound Lines, Inc.*, *supra*, 65 Cal.2d at p. 813.) Because the Commission made no finding and had no evidence that the number and type of transactions actually resulted in an inaccurate RA Benchmark and, therefore, that the 2025 rates were actually inaccurate, its findings do not support the Decision and it abused its discretion.

The Commission's findings, based on concerns that the old methodology could *potentially* lead to inaccurate RA Benchmarks, arguably sufficiently supported prospective application of a new methodology. For example, the Commission determined that the old methodology relied on a smaller volume of transactions, which *could* be less accurate than a larger sample. (6:102:APP1350, 52-53, 67-68.) The Commission also concluded that affiliate, swap, and sleeve transactions *might* not reflect market values and were vulnerable to manipulation. (See 1:1:APP0031-32; 6:102:APP1358-59; 6:102:APP1360.) These findings of potential inaccuracy arguably support *prospective* application of the new methodology, because the question of whether the new methodology will ensure indifference in the future is a theoretical question. (*Cal. Community Choice Assn. v. P.U.C.* (2024) 103 Cal.App.5th 845, 863, emphasis added ["Because the Commission's focus is not on recovering actual costs or penalizing past deficiencies but *rather on preventing this type of cost shifting in the future*, it is not necessary that the

Commission quantify the cost shift that occurred in September 2022."].)

But whether *retroactive* application of the new methodology to the 2025 Benchmark ensured indifference—i.e., by accurately reflecting market prices—is an empirical question. The Commission had *actual* transaction data to scrutinize as to the 2025 Benchmark, and so the question of whether the old RA Benchmark accurately reflected market prices could only be definitively answered by resort to that data. The material issue regarding whether retroactive application was necessary to ensure indifference was thus whether the old RA Benchmark was *actually* inaccurate, not whether it might potentially be inaccurate. (See *Cal. Manufacturers Assn., supra*, 24 Cal.3d at p. 259 [the findings must support the Commission's asserted justification for its decision]; *Cal. Community Choice Assn.*, *supra*, 103 Cal.App.5th at p. 863.)

The findings requirement for Commission decisions requires specific support tailored to each material issue. For example, in *California Manufacturers Association*, the Commission changed its methodology for spreading rate increases among utility customers, justifying the change by insisting that restructured rates were necessary to conserve natural gas resources. (24 Cal.3d, *supra*, at pp. 255-56.) The Court annulled the Commission's decision, holding that the Commission's "findings on the material issues [were] insufficient" because the Commission made no specific finding that the new methodology would actually result in more conservation than alternative approaches. (*Id.* at p. 259.) Although the Commission "made findings relating to the benefits" of its proposed methodology, "the rate spread order c[ould not] be justified by those matters alone." (*Id.* at p. 260.)

As the Commission in *California Manufacturers* could not justify its rate spread order with general findings about the importance of conservation, the Commission here cannot justify retroactive application with findings about lower transaction volumes and vulnerabilities *potentially* creating inaccuracies, without ever finding that those features *actually* produced inaccurate rates in 2025. The Commission made no such finding.

For example, the Commission presumes that lower transaction volumes mean that the 2025 forecast RA Benchmark did not accurately represent portfolio value. (6:102:APP1353.)

But it never establishes that conclusion with evidence.[9] Such conclusory findings are inadequate. (*Geffner v. Bd. of Psychology* (2024) 100 Cal.App.5th 19, 35; *Asociacion de Gente Unida por el Agua v. Central Valley Regional Water Quality Control Bd.* (2012) 210 Cal.App.4th 1255, 1281.) Indeed, a small sample can still be representative of the overall population, (Maurice A. Geraghty, Inferential Statistics and Probability - A Holistic Approach § 4.4.1), and the Commission never bridges the gap between the possibility that lower transaction volumes might result in a less accurate RA Benchmark and the required empirical conclusion that they actually did so.

Similarly, while the Commission criticized the inclusion of swap, sleeve, and affiliate transactions in the old methodology as being vulnerable to manipulation (6:102:APP1365, 67-68), the Commission found only the "*potential* for such manipulation."

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[9] The Decision suggested that greater price increases in the category of system RA transactions from the past year compared to a supposedly "premium" category of local RA transactions from *several* past years suggested flaws in the methodology. (6:102:APP1351-52.) But the Decision itself admitted that the most recent year included significantly increased prices. (6:102:APP1351.) The unequal comparison does not show that the price increases did not accurately reflect market conditions.

(6:102:APP1358-59, emphasis added.) Indeed, the Commission concluded that the record "does not support a finding that purposeful manipulation has taken place." (*Id.*; see also 6:102:APP1358 [noting that "[s]leeve transactions may reflect market prices."].) The Commission again failed to answer an empirical question—whether manipulation occurred—with an empirical finding, based on empirical evidence.

B. Review is needed to prevent the Commission from picking winners and losers where statutes require even-handedness.

The Commission has a statutory duty to ensure that its rates hold both CCA customers and utility customers indifferent to customers' departures for CCAs. (§ 366.2, subds. (a)(4), (d)(1); § 366.3; see also § 365.2; *Cal. Community Choice Assn.*, *supra*, 103 Cal.App.5th at p. 858 [the indifference statutes "charge[ ] the Commission with ensuring that [CCA expansion] … will not result in cost shifting between CCA and non-CCA customers."].) As the Commission stated in 2018, "the Commission must ensure equity on both sides of the departing load transaction, that is, for [CCA customers] as well as remaining" utility customers. (D.18-10-019, *supra*, at pp. 6-7.)

When the Commission *prospectively* changes the indifference adjustment based on what methodologies theoretically will best reflect market prices in the future, the winners and losers of that prospective change are largely unknowable. Future market trends may interact with the new methodology in ways that favor CCA customers *or* utility customers, and the impacts are difficult to determine.

In contrast, when the Commission changes the indifference adjustment retroactively, the impacts to CCA customers and utility customers are readily calculated. Here, for example, the old methodology would have led many CCA customers to receive a credit on their bills for the indifference adjustment. In contrast, the new methodology sharply increased CCA customers' indifference adjustment rates. The new methodology, along with other factors increasing indifference adjustment rates, caused some CCA customers' average 2026 indifference adjustments to increase by 455% from the prior year. (A.25-05-011, *supra*, at p. 4.) Across the three major electric utilities, the new RA Benchmark methodology resulted in impacts of well over one billion dollars of increased costs to CCA customers. (A.25-05-012, *supra*, at p. 27.) That increase was the primary factor responsible for increasing some customers' bills by up to $492 in 2026 alone. (A.25-05-011, *supra*, at pp. 4-5.)

The Commission knew that the new methodology would drastically shift cost responsibility from utility customers to CCA customers. (5:86:APP1168.) What the Commission did not know based on the evidence before it, and what it did not find, is whether those retroactively shifted costs were *actually* necessary to preserve indifference because the old methodology was *actually* inaccurate. By relying on findings of potential inaccuracy instead of empirical findings about the *actual* data to support its retroactive application of the new methodology, the Commission did not determine whether a cost shift was actually occurring in 2025, and it did not fulfill its statutory obligation to ensure indifference. Instead, by retroactively changing the methodology in the absence of a finding that the old methodology actually offended indifference, the Commission exercised regulatory power to pick a winner.

Review is needed to clarify that when a statute requires the Commission to ensure *actual* indifference, the Commission must look at—and make a finding regarding—*actual* empirical evidence regarding indifference when such evidence is available.

Absent these steps and evidentiary support, the Commission's decision is not supported by the findings and constitutes an abuse of discretion. (See *Cal. Manufacturers Assn., supra*, 24 Cal.3d at p. 259; *Securus Technologies, LLC*, *supra*, 88 Cal.App.5th at pp. 802-03.) Importantly, if the Court does not hold the Commission to its obligation to perform this work, the Commission may continue to pick winners and losers. Such a result would offend the indifference statutes' requirement that the Commission ensure equity for both CCA and utility customers.

The requirement that the Commission support its decision with findings on all material issues is designed to avoid such arbitrary outcomes. (See, e.g.*, Cal. Motor Transportation Co. v. P.U.C.* (1963) 59 Cal.2d 270, 274 ["Findings on material issues can … help the commission avoid careless or arbitrary action."].) Thus, review is also necessary to ensure that the findings requirement is properly enforced.

CONCLUSION

For the reasons described above, CalCCA respectfully requests that this Court grant review on the questions presented.

DATED: July 6, 2026

SHUTE, MIHALY &
WEINBERGER LLP

By: */s/ Aaron M. Stanton*

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CERTIFICATE OF COMPLIANCE

Pursuant to California Rules of Court, Rule 8.504, subdivision (d)(1), I hereby certify that the text of this Petition for Writ of Review contains 8,282 words, as determined by the word processing software used to prepare this brief and exclusive of this certification and the other materials not included under Rule 8.504, subdivision (d)(3).

DATED: July 6, 2026

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WEINBERGER LLP

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EXHIBIT A

IN THE

Court of Appeal of the State of California

IN AND FOR THE

THIRD APPELLATE DISTRICT

CALIFORNIA COMMUNITY
CHOICE ASSOCIATION,
Petitioner,
v.
PUBLIC UTILITIES COMMISSION,
Respondent;
PACIFIC GAS AND ELECTRIC
COMPANY et al.,
Real Parties in Interest.

C105174
Sacramento County
Nos. 2506049, 2510061

BY THE COURT:

The application of Commercial Energy of Montana, Inc., et al., for leave to file an amici curiae brief in support of petitioner is denied.

The petition for review is denied.

Renner

RENNER, Acting P.J.

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cc: See Mailing List

IN THE

Court of Appeal of the State of California

IN AND FOR THE

THIRD APPELLATE DISTRICT

MAILING LIST

Re: California Community Choice Association v. Public Utilities Commission
C105174
Sacramento County Super. Ct. Nos. 2506049, 2510061

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PROOF OF SERVICE

At the time of service, I was over 18 years of age and **not a party to this action**. I am employed in the County of San Francisco, State of California. My business address is 550 California Street, Suite 1200, San Francisco, CA 94104.

On July 6, 2026, I served true copies of the following document(s) described as:

PETITION FOR REVIEW

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I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on July 6, 2026, at San Francisco, California.

/s/ Frederick Ezekiel R. Pasco
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In The Supreme Court Of California

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

Application of Pacific Gas and Electric Company for Approval of Its Billing Modernization Initiative (U 39 M)	Application No. 24-10-014

JOINT MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 M) AND THE JOINT COMMUNITY CHOICE AGGREGATORS FOR ADOPTION OF SETTLEMENT AGREEMENT

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of Its Billing Modernization Initiative (U 39 M)	Application No. 24-10-014

JOINT MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 M) AND THE JOINT COMMUNITY CHOICE AGGREGATORS FOR ADOPTION OF SETTLEMENT AGREEMENT

I.! INTRODUCTION

Pursuant to Rule 12 of the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E) and WestLight Energy,[1] Ava Community Energy, Central Coast Community Energy, Marin Clean Energy, City of San José, Silicon Valley Clean Energy, and Sonoma Clean Power Authority (collectively, the Joint CCAs, and together with PG&E, the Settling Parties) hereby submit for Commission review and approval a Partial Settlement Agreement (the Partial Settlement Agreement) resolving the issues contested by the Joint CCAs in the !"##$%& (%*!) +!, ' &#&- ' . !" */ !0 $1&(2%&3) 4 #' *5!+) 2!"##2) 6' $!) +!7(. !8 %$%*9! :) / 12*%' (%*!7*%&%(%1 (BMI Application). This Agreement was entered into by the Settling Parties as a compromise in order to minimize the time, expense, and uncertainty of further regulatory proceedings between the Settling Parties in the BMI Application. Because this Agreement is reasonable in light of the whole record, consistent with law, and in the public interest, the Settling Parties urge the Commission to adopt it without modification.

II.! BACKGROUND

A.! Procedural Background

In June 2021, PG&E initially sought approval for a billing system upgrade project as part of its 2023 General Rate Case (GRC) Application (A.) 21-06-021 to modernize its billing systems. However, in Decision (D.) 23-11-069, the California Public Utilities Commission (Commission) found that PG&E's 2023 GRC application lacked sufficient detail to support the

[1] Formerly Peninsula Clean Energy Authority.

forecasted cost of its billing system upgrade project and authorized PG&E to file a separate application that includes additional information.[2]

PG&E filed its BMI Application (A.24-10-014) and Initial Testimony on October 23, 2024. PG&E's Application requested approximately $761.3 million in funding for 2023-2030 to upgrade and replace PG&E's aging billing systems. On November 25, 2024, Peninsula Clean Energy Authority filed a protest. On December 5, 2024, PG&E filed a reply to protests and responses. The Commission issued its Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo) on March 27, 2025. The Scoping Memo categorized the proceeding as a ratesetting proceeding, set forth the issues to be determined in the proceeding, determined that evidentiary hearings were needed, adopted a schedule for the proceeding, and addressed other administrative issues.

On June 25, 2025, Ava Community Energy, Central Coast Community Energy, the City and County of San Francisco, acting by and through its Public Utilities Commission, Marin Clean Energy, City of San José, Silicon Valley Clean Energy, and Sonoma Clean Power Authority filed a motion for party status. The Administrative Law Judge (ALJ) granted that motion by email ruling on June 30, 2025. Joint CCAs and other parties to the proceeding submitted Direct Testimony on June 30, 2025.[3]

Joint CCAs recommended a complete disallowance of the Customer Care and Billing (CC&B) stage of the BMI. Joint CCAs further recommended a number of specific changes related to bill presentation, data quality and access, reporting, rate implementation projects, community choice aggregator (CCA) service fee updates, and PG&E's proposed functionalization of the BMI revenue requirement. PG&E and Joint CCAs submitted Rebuttal Testimony on July 30, 2025.[4] In its Rebuttal Testimony, PG&E updated its cost forecast to approximately $756.4 million.

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[2] D.23-11-069, pp. 546-550.

[3] Note that the City and County of San Francisco, acting by and through its Public Utilities Commission (CleanPowerSF), joined in the Joint CCAs' June 30, 2025, Direct Testimony submission. However, CleanPowerSF is not included in the group of Joint CCAs as defined in this Partial Settlement Agreement.

[4] Note that CleanPowerSF joined in the Joint CCAs' July 30, 2025, Rebuttal Testimony submission. However, CleanPowerSF is not included in the group of Joint CCAs as defined in this Partial Settlement Agreement.

On March 17, 2026, PG&E filed Supplemental Testimony describing material changes to the projected timeline for the BMI, as directed by the ALJ. The Commission held an evidentiary hearing on June 8 and June 9, 2026.

B.! Settlement Process and Compliance with Rule 12.1

The parties to the proceeding met on August 14, 2025, September 5, 2025, and January 14, 2026, to discuss a potential settlement of the proceeding, but did not reach a settlement agreement. PG&E and the Joint CCAs regularly met separately in ongoing settlement negotiations. The parties filed Joint Case Management Statements on August 20, 2025, January 30, 2026, and May 7, 2026, which each indicated that no settlement had been reached as of the filing date. On June 5, 2026, the Settling Parties reached an agreement in principle. On June 10, 2026, PG&E gave notice to all parties of a settlement conference to be held on June 19, 2026, pursuant to Rule 12.1(b). PG&E, Joint CCAs, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) and Direct Access Customer Coalition (DACC) participated in the June 19, 2026 Settlement Conference. On June 19, 2026, following the settlement conference, PG&E provided an email summary of the agreement in principle to the parties not in attendance, which included Small Business Utility Advocates, The Utility Reform Network, and Leapfrog Power, Inc.

III.! SUMMARY OF SETTLING PARTIES' POSITIONS IN TESTIMONY

A.! PG&E's Positions

The BMI will upgrade and replace PG&E's aging billing systems, which are critical to serving the more than six million PG&E customers in areas of billing, customer service, and customer data management. PG&E's BMI will ultimately move customers to a single unified customer care, service order, metering, and billing system, designed to handle the complexities and challenges associated with a regulated utility in the California marketplace, while minimizing disruption and system instability during the transition. PG&E proposes a three-stage approach to stabilize and upgrade the billing systems: The first stage addresses PG&E's electric complex billing customers through the Billing Cloud Services (BCS) solution and replacement of the Advanced Billing System (ABS), which was developed in-house in the 1990s. The second stage will update the outdated version of Oracle Utilities Customer Care and Billing (CC&B) that PG&E currently uses, version 2.4, to version 25.4 (now called version 25.4). The third stage will complete the implementation of a modernized billing system by replacing all billing components with Oracle's more advanced Customer to Meter (C2M) product and consolidating the electric BCS and gas ABS customers into one system.

PG&E's BMI Application (as updated in Rebuttal Testimony) includes the 2023-2030 expense and capital expenditure forecasts shown below:

SUMMARY OF FORECASTED CAPITAL AND O&M COSTS (2024-2030)
(MILLIONS OF 2023 NOMINAL DOLLARS)[5]

Line No.	Stage	Capital Cost	O&M Expense	Total
1	BCS	$124.6	$2.7	$127.3
2	CC&B 25.4	119.0	8.6	127.6
3	C2M	425.6	75.9	501.5
4	Total	$669.2	$87.2	$756.4

SUMMARY OF CAPITAL AND O&M COST FORECAST BY YEAR
(MILLIONS OF 2023 NOMINAL DOLLARS)[6]

Line No.	Year	2023 (actual capital only)	2024 (actual exp for Nov & Dec)	2025	2026	2027	2028	2029	2030	Total
1	BCS	$41.8	$44.4	$41.1	–	–	–	–	–	$127.3
2	CC&B 25.4	–	9.1	64.8	$53.7	–	–	–	–	127.6
3	C2M	39.8	36.2	1.9	39.1	$102.0	$110.0	$130.3	$42.0	501.5
4	Total	$81.7	$89.7	$107.8	$92.9	$102.0	$110.0	$130.3	$42.0	$756.4

PG&E's Application (as updated in Supplemental Testimony) requests Commission authorization to recover a revenue requirement of $315.1 million to cover the costs forecasted in A.24-10-014. In Supplemental Testimony, PG&E described updates to its requested revenue requirement based on planned operative date changes described in Supplemental Testimony.

B.! Joint CCAs' Positions

In its testimony, Joint CCAs explained that PG&E is the statutorily designated billing

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5 PG&E Errata Rebuttal Testimony (dated Oct. 20, 2025), Chapter 1: Introduction and Overview, Table 1-1.

6 !"., Chapter 1: Introduction and Overview, Table 1-2.

agent for CCAs in its service territory, and that PG&E provides "metering, billing, collection, and customer service" to CCA customers.[7] Under this setup, PG&E bills CCA customers on behalf of CCAs and handles the collection and transfer of payments made by CCA customers to CCAs.[8] Currently, more than half of PG&E's customers are unbundled and receive service from CCAs, and additional CCA expansion is expected in the next few years.[9] Therefore, the BMI upgrades should result in billing systems and processes that are sufficient to meet CCA customer needs, and are designed to equitably serve both PG&E's bundled and unbundled customers.[10] For example, the bills PG&E issues CCA customers should contain accurate and fair representations of their rates and other key customer-facing information, and should not obfuscate or misrepresent rate differences between bundled and unbundled customers.[11] Similarly, PG&E's new system should address billing issues experienced by CCAs and CCA customers and improve PG&E's performance on key billing system efficiency metrics with minimal disruption to customers.[12]

It is further imperative that BMI costs are appropriately and fairly functionalized and allocated to unbundled customers because CCA customers will be responsible for part of the costs of the BMI.[13] Finally, given the billing agent and competitive relationship between PG&E and the CCAs in its service territory, it is important that PG&E's billing system and cost allocation proposals do not confer an unfair competitive advantage upon PG&E.[14]

Joint CCAs recommended a number of specific changes related to bill presentation, data quality and access, reporting, rate implementation projects, CCA service fee updates, and PG&E's proposed functionalization of the BMI revenue requirement. Specifically, Joint CCAs recommended that the Commission:[15]

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[7] Direct Testimony of Kyra J. Coyle on Behalf of the Joint Community Choice Aggregators in PG&E's Billing Modernization Initiative (Errata Jul. 1, 2025), pp. 6:25-26 – 7:1.

[8] !". at 7:1-3.

[9] !". at 7:3-5.

[10] !". at 7:5-8.

[11] !". at 11:11-15.

[12] !". at 48:8-17.

[13] !". at 7:11-14.

[14] !". at 7:15-18.

[15] #$$%&". at 8-10.

- Order PG&E to implement the following changes to facilitate CCAs' communications with their customers via customer bill messaging:
    - Shorten the timeline to process changes to CCA-specific bill messaging to be in line with Southern California Edison Company's (SCE) timeline of two business days.
    - Design the final end-state billing system to have increased flexibility and text space for messaging (in both the "swim lane" and "on-bill message" portions of the bill).
    - Limit the ability of PG&E to modify requested CCA-specific messaging.
    - Design the end-state billing system to allow placement changes of the CCA messaging (*e.g.*, allow the "about" information to be moved from the bottom right corner).
    - Design the end-state billing system to allow CCAs to incorporate customer-specific messaging on customer bills (*i.e.*, messaging specific to particular customer classes, to customers who are enrolled in specific programs like California Alternate Rates for Energy (CARE) or Family Electric Rate Assistance (FERA), or to electric vehicle (EV) customers).
    - Design the end-state billing system to allow clickable URLs in online bills, CCA logos in color, and messaging in color.
- Order PG&E to conduct joint PG&E-CCA stakeholder workshops prior to the design portion of Phase 3 of the BMI, covering: comprehensive bill redesign, dynamic rate bill presentation, and any remaining implementation issues arising out of the CCA bill presentation changes discussed above;
- Reflect all discounts that are calculated based on the total bill (*e.g.*, CARE and FERA) in a completely consistent manner and as a reduction to an eligible customer's total electric charges;
- Separate the Power Charge Indifference Adjustment (PCIA) as a separate line item on customers' bills, so that it can be presented in a consistent manner that reflects the kWh usage and applicable kWh rate used to calculate the PCIA;
- Order PG&E to functionalize all BMI costs it proposes to functionalize to the generation function to the distribution function instead;

- Reject PG&E's proposal to recover the costs associated with the CC&B 25.1 upgrade as BMI costs;
- Order PG&E to ensure its BMI addresses certain shortcomings and persistent billing problems associated with its legacy billing system, including by:
  - Sharing certain critical billing data with CCAs.
  - Addressing various issues with the quality of the billing data currently shared with the CCAs.
  - Dedicating more resources toward resolving CCA customer billing issues and delays in a timely manner, including via a designated PG&E point of contact for such issues and a semi-annual PG&E-CCA stakeholder workshop on resolving outstanding technical billing issues.
  - Clarifying, via an advice letter filing, PG&E's plan regarding how and when it will communicate with various customer groups on major upcoming changes arising out of the BMI, with the constraint that PG&E must provide at least three months' notice in advance of implementation of such billing changes.
  - Remediating various issues with billing mechanics and delays related to rate switch requests, inaccurate applications of bill credits, and backlogged billing projects.
- Order PG&E to regularly track and publicly report on its billing system efficiency metrics, and ensure that its BMI allows it to achieve consistent quarterly improvements on these efficiency metrics;
- With respect to the rollout of the BMI, order PG&E to: (1) commit to specific dates certain for achieving implementation of its backlogged rate projects, and (2) commit to a specific timeline of seven business days for resolving any CCA billing and revenue delays arising out of the BMI deployment; and
- Order PG&E to clearly outline the BMI's likely impact on CCA service fees and commit to service fee updates post BMI implementation.

Joint CCAs' recommended adjustments to PG&E's expense and capital expenditure forecasts are reflected in the table below:

JCCA'S RECOMMENDED ADJUSTMENTS
(MILLIONS OF DOLLARS)[16]

Line No.	JCCA Recommended Budget	BCS	CC&B 25.4	C2M	Total
1	Capital	$117.0	–	$376.5	$493.5
2	Expense	3.0	–	80.0	83.0
3	Subtotal	120.0	–	456.5	576.5
4	Contingency	$8.0	–	49.0	57.0
5	Total	$128.0	–	$505.5	$633.5

IV.! DESCRIPTION OF THE SETTLEMENT TERMS

The Partial Settlement Agreement resolves all issues contested by the Joint CCAs in PG&E's BMI Application. The Settling Parties request that the Partial Settlement Agreement be appended to the Commission's decision in this case. To facilitate the Commission's review, a description of the Partial Settlement Agreement follows.

A.! Introductory Sections of the Partial Settlement Agreement

After a brief preamble, Section 1 of the Partial Settlement Agreement, entitled "The Parties," describes the Settling Parties—PG&E and Joint CCAs. Section 2, entitled "General Recitals," provides a chronological recitation of general factual information relevant to the Partial Settlement Agreement, from PG&E's filing of this Application on October 23, 2024, to the settlement conference on June 19, 2026.

B.! Partial Settlement Agreement Terms and Conditions

Section 3 of the Partial Settlement Agreement contains the terms and conditions of the Partial Settlement Agreement. Section 3.1 provides for a process by which PG&E may seek extensions for certain provisions of the Partial Settlement Agreement in the event that the Commission adopts the Partial Settlement Agreement but does not approve cost recovery sufficient for PG&E to implement C2M or an end-state billing system with substantially similar capabilities (as detailed in Appendix A to the Partial Settlement Agreement).

Section 3.2 provides that, upon the Commission's adoption of the Partial Settlement Agreement, PG&E agrees to reduce overall 2024-2030 total capital expenditure and expense forecasts as set forth in Tables 1 and 2, below. The reductions are not tied to any cost, project, or

[16] PG&E Errata Rebuttal Testimony (dated Oct. 20, 2025), Chapter 1: Introduction and Overview, Table 1-6; '$$%()'* Coyle Direct at 47:14-17.

Major Work Category. The Settling Parties agree that the adjusted forecasts are reasonable but acknowledge and agree that the issue of the reasonableness of PG&E's 2024-2030 total capital expenditure and expense forecasts is still in dispute in A.24-10-014 among other parties that are not signatories to the Partial Settlement Agreement.

PARTIAL SETTLEMENT AGREEMENT TABLE 1
EXPENSE FORECAST (PG&E)
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2024-2030 Total
1	PG&E Requested	$87,181
2	Settlement Offer	$81,595
3	Difference	$(5,586)

PARTIAL SETTLEMENT AGREEMENT TABLE 2
CAPITAL EXPENDITURE FORECAST (PG&E)
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2021-2030 Total
1	PG&E Requested	$669,206
2	Settlement Offer	$586,614
3	Difference	$(82,592)

The Settling Parties also request Commission approval of the specific costs associated with the Partial Settlement Agreement proposals, which are shown separately in Table 3, below.[17]

[17] Note: the capital and expense figures set forth in Table 3 are incorporated within the settlement offer capital and expense forecasts set forth in Tables 1 and 2.

PARTIAL SETTLEMENT AGREEMENT TABLE 3
PG&E CAPITAL AND EXPENSE FORECAST
ASSOCIATED WITH SETTLEMENT AGREEMENT PROPOSALS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	Total
1	Capital	$21,000
2	Expense	$3,000

Section 3.3 describes PG&E's commitments to adopt certain modifications to bill presentation and messaging, based in part on Joint CCAs' recommendations in testimony. These commitments include conducting workshops for a comprehensive bill redesign and implementing specific changes to PG&E's bill design for the benefit of unbundled customers.

Section 3.4 describes PG&E's commitments to improve data quality, billing mechanics, and communication processes to address many of the concerns raised by Joint CCAs in testimony.

Section 3.5 describes additional reporting commitments by PG&E.

Section 3.6 describes PG&E's commitment to resolve CCA billing and revenue delays resulting from BMI deployment.

Section 3.7 provides that, once the BMI is complete, PG&E agrees to propose updates in its next general rate case to its CCA-specific fees.

C.! General Provisions and Reservations

Section IV of the Partial Settlement Agreement consists of general provisions and reservations to which the Settling Parties have agreed.

V.! THE PARTIAL SETTLEMENT AGREEMENT IS REASONABLE IN LIGHT OF THE WHOLE RECORD, CONSISTENT WITH LAW, AND IN THE PUBLIC INTEREST

Under Rule 12.1(d) of the Commission's Rules of Practice and Procedure, in order for a settlement to be approved by the Commission, the settlement must be: (1) reasonable in light of the whole record; (2) consistent with law; and (3) in the public interest. The Commission has stated:

> In evaluating whether a settlement meets these criteria, we consider a variety of factors, including the strength of the applicant's case, the development of the

> record, including the extent to which discovery has been completed, whether the major issues are addressed by the settlement, and the reaction and/or support of interested parties.[18]

Based on the foregoing criteria, the Settling Parties respectfully submit that the Partial Settlement Agreement meets the applicable legal standards, and request that the Commission approve the Partial Settlement Agreement without modification.

A.! The Partial Settlement Agreement is Reasonable in Light of the Whole Record

The Commission has explained that there is "a strong public policy favoring settlement of disputes if they are fair and reasonable in light of the whole record."[19] Several factors support the conclusion that the Partial Settlement Agreement is reasonable in light of the whole record. First, PG&E's BMI Application was accompanied by eight chapters of testimony detailing the need for a billing system upgrade, the target state billing system, the implementation plan for each stage, a cost-benefits analysis, proposed capital and expense forecasts, proposed revenue requirements, and proposed cost recovery for the BMI Application. PG&E submitted over 350 pages of work papers that included details supporting the scope of work, cost forecasts, and cost-benefits analysis. In addition, PG&E responded to nearly 200 data requests (including subparts) from the Joint CCAs in this proceeding.

Second, based on a comprehensive review of PG&E's BMI Application and discovery responses, the Joint CCAs submitted Direct and Rebuttal Testimony providing detailed recommendations to ensure that the final end-state billing system would appropriately and fairly serve the needs of CCAs and their customers. These recommendations were grounded in expert analysis, on-the-ground feedback from CCA billing staff, and CCA customer feedback. Other than PG&E, no party to this proceeding disputed the merits of or the need for the Joint CCAs' recommendations through testimony.

Finally, the Partial Settlement Agreement is based on a significant level of engagement between PG&E and the Joint CCAs. PG&E's BMI Application has been subject to a thorough and comprehensive review by the Joint CCAs and their expert witness. Joint CCAs represent the interests of their customers, which make up a significant portion of PG&E's customers. Through the discovery and months-long settlement process, there has been a thorough dialogue between

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[18] D.04-05-055, p. 20.

[19] D.23-10-025, p. 12.

PG&E and the Joint CCAs regarding likely litigation positions, and responses to those positions, in order to come to a compromise settlement. All of this demonstrates that the Partial Settlement Agreement is reasonable in light of the whole record.

B.! The Partial Settlement Agreement is Consistent with the Law

In evaluating whether a settlement agreement is consistent with the law, "the Commission must be assured that no term of the settlement agreement contravenes statutory provisions or prior Commission decisions."[20] The Partial Settlement Agreement is consistent with the law in that it complies with all applicable statutes and prior Commission decisions, including the Commission's decision in PG&E's 2023 GRC (D.23-11-069), which authorized PG&E to file a separate application seeking recovery for a billing system upgrade.[21]

The Partial Settlement Agreement is further consistent with PG&E's obligations set forth in the Commission's CCA Code of Conduct. The Commission's Code of Conduct governing the conduct of investor-owned utilities in their interactions with and treatment of CCAs applies to issues of bill presentation.[22] The Code of Conduct was adopted to ensure CCAs are able to "compete on a fair and equal basis with other [load serving entities], and to prevent utilities from using their position or market power to gain unfair advantages."[23] The Code of Conduct provides, among other things, that PG&E may not, "through a tariff provision or otherwise, discriminate between its own customers and those of a CCA."[24] The Partial Settlement Agreement provides for meaningful updates to improve transparency and messaging on unbundled customer bills, to improve the data exchange processes between PG&E and CCAs to facilitate unbundled customer billing, and sets forth numerous other provisions generally designed to improve communications and processes between PG&E, CCAs, and their customers. Each of these updates are designed to ensure that unbundled customers are equitably served by PG&E's billing system upgrades.

C.! The Partial Settlement Agreement is in the Public Interest

The Partial Settlement Agreement also is in the public interest. It provides for a reasonable disposition and compromise of issues that otherwise would have been litigated in this

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[20] D.10-12-036, p. 26.

[21] D.23-11-069, pp. 546-550.

[22] #$$ Coyle Direct at 11:22-24.

[23] D.12-12-036, Finding of Fact (FOF) 4 (definition added).

[24] !". at Attachment 1: Code of Conduct and Expedited Complaint Procedure, Rules 14 and 18.

proceeding. The Partial Settlement Agreement represents significant compromises of adverse litigation positions that would have been taken by the Settling Parties in the proceeding, and thus will avoid needless and contentious litigation and resource drain on the part of the parties and the Commission. Furthermore, the Partial Settlement Agreement provides for an approximately $2.6 million reduction in expenses, and approximately $61.6 million reduction in capital expenditures, from what PG&E proposed in the Application (net of the costs of settlement proposals). Neither PG&E nor the Joint CCAs precisely obtained the outcome they desired, and each of them gave up and compromised on significant, strongly held positions.

VI.! THE SETTLING PARTIES HAVE COMPLIED WITH THE REQUIREMENTS OF RULE 12.1(B)

Commission Rule 12.1(b) requires parties to provide a notice of a settlement conference at least seven days before a settlement is signed. On June 10, 2026, PG&E notified all parties on the service list of a settlement conference scheduled for June 19, 2026. The settlement conference was held as scheduled to describe and discuss the terms of the proposed settlement. Representatives of PG&E, the Joint CCAs, and Cal Advocates participated in the settlement conference. After the settlement conference was concluded, the Partial Settlement Agreement was finalized and executed.

VII.! THE PARTIAL SETTLEMENT AGREEMENT SHOULD BE ADOPTED WITHOUT MODIFICATION

The Settling Parties view the Partial Settlement Agreement as a cohesive bargain, which reflects compromises on issues addressed in testimony. Thus, the Partial Settlement Agreement is indivisible, and each part is interdependent on each and all other parts. Accordingly, the Partial Settlement Agreement provides that, "Any party may withdraw from this Settlement Agreement if the Commission, or any court of competent jurisdiction, modifies, deletes from, or adds to the disposition of the matters settled herein." Adoption of a portion of the Partial Settlement Agreement would necessarily upset the balance of interests that led to the settlement's execution, and it would free parties from their settlement obligations. In evaluating the Partial Settlement Agreement, the Settling Parties agreed that the Commission should consider the entire Settlement Agreement, and not just its individual parts, consistent with Commission precedent:

> In assessing settlements, we consider individual settlement provisions but, in light of strong public policy favoring settlements, we do not base our conclusion on

> whether any single provision is the optimal result. Rather, we determine whether the settlement as a whole produces a just and reasonable outcome.[25]

The settlement among PG&E and Joint CCAs reaches a just and reasonable result, and the Commission should approve the Partial Settlement Agreement.

VIII.! CONCLUSION

For the foregoing reasons, the Settling Parties respectfully request that the Commission approve the BMI Application Partial Settlement Agreement attached as Attachment A without modification, in accordance with the legal standards set forth in Rule 12 of the Commission's Rules of Practice and Procedure.

Respectfully Submitted,

By: *=:=!" ' 2) *!><!? 1@%*
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Dated: July 9, 2026

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[25] D.11-05-018, p. 16.

ATTACHMENT A

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of Its Billing Modernization Initiative (U 39 M)	Application No. 24-10-014

PACIFIC GAS AND ELECTRIC COMPANY BILLING MODERNIZATION INITIATIVE SETTLEMENT AGREEMENT AMONG PACIFIC GAS AND ELECTRIC COMPANY AND THE JOINT COMMUNITY CHOICE AGGREGATORS

PACIFIC GAS AND ELECTRIC COMPANY BILLING MODERNIZATION INITIATIVE SETTLEMENT AGREEMENT AMONG PACIFIC GAS AND ELECTRIC COMPANY AND THE JOINT COMMUNITY CHOICE AGGREGATORS

Pacific Gas and Electric Company (PG&E) and Peninsula Clean Energy Authority, Ava Community Energy, Central Coast Community Energy, Marin Clean Energy, City of San José, Silicon Valley Clean Energy, and Sonoma Clean Power Authority (collectively, the Joint CCAs, and together with PG&E, the Settling Parties) agree to settle the *Application of Pacific Gas and Electric Company for Approval of Its Billing Modernization Initiative*, A.24-10-014, on the following terms and conditions.

This settlement agreement (Partial Settlement Agreement) is entered into as a compromise in order to minimize the time, expense, and uncertainty of further regulatory proceedings in PG&E's Billing Modernization Initiative (BMI) Application (Application). The Settling Parties agree to the following terms and conditions as a complete and final resolution of the issues contested by the Joint CCAs in the Application. This Partial Settlement Agreement constitutes the sole agreement between the Settling Parties concerning the subject matter of this Partial Settlement Agreement.

As explained herein, the Settling Parties shall file a joint motion, pursuant to Rule 12.1(a) of the California Public Utilities Commission's Rules of Practice and Procedure (Settlement Motion), requesting California Public Utilities Commission (Commission or CPUC) approval of this Partial Settlement Agreement.

I.
THE PARTIES

1.1 The parties to this Partial Settlement Agreement are PG&E and the Joint CCAs.

1.2 PG&E is an investor-owned public utility in California and is subject to the jurisdiction of the Commission with respect to providing gas and electric service to customers in California.

1.3 Joint CCAs are community choice aggregators (CCAs) in PG&E's service territory. The Joint CCAs' customers receive a consolidated bill from PG&E. This bill includes the customers' energy generation charge from their CCA and transmission and distribution charges from PG&E.

II.
GENERAL RECITALS

2.1 PG&E filed its BMI Application (A.24-10-014) and Initial Testimony on October 23, 2024. PG&E's Application requested approximately $761.3 million in funding for 2023-2030 to upgrade and replace PG&E's aging billing systems.

2.2 On November 25, 2024, Peninsula Clean Energy Authority filed a protest.

2.3 On December 5, 2024, PG&E filed a reply to protests and responses.

2.4 The Commission issued its Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo) on March 27, 2025. The Scoping Memo categorized the proceeding as a ratesetting proceeding, set forth the issues to be determined in the proceeding, determined that evidentiary hearings were needed, adopted a schedule for the proceeding, and addressed other administrative issues.

2.5 On June 25, 2025, Ava Community Energy, Central Coast Community Energy, the City and County of San Francisco, acting by and through its Public Utilities Commission, Marin Clean Energy, City of San José, Silicon Valley Clean Energy, and Sonoma Clean Power Authority filed a motion for party status. The Administrative Law Judge (ALJ) granted that motion by email ruling on June 30, 2025.

2.6 Joint CCAs and other parties to the proceeding submitted Direct Testimony on June 30, 2025. Joint CCAs recommended a complete disallowance of the Customer Care and Billing (CC&B) stage of the BMI.[1] Joint CCAs further recommended a number of specific changes related to bill presentation, data quality and access, reporting, rate implementation projects, CCA service fee updates, and PG&E's proposed functionalization of the BMI revenue requirement.

2.7 PG&E and Joint CCAs submitted Rebuttal Testimony on July 30, 2025.[2] In its Rebuttal Testimony, PG&E updated its cost forecast to approximately $756.4 million.

2.8 The parties to the proceeding met on August 14, 2025, September 5, 2025, and January 14, 2026 to discuss a potential settlement of the proceeding, but did not reach a settlement agreement. PG&E and the Joint CCAs regularly met separately in ongoing settlement negotiations.

2.9 The parties filed Joint Case Management Statements on August 20, 2025, January 30, 2026, and May 7, 2026, which each indicated that no settlement had been reached as of the filing date.

2.10 On March 17, 2026, PG&E filed Supplemental Testimony describing material changes to the projected timeline for the BMI, as directed by the ALJ.

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[1] Note that the City and County of San Francisco, acting by and through its Public Utilities Commission (CleanPowerSF), joined in the Joint CCAs' June 30, 2025, Direct Testimony submission. However, CleanPowerSF is not included in the group of Joint CCAs as defined in this Partial Settlement Agreement.

[2] Note that the City and County of San Francisco, acting by and through its Public Utilities Commission (CleanPowerSF), joined in the Joint CCAs' July 30, 2025, Rebuttal Testimony submission. However, CleanPowerSF is not included in the group of Joint CCAs as defined in this Partial Settlement Agreement.

2.11 On June 5, 2026, the Settling Parties reached an agreement in principle.

2.12 The Commission held an evidentiary hearing on June 8 and June 9, 2026.

2.13 On June 10, 2026, PG&E gave notice to all parties of a settlement conference to be held on June 19, 2026, pursuant to CPUC Rule 12.1(b). PG&E, Joint CCAs, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), and Direct Access Customer Coalition (DACC) participated in the June 19, 2026 Settlement Conference. On June 19, 2026, following the settlement conference, PG&E provided an email summary of the agreement in principle to the parties not in attendance, which included Small Business Utility Advocates, The Utility Reform Network, and Leapfrog Power, Inc.

III.
SETTLEMENT AGREEMENT TERMS AND CONDITIONS

3.1 Introduction

PG&E agrees to implement the items listed in Subsections 3.3(a)(iv), 3.3(d), 3.4(a), 3.4(b), 3.4(d), 3.4(f), and 3.4(g) below in consultation with the Joint CCAs, provided that the Commission approves the Partial Settlement Agreement and sufficient cost recovery in A.24-10-014 for PG&E to implement the Customer-to-Meter (C2M) upgrade (Stage 3 of the BMI), or an end-state billing system with Substantially Similar Capabilities (as defined in Appendix A hereto). In the event that the Commission does not approve cost recovery sufficient to implement C2M or an end-state billing system with Substantially Similar Capabilities, PG&E will meet and confer with the Joint CCAs to determine whether PG&E will need to submit a Rule 16.6 request for an extension to deliver the impacted Partial Settlement Agreement provisions, as determined in consultation with the Joint CCAs and in accordance with the guidelines provided in Appendix A. Any such request would seek an extension to allow PG&E sufficient time to secure the incremental cost recovery needed to implement the billing system capability necessary for PG&E to deliver the relevant Partial Settlement Agreement provision. The Joint CCAs commit to supporting the reasonableness of such incremental cost recovery.

For the avoidance of doubt, the Settling Parties only intend to allow for this flexibility in implementation date(s) for the specific Partial Settlement Agreement provision(s), if any, that PG&E does not have the technical capability to implement in the event that the Commission does not approve cost recovery sufficient for PG&E to implement C2M or an end-state billing system with Substantially Similar Capabilities.

Delivery of the Partial Settlement Agreement provisions not specifically listed above is not contingent upon the implementation of incremental capabilities in the final end-state billing system. Therefore, in the event that the Commission adopts the Partial Settlement Agreement, PG&E agrees to implement all the Partial Settlement Agreement provisions not specifically listed above.

3.2 Total Expense and Capital Expenditure Forecasts

Upon the Commission's adoption of the Partial Settlement Agreement, PG&E agrees to reduce overall 2024-2030 total capital expenditure and expense forecasts as set forth in Tables 1 and 2, below. The reductions would not be tied to any cost, project, or Major Work Category.

The capital and expense figures in Tables 1 and 2 are the net result of (1) cost reductions in recognition of the proposed Customer Care & Billing (CC&B) 25.4 upgrade (Stage 2 of the BMI) costs that would not have otherwise been incurred absent the stabilizing upgrade, and (2) the additional costs associated with implementing the Partial Settlement Agreement provisions in Sections 3.3 through 3.7 below (the Settlement Agreement Proposals), which are shown in Table 3 below. As part of this Partial Settlement Agreement, the Settling Parties request Commission approval of the specific costs associated with the Settlement Agreement Proposals, which are shown separately in Table 3.

The Settling Parties acknowledge and agree that the issue of the reasonableness of PG&E's 2024-2030 total capital expenditure and expense forecasts associated with the BMI will not be fully resolved by this Partial Settlement Agreement. This issue is still in dispute in A.24-10-014 among other parties to A.24-10-014 that are not signatories to this Partial Settlement Agreement. With this Partial Settlement Agreement, and in light of the compromises reflected therein, the Settling Parties agree that the 2024-2030 total capital expenditure and expense forecasts for the BMI set forth in Table 1 and Table 2 below are reasonable. The Joint CCAs further commit to supporting the reasonableness of PG&E's 2024-2030 total capital expenditure and expense forecasts set forth in the Partial Settlement Agreement, as reflected in Table 1 and Table 2 below, throughout the pendency of A.24-10-014. Nothing herein limits or affects the ability of other parties to A.24-10-014 (aside from the Joint CCAs) to litigate the reasonableness of PG&E's 2024-2030 total capital expenditure and expense forecasts associated with the BMI in A.24-10-014.

TABLE 1
EXPENSE FORECAST (PG&E)
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2024-2030 Total
1	PG&E Requested	\$87,181
2	Settlement Offer	\$81,595
3	Difference	\$(5,586)

TABLE 2
CAPITAL EXPENDITURE FORECAST (PG&E)
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2021-2030 Total
1	PG&E Requested	$669,206
2	Settlement Offer	$586,614
3	Difference	$(82,592)

TABLE 3
PG&E CAPITAL AND EXPENSE FORECAST
ASSOCIATED WITH SETTLEMENT AGREEMENT PROPOSALS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	Total
1	Capital	$21,000
2	Expense	$3,000

3.3 Modifications to Bill Presentation and Messaging

a. PG&E agrees to conduct workshops with the CCAs in its service territory prior to Stage 3 of the BMI. PG&E agrees that the purpose of the workshops is to:
   i. Undertake a comprehensive bill redesign with the goal of redesigning bills to be clear and easily understandable to both unbundled and bundled customers (including by evaluating proposed changes through customer research and feedback).
   ii. Work collaboratively with the CCAs to determine dynamic rate bill presentation.
   iii. Determine the implementation details for the list of specific bill presentation changes and associated process changes in Subsection (iv), below.
   iv. File an advice letter (consistent with the requirements of Commission Decision 07-07-047), within 12 months of implementation of the final BMI end-state billing system requesting Commission approval (to the extent necessary) of the following changes to PG&E's bill design and associated processes:
      1. PG&E will reliably and consistently process CCA requested changes to the text of CCA-specific bill messaging: (a) with the next scheduled IT release, provided the CCA makes the request and provides final text changes to PG&E at least five business days prior to the scheduled IT release, and (b) under no circumstances to exceed thirty days from the

date of the CCA request, except in the instance of unforeseen issues or events not within PG&E's control;

2. PG&E will reliably and consistently process CCA requested changes to URLs within the CCA Company Information section or CCA-specific bill messaging with the next scheduled IT release, provided that: (a) the CCA submits final URL information to PG&E at least fifteen business days prior to the scheduled IT release, and (b) PG&E may schedule such changes for a subsequent release if necessary to complete ADA-compliant tagging within the code or required accessibility testing;
3. Increased flexibility and text space for CCA messaging in both the "swim lane" and "on-bill message" portions of unbundled customer bills;
4. A new limitation on PG&E's ability to modify CCA-specific messaging on unbundled customer bills such that PG&E can only make modifications in instances in which revisions to messaging are necessary to ensure compliance with applicable regulatory and legal requirements and a standard process by which PG&E provides the final version of any modified language to CCAs for final signoff;
5. Increased flexibility to accommodate placement changes for CCA messaging on unbundled customer bills;
6. Incorporation of customer-specific messaging on unbundled customer bills; and
7. Incorporation of clickable URLs, CCA logos in color, and messaging in color.

v. File an advice letter or, if needed, an application, within 12 months of implementation of the final BMI end-state billing system requesting Commission approval of: (1) additional comprehensive bill redesign changes (aside from those listed above in Subsection (iv)) arising from stakeholder discussions in the workshops, including, but not limited to, changes related to dynamic rate presentation, and (2) recovery of any additional costs needed to implement bill redesign changes arising from stakeholder discussions in the workshops (including those listed above in Subsection (iv)).

b. PG&E agrees to ensure that nothing in the design of the final BMI end-state billing system will prevent PG&E from being able to implement the bill presentation changes and associated processes listed above in Subsection 3.3(a)(iv) following implementation of the final BMI end-state billing system.

c. PG&E agrees to add a static SA-level bill message on the "Details of PG&E Electric Delivery Charges" portion of eligible unbundled customers' bills within 6 months of the end of the Stabilization phase of the CC&B 25.4 upgrade explaining that the CARE/FERA discount is the same for all customers, regardless of whether their electricity is supplied by PG&E or a CCA. The precise language of the message will be as follows, subject to any necessary modifications identified via PG&E's standard customer testing process, to be conducted in consultation with the Joint

CCAs: "[CARE or FERA (as applicable)] discounts are applied equally to all eligible customers regardless of whether their electricity is supplied by PG&E, a CCA, or another electric service provider." The below image captures the agreed-upon placement (and starred and bolded format) for this message on unbundled customers' bills:

Details of PG&E Electric Delivery Charges

03/14/2025 - 04/13/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: E1 TB Residential Service
Enrolled Programs: CARE (Renew by 04/04/2025)

03/14/2025 – 04/13/2025	**Your Tier Usage** 1 | 2		
Tier 1 Allowance	232.50 kWh	(31 days x 7.5 kWh/day)	
Tier 1 Usage	232.500000 kWh	@ $0.40730	$94.70
Tier 2 Usage	196.440000 kWh	@ $0.51031	100.25
CARE Discount**			-74.79
Generation Credit			-66.78
Power Charge Indifference Adjustment			4.76
Franchise Fee Surcharge			0.45
Daly City Utility Users' Tax (5.000%)			2.91
Total PG&E Electric Delivery Charges			**$61.50**

Service Information

Meter #	REDACTED - Customer Info
Total Usage	428.940000 kWh
Baseline Territory	T
Heat Source	B - Not Electric
Serial	T
Rotating Outage Block	9P

Your CARE usage is charged at these rates ($/kWh). Differences may occur due to rounding.

03/14/2025 - 04/13/2025	
Tier 1	0.24947
Tier 2	0.31643
Tier 2 Usage continued	0.31643

**** CARE line item explanation here; Additional Messages to move down**

Additional Messages

You received a **California Climate Credit** on your electric bill. Learn how you can use these savings to further reduce your energy costs and help fight climate change at **cpuc.ca.gov/climatecredit.**

d. PG&E agrees to display the PCIA as a separate line item on all customers' bills, including the total kilowatt-hour usage and applicable kilowatt-hour rate used to calculate the PCIA charge as part of, and no later than, the completion of implementation of the final BMI end-state billing system. PG&E agrees this information will appear in the "Details of Electric Charges" bill section of bundled customer bills and the corresponding "Details of PG&E Electric Delivery Charges" bill section of unbundled customer bills.

3.4 Improvements to Data Quality, Billing Mechanics & Communication Processes

a. PG&E agrees to provide CCAs with all data files described in the portions of Table 6 of the Direct Testimony of Kyra Coyle reproduced in Appendix B as a regular course of business upon completion of implementation of the final BMI end-state billing system, except for hourly and sub-hourly billing interval data (addressed separately in Subsection 3.4(b) below).

b. PG&E agrees to provide CCAs with the hourly and sub-hourly billing quality billing interval data described in Table 6 of the Direct Testimony of Kyra Coyle (reproduced in Appendix B), delivered within 24 hours of the meter bill segment creation date/time,[3] as a regular course of business, pursuant to the following phased schedule:

[3] "Bill segment creation" is the system event where the PG&E bill segment is billed and moved into frozen status. Within a typical Bill Window, PG&E expects to receive usage, create a PG&E Bill Segment for transmission and distribution charges, send usage to CCAs, and wait for the return of CCA charges. The opening of the Bill Cycle does not mean the meter has been read.

   i. For SmartMeter Enabled, interval-billed, commercial CC&B-billed customers: provided as a regular course of business by February 1, 2027.
   ii. For SmartMeter Enabled, interval-billed, residential CC&B-billed customers: provided as a regular course of business within 60 days of the go-live date for the CC&B 25.4 upgrade and no later than December 31, 2027.
   iii. For any remaining customers not included in Subsection (i)-(ii) above, except for those customers with manual read meters (*i.e.*, SmartMeter opt-out and Electric Meter Read customers), and SmartMeter Anchor Billed customers: provided as a regular course of business upon completion of implementation of the final BMI end-state billing system.
   iv. Prior to the delivery dates described in Subsections 3.4(b)(i)-(iii) above, PG&E will conduct system testing and tuning and work with the Joint CCAs to ramp up the data transfer process.
   v. If PG&E determines it is able to offer delivery dates for certain portions of this data on an accelerated timeline as compared to that contained in this term, it will meet and confer with the Joint CCAs to determine whether the parties can reach agreement on an updated, earlier delivery date for such data. For the avoidance of doubt, this meet and confer process is not applicable to PG&E requests for delayed delivery dates.

c. PG&E agrees its current data sharing systems and processes will remain available and functional until the final end-state BMI is fully implemented, such that there will be no gaps in PG&E's data sharing capabilities with CCAs. Nothing in this Partial Settlement Agreement is intended to impact PG&E's current practice of providing CCAs with billing quality billing interval data for MV 90 and solar billing plan meters as a regular course of business.

d. PG&E agrees to design its BMI end-state billing system to address the data quality issues described in the portions of Table 7 of the Direct Testimony of Kyra Coyle reproduced in Appendix B in accordance with the specific recommendations in Table 7. PG&E commits to improving and streamlining its CCA notification process associated with a CCA customer's transition from a Rate Ready account to a Bill Ready account.

e. PG&E agrees to take the following actions to improve PG&E-CCA communication by June 30, 2026:
   i. Provide a designated point of contact for resolving technical billing issues impacting CCAs; and
   ii. Hold semi-annual PG&E-CCA workshops on resolving technical billing issues.

f. PG&E agrees to implement a structured change management approach for the C2M stage of the BMI, including a dedicated change-management function with assigned resources and communication plans. As part of this approach, PG&E will provide CCAs with three months' advance notice of material changes that may affect third-party/CCA operations or CCA customers (unless such impacts are discovered within three months of the launch of C2M, in which case PG&E will notify CCAs as soon as possible), along with ongoing updates as the C2M stage progresses. PG&E will also work with CCAs during the testing phase to ensure that C2M functionality does not adversely impact CCA operations.

g. PG&E agrees to design its final BMI end-state system to switch customers between rate schedules no later than one month following the request.
h. PG&E agrees to provide biannual status updates to the CCAs on its ongoing meetings with Commission and/or Energy Division staff on the prioritization of these projects:
    i. EV Submetering;
    ii. Modified Cost Allocation Methodology for Resource Adequacy for other Load Serving Entities (CCAs, ESPs);
    iii. Load Management Standard Compliant RTP Rates for all customer classes;
    iv. NEM and NBT Bill Re-design; and
    v. PCIA line item on bundled customer bills.

3.5 Reporting

a. PG&E agrees to submit a report to the CCAs within 30 days of the execution of this Partial Settlement Agreement identifying data associated with the billing system efficiency metric for delayed electric bills, by bundled versus unbundled customer status, as of the end of 2023, 2024, and 2025.
b. Following submission of the report described in Subsection (a), PG&E agrees to submit annual reports to the CCAs identifying data associated with the following billing system efficiency metrics on a going-forward basis:
    i. Unbillable Revenues (in the aggregate);
    ii. Quality Assurance Standard #8 – Late Commencing Bills (in the aggregate);
    iii. Delayed Bills (by bundled versus unbundled customer status); and
    iv. Customer-Initiated Requests Open > 45 Days (for customers billed using CC&B, in the aggregate).
c. Joint CCAs agree that, in the event that they intend to include or reference the data provided pursuant to the reports described in Subsections (a) and (b) in a public filing with the Commission in order to obtain relief from the Commission related to data reported pursuant to Subsections (a) and (b), they will first meet and confer with PG&E. The purpose of such meet and confer with PG&E would be to notify PG&E of CCA concerns or issues, and understand whether the parties can resolve the concerns or issues bilaterally, without Commission intervention.

3.6 CCA Billing and Revenue Delay Resolution

a. PG&E agrees to resolve any CCA billing and revenue delays resulting from BMI deployment. PG&E cannot commit to a fixed resolution timeframe, as issue complexity and root cause may vary. However, PG&E agrees to prioritize payment continuity for third-party providers by staffing a dedicated cutover support team, conducting end-to-end testing during pre-implementation phases, and implementing heightened monitoring during cutover and stabilization. Ensuring accurate and timely provider payments will be a core operational priority throughout the transition. In the event of the identification of missed or discrepant remittances to CCAs resulting from BMI deployment, PG&E agrees to initiate daily meetings between the affected CCA(s) and a dedicated support contact.

3.7 CCA Service Fees

a. Once the BMI project is complete, PG&E agrees to propose updates in its next general rate case to its CCA-specific fees (*i.e.*, Meter Data Management Fee, Rate-Ready Consolidated Billing Fee, and Bill-Ready Consolidated Billing Fee, and Provider of Last Resort fees) based on its costs incurred to provide the associated services under the final BMI end-state billing system.

IV.
GENERAL PROVISIONS AND RESERVATIONS

The Settling Parties further acknowledge and agree as follows:

4.1 Incorporation of Record

The Settling Parties hereby reference and incorporate their exhibits in the record of this proceeding, including testimony, workpapers, and other exhibits.

4.2 Complete Package

This Partial Settlement Agreement is to be treated as a complete package, not as a collection of separate agreements on discrete issues or proceedings.

4.3 Compromise of Disputed Claims

This Partial Settlement Agreement represents a compromise of disputed claims between the Settling Parties. The Settling Parties have reached this Partial Settlement Agreement after considering the possibility that each Party may or may not prevail on any given issue. The Settling Parties assert that this Partial Settlement Agreement is reasonable in light of the whole record, consistent with the law, and in the public interest. The Settling Parties agree that, in the event the Commission approves this Partial Settlement Agreement, there will be no remaining material, contested facts between them in this proceeding. The Settling Parties further agree that this Partial Settlement Agreement does not necessitate additional hearings.

4.4 Modifications by Commission

In the event the Commission rejects or modifies this Partial Settlement Agreement, the Settling Parties reserve their rights under Rule 12.4 of the Commission's Rules of Practice and Procedure to terminate or renegotiate this Partial Settlement Agreement.

4.5 Commission's Jurisdiction

The Commission has primary jurisdiction over any interpretation, enforcement, or remedies regarding this Partial Settlement Agreement.

4.6 Governing Law

This Partial Settlement Agreement shall be interpreted, governed, and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

4.7 Further Actions

This Partial Settlement Agreement is subject to approval by the Commission and as soon as practicable after all Settling Parties have signed the Partial Settlement Agreement, the Settling Parties, through their respective attorneys, will prepare and file the Settlement Motion. The Settling Parties will furnish such additional information, documents, or testimonies as the Commission may require for purposes of granting the Settlement Motion and approving and adopting the Partial Settlement Agreement, and shall support and mutually defend the Partial Settlement Agreement in its entirety until the Commission has issued final approval of the Partial Settlement Agreement. No Settling Party will contest this Partial Settlement Agreement or the recommendations contained in this Partial Settlement Agreement in any proceeding, or in any other forum, or in any manner before this Commission. It is understood by the Settling Parties that time is of the essence in obtaining the Commission's approval of this Partial Settlement Agreement and that all Settling Parties will extend their best efforts to ensure its adoption by the Commission.

4.8 Voluntary and Knowing Acceptance

Each Settling Party acknowledges and stipulates that it is agreeing to this Partial Settlement Agreement freely, voluntarily, and without any fraud, duress, or undue influence by any other Settling Party. Each Settling Party has read and fully understands its rights, privileges, and duties under this Partial Settlement Agreement, including its right to discuss this Partial Settlement Agreement with its legal counsel, which has been exercised to the extent deemed necessary.

4.9 No Modification

This Partial Settlement Agreement constitutes the entire understanding and agreement of the Settling Parties regarding the matters set forth herein, which may not be altered, amended, or modified in any respect except in writing and with the express written and signed consent of all the Settling Parties hereto. All prior oral or written agreements, settlements, principles, negotiations, statements, representations, or understandings whether oral or in writing and regarding any matter set forth in this Partial Settlement Agreement, are expressly waived and have no further force or effect.

4.10 No Reliance

None of the Settling Parties have relied or presently rely on any statement, promise, or representation by any other Settling Party, whether oral or written, except as specifically set forth in this Partial Settlement Agreement. Each Settling Party expressly assumes the risk of any mistake of law or fact made by such Settling Party or its authorized representative.

4.11 Counterparts

This Partial Settlement Agreement may be executed in counterparts by the different Settling Parties hereto and all counterparts so executed will be binding and have the same effect as if all the Settling Parties had signed one and the same document. All such counterparts will be deemed to be an original and together constitute one and the same Agreement.

4.12 Binding upon Full Execution

This Partial Settlement Agreement will become effective and binding on each of the Settling Parties as of the date it is signed by all Settlement Parties.

4.13 Non-Precedential Effect

This Partial Settlement Agreement is not intended by the Settling Parties to be precedent for any other proceeding, whether pending or instituted in the future. The Settling Parties have assented to the terms of this Partial Settlement Agreement only to arrive at the Settlement embodied in this Partial Settlement Agreement. Each Settling Party expressly reserves its right to advocate, in current and future proceedings, positions, principles, assumptions, arguments and methodologies that may be different than those underlying this Partial Settlement Agreement. The Settling Parties expressly declare that, as provided in Rule 12.5 of the Commission's Rules of Practice and Procedure, this Partial Settlement Agreement is intended to be binding on all parties to the proceeding but should not be considered as a precedent for or against them.

4.14 Enforceability

After issuance of a Commission decision approving and adopting this Partial Settlement Agreement, the Commission may reassert jurisdiction and reopen this proceeding to enforce the terms and conditions of this Partial Settlement Agreement.

4.15 No Admission

Unless expressly stated herein, nothing in this Partial Settlement Agreement or related negotiations may be construed as an admission of any law or fact by any of the Settling Parties, or as precedential or binding on any Settling Party in any other proceeding whether before the Commission, in any court, or in any other state or federal administrative agency. Further, unless expressly stated herein this Partial Settlement Agreement does not constitute an acknowledgement, admission, or acceptance by any Settling Party regarding any issue of law or fact in this matter, or the validity or invalidity of any particular method, theory, or principle of ratemaking or regulation in this or any other proceeding.

4.16 Authority to Sign

Each Settling Party executing this Partial Settlement Agreement represents and warrants to the other Settling Parties that the individual signing this Partial Settlement Agreement and the related Settlement Motion has the legal authority to do so on behalf of the Settling Party.

4.17 Limited Admissibility

Each Settling Party signing this Partial Settlement Agreement agrees and acknowledges that this Partial Settlement Agreement will be admissible in any subsequent Commission proceeding but only for the limited purpose of reflecting or enforcing the Terms and Conditions of this Partial Settlement Agreement.

4.18 Estoppel or Waiver

Unless expressly stated herein, the Settling Parties' execution of this Partial Settlement Agreement is not intended to provide any of the Settling Parties in any manner a basis of estoppel or waiver in this or any other proceeding.

4.19 Indivisibility

This Partial Settlement Agreement embodies compromises of the Settling Parties' positions in this proceeding. No individual term of this Partial Settlement Agreement is assented to by any Settling Party, except in consideration of the other Settling Parties' assents to all other terms. Thus, the Partial Settlement Agreement is indivisible and each part is interdependent on each and all other parts. Any party may withdraw from this Partial Settlement Agreement if the Commission, or any court of competent jurisdiction, modifies, deletes from, or adds to the disposition of the matters settled herein. The Settling Parties agree, however, to negotiate in good faith regarding any Commission-ordered changes to restore the balance of benefits and burdens, and to exercise the right to withdraw only if such negotiations are unsuccessful.

4.20 Effect of Subject Headings

Subject headings in this Partial Settlement Agreement are inserted for convenience only and shall not be construed as interpretations of the text.

V.
EXECUTION

IN WITNESS WHEREOF, the Settling Parties have duly executed this Partial Settlement Agreement. This Partial Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the party represented.

PACIFIC GAS & ELECTRIC COMPANY

By: Vincent Davis
Name: Vincent Davis
Title: Senior Vice President and Chief Customer Officer
Date: 6/24/26

AVA COMMUNITY ENERGY

Signed by:
By: John Newton
DF6A7104FEB248E...
Name: John Newton
Title: Director of Regulatory Affairs
Date: 7/6/2026

CENTRAL COAST COMMUNITY ENERGY

DocuSigned by:
By:
398728BE39B342A...
Name: Robert Shaw
Title: CEO
Date: 7/6/2026

MARIN CLEAN ENERGY

Signed by:
By: Vicken Kasarjian
A3F8D9C35248400...
Name: Vicken Kasarjian
Title: Acting CEO, and COO
Date: 6/30/2026

PENINSULA CLEAN ENERGY AUTHORITY

Signed by:
By: Shawn Marshall
9C58E3AF6586490...
Name: Shawn Marshall
Title: CEO
Date: 6/30/2026

CITY OF SAN JOSÉ

By:
Name: Kevin Fisher
Title: Assistant City Attorney
Date: 7-7-2026

SILICON VALLEY CLEAN ENERGY

Signed by:
By: Maren Wenzel
0C2432D9E7074CA...
Name: Maren Wenzel
Title: Director of Regulatory Policy and Planning
Date: 6/30/2026

SONOMA CLEAN POWER AUTHORITY

Signed by:
By: Neal Reardon
D42ED370FB4748A...
Name: Neal Reardon
Title: Director of Policy
Date: 6/30/2026

APPENDIX A

"Substantially Similar Capabilities" is defined as a billing system with the following eight Capabilities:

Capability 1. Data extraction capability to support fixed bill display elements (logos, color, URLs, placement) consistent with regulatory and accessibility requirements.[4]

Capability 2. Data extraction capability to enable CCA-initiated messaging updates on relevant settlement timelines or other mutually agreed upon timelines.[5]

Capability 3. Capability to display PCIA as a line item per Partial Settlement Agreement specifications.[6]

Capability 4. Capability to exchange billing-quality interval and scalar usage at large scale with CCAs on defined timelines as a regular course of business without gaps in availability or functionality.[7]

Capability 5. Capability to support interval bill-quality data independent of rate classification for interval-capable meters; rate should not block EDI access to available interval data.[8]

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[4] PG&E's ability to deliver the Settlement Agreement provisions in Settlement Agreement Sections 3.3.a.iv.3, 3.3.a.iv.5, 3.3.a.iv.6, and 3.3.a.iv.7 is contingent on an end-state billing system with Capability 1. If the Commission does not approve sufficient cost recovery for PG&E to implement an end-state billing system with Capability 1, PG&E will meet and confer with the Joint CCAs and may, if necessary, seek a Rule 16.6 extension request associated with those Settlement Agreement provisions.

[5] PG&E's ability to deliver the Settlement Agreement provisions in Settlement Agreement Sections 3.3.a.iv.1, 3.3.a.iv.2, and 3.3.a.iv.4 is contingent on an end-state billing system with Capability 2. If the Commission does not approve sufficient cost recovery for PG&E to implement an end-state billing system with Capability 2, PG&E will meet and confer with the Joint CCAs and may, if necessary, seek a Rule 16.6 extension request associated with those Settlement Agreement provisions.

[6] PG&E's ability to deliver the Settlement Agreement provisions in Settlement Agreement Section 3.3.d is contingent on an end-state billing system with Capability 3. If the Commission does not approve sufficient cost recovery for PG&E to implement an end-state billing system with Capability 3, PG&E will meet and confer with the Joint CCAs and may, if necessary, seek a Rule 16.6 extension request associated with those Settlement Agreement provisions.

[7] PG&E's ability to deliver the Settlement Agreement provisions in Settlement Agreement Sections 3.4.b.i and 3.4.b.ii is contingent on an end-state billing system with Capability 4. If the Commission does not approve sufficient cost recovery for PG&E to implement an end-state billing system with Capability 4, PG&E will meet and confer with the Joint CCAs and may, if necessary, seek a Rule 16.6 extension request associated with those Settlement Agreement provisions.

[8] PG&E's ability to deliver the Settlement Agreement provisions in Settlement Agreement Section 3.4.b.iii is contingent on an end-state billing system with Capability 5. If the Commission does not approve sufficient cost recovery for PG&E to implement an end-state billing system with Capability 5, PG&E will meet and confer with the Joint CCAs and may, if necessary, seek a Rule 16.6 extension request associated with those Settlement Agreement provisions.

Capability 6. Capability to implement structured change management with advance notice for material changes, testing, and coordination that includes and does not adversely impact CCA operations.[9]

Capability 7. Capability to execute utility-directed customer rate changes, including required outbound transactions, within Settlement-defined timeframes or other mutually agreed upon timelines.[10]

Capability 8. Capability to process EDI transactions in a manner that removes data discrepancies and transaction order-of-operations issues.[11]

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[9] PG&E's ability to deliver the Settlement Agreement provisions in Settlement Agreement Section 3.4.f is contingent on an end-state billing system with Capability 6. If the Commission does not approve sufficient cost recovery for PG&E to implement an end-state billing system with Capability 6, PG&E will meet and confer with the Joint CCAs and may, if necessary, seek a Rule 16.6 extension request associated with those Settlement Agreement provisions.

[10] PG&E's ability to deliver the Settlement Agreement provisions in Settlement Agreement Section 3.4.g is contingent on an end-state billing system with Capability 7. If the Commission does not approve sufficient cost recovery for PG&E to implement an end-state billing system with Capability 7, PG&E will meet and confer with the Joint CCAs and may, if necessary, seek a Rule 16.6 extension request associated with those Settlement Agreement provisions.

[11] PG&E's ability to deliver the Settlement Agreement provisions in Settlement Agreement Section 3.4.d is contingent on an end-state billing system with Capability 8. If the Commission does not approve sufficient cost recovery for PG&E to implement an end-state billing system with Capability 8, PG&E will meet and confer with the Joint CCAs and may, if necessary, seek a Rule 16.6 extension request associated with those Settlement Agreement provisions.

APPENDIX B

TABLES ADAPTED FROM THE DIRECT TESTIMONY OF KYRA J. COYLE ON BEHALF OF THE JOINT CCAS

Table 6: Additional Data Needed by CCAs in End-State PG&E Billing System[12]

Data File	Description
810 Files for "Rate Ready"[13] Accounts	An 810 file is an EDI file type that consists of a detailed customer invoice (*e.g.*, it includes all the separate transactions that comprise the total bill). Currently, for "Rate Ready" accounts, CCAs do not receive detailed invoice files from PG&E.
Adding the "Billed To" Date in 4013 Files	A 4013 file is an Excel/CSV file type that consists of a weekly snapshot of all active accounts in a given CCA territory (also referred to as a "Customer List"). Currently, this file type does not include a "billed to" date (*i.e.*, the last date PG&E billed the account).
Including "White Bill" Data on "Blue Bills" for Solar/Storage Customers	PG&E currently does not include the detailed information from its "white bills" in its regular "blue bills" for solar/storage customers.
Hourly and Sub-Hourly Billing Interval Data	PG&E Electronic Data Interchange (EDI) billing transactions still only provide scalar usage aggregated by time-of-use (TOU) period, unlike SCE and SDG&E which have included interval data for approximately 10 years.

[12] The Settling Parties have intentionally omitted recommendations regarding expected versus sent usage/account reporting and daily API pushes sharing 4013 data from this Partial Settlement Agreement.

[13] There are two types of billing available to PG&E CCAs: "Rate Ready" and "Bill Ready." "Rate Ready" accounts operate as follows: the CCA gives PG&E its rates, and PG&E then uses its billing system to calculate the invoice for CCA services. In contrast, "Bill Ready" accounts operate as follows: PG&E sends the CCA/CCA Data Manager its usage data, and then the CCA/CCA Data Manager calculates the invoice amount and sends PG&E an invoice to be placed on the consolidated bill.

Table 7: Data Quality Fixes Needed in End-State PG&E Billing System[14]

Data Quality Issue	Description of Data Quality Problem	Data Quality Solution
No Clear Process for Resolving Unbilled Invoices (810 Files)	An 810 file is an EDI file type that consists of a detailed customer invoice. It is currently used for "Bill Ready" accounts; per the Joint CCAs' suggestion in Table 6 above, 810s should be provided for "Rate Ready" accounts as well. Currently, PG&E does not adhere to any clear process for resolving unbilled 810 files. These are accounts that are billed by the CCA, but there is no acknowledgement from PG&E if CCA charges have been presented to the customer.	There should be an established, enforceable service level expectation that PG&E must provide full resolution within three business days once it receives notice from a CCA of unbilled invoices. This will ensure CCAs can get the revenues they are due in a timely manner.
Inconsistency in Classification of Rate Changes (814 Files)	An 814 file is an EDI file type that provides account attributes. PG&E has a practice of inconsistently classifying account rate changes—sometimes it classifies them as an "814 Rate Change"; sometimes it classifies them as an "814 Enrollment"; and sometimes it classifies them as an "814 Other" transaction. This affects how these files are processed in automation and where they appear in reports.	Any rate change should be sent via an 814 file and classified as "814 Rate Change" to avoid confusion.

[14] The Settling Parties have intentionally omitted the recommendations regarding unauthorized invoice cancellation and a process for switching from rate ready to bill ready from this Partial Settlement Agreement.

Unclear Drop/Enrollment Transaction Data	PG&E has a practice of communicating about all customer drops and enrollments via 814 transactions (the EDI file type that provides account attributes). When there are multiple drop/enrollment transactions on the same day for an account, PG&E does not clearly differentiate between the transactions with precise date/time stamps or indicate the final state (*i.e.*, "Active" or "Closed") of the account.	PG&E should clearly differentiate between all drop/enrollment transactions with precise date/time stamps and indicate the final state (*i.e.*, "Active" or "Closed") of the account.
Inconsistent Communication of Usage Data	PG&E is inconsistent in how it sends customer usage data to the CCAs. Sometimes PG&E sends usage data via EDI, but other times it states it cannot do so, and must instead provide the data via spreadsheet or via its green button AMI platform.	PG&E should send all usage data via EDI. This will streamline data transfer and minimize significant additional work on the CCA side.
Usage Data Sent Without Enrollment Data	PG&E often sends CCAs customer usage data without any corresponding enrollment data for the customer account. When the CCA receives usage without an enrollment, CCAs are unable to load that usage data into their billing systems without manual follow-up.	PG&E should be required to consistently send 814 files whenever a new customer enrolls.
Errors in PG&E Files Sent to CCA Banks	Currently, PG&E's process for sending credit and debit transactions to CCAs' banks is problematic. PG&E limits the number of transactions it sends in one file, and it sends all credit transactions first, followed by all debit transactions. This causes issues with file receipt and processing.	PG&E should be required to streamline its process for sending files to CCAs' banks, including by sending all transactions at once (without dividing credit and debit transactions).

Inability to Audit Rate Ready Accounts	CCAs are unable to audit Rate Ready customer bills because CCAs do not receive detailed invoice files from PG&E for these accounts.	PG&E should ensure CCAs can audit bills for Rate Ready customers. This could be achieved (1) if PG&E provides 810 files for these accounts, as proposed in Table 6 above, or (2) if PG&E provides more information via its 248 files (billing confirmation files) associated with the Rate Ready accounts.
Incorrectly Sending Both Interval and Scalar Usage	There are two types of usage data PG&E can provide: interval read (15 minute or hourly data for entire billing period) or scalar read (total kWh per billing period, sometimes broken up between TOU buckets). PG&E at times sends scalar data and then follows up later with interval data for the same accounts. This is unnecessary and causes manual work on the CCA side.	PG&E should only send one type of usage data per account per billing period. Per the recommendation regarding interval data in Table 6 above, PG&E should always be sending *just* interval data.

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
WORKSHOP COMMENTS

Leanne Bober,
Director of Regulatory Affairs and
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Counsel to
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

July 9, 2026

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends that the Commission:

- Scope Track 3 broadly to enable consideration of alternative targeted solutions to recover costs for uneconomic legacy resources, allocation of PCIA resources, mechanisms to reduce volatility, and other proposals and structural frameworks for achieving indifference;
- Prioritize the following issues concerning modifying the existing PCIA methodology (in addition to concurrently addressing alternative indifference mechanisms) to immediately create more consistency and address PCIA rate volatility: (1) re-vintaging; and (2) modifying the Renewables Portfolio Standard (RPS) market price benchmark (MPB), but only to align the calculation methodology with the Resource Adequacy (RA) calculation methodology adopted in Decision (D.) 25-06-049; and
- Build into the schedule adequate time to allow parties to provide and evaluate data, and to develop proposals for modification of the PCIA.

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[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 Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S WORKSHOP COMMENTS

California Community Choice Association[2] (CalCCA) submits these comments pursuant to the *Administrative Law Judge's Ruling Authorizing Party Comments on Track Three Workshop and Related Issues*[3] (Ruling)*,* dated June 19, 2026.

I. INTRODUCTION

The California Public Utilities Commission (Commission) opened this proceeding to "consider . . . changes to the [existing] Power Charge Indifference Adjustment (PCIA)."[4] The OIR seeks to, among other things, "mitigate and respond to rate volatility" and "best ensure indifference among bundled and departed customers."[5] Discussions at the June 8, 9, and 15, 2026, Track 3 Planning Workshops demonstrate the wide range of potential indifference

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[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 Authorizing Party Comments on Track Three Workshop and Related Issues*, Rulemaking (R.) 25-02-005 (June 19, 2026).

[4] *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes,* R.25-02-005 (Feb. 26, 2025) (OIR), at 1.

[5] *Ibid*.

framework and/or PCIA modifications, and the varied perspectives of parties regarding those potential modifications. As the OIR highlights, modifications are needed given "the consistent occurrence of issues in individual ratemaking cases that are better addressed in a rulemaking."[6] Given the significant stakes for all ratepayers, the Track 3 scope must be broad enough to allow for adequate discussion of the merits and trade-offs of the various potential modifications. Equally as important is that parties have timely access to the data necessary to independently evaluate potential modifications and develop informed proposals of their own.

The following comments are organized as directed in the Ruling, addressing issues raised at the Workshop and responding to the ALJ Workshop Questions set forth in the Ruling. CalCCA incorporates herein its earlier Comments on the Track 3 scope,[7] and does not have additional comments on issues already addressed in those Track 3 Comments. CalCCA overall recommends the Commission:

- Scope Track 3 broadly to enable consideration of alternative targeted solutions to recover costs for uneconomic legacy resources, allocation of PCIA resources, mechanisms to reduce volatility, and other proposals and structural frameworks for achieving indifference;
- Prioritize the following issues concerning modifying the existing PCIA methodology (in addition to concurrently addressing alternative indifference mechanisms) to immediately create more consistency and address PCIA rate volatility: (1) re-vintaging; and (2) modifying the Renewables Portfolio Standard (RPS) market price benchmark (MPB), but only to align the calculation methodology with the Resource Adequacy (RA) calculation methodology adopted in Decision (D.) 25-06-049; and
- Build into the schedule adequate time to allow parties to provide and evaluate data, and to develop proposals for modification of the PCIA.

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[6] OIR, at 13-14.

[7] *See California Community Choice Association's Opening Comments on Administrative Law Judge's Ruling Authorizing Parties to File Comments on Issues to Address in Track 3,* R.25-02-005 (Mar. 27, 2026) (CalCCA Track 3 Ruling Comments); *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Authorizing Parties to File Comments on Issues to Address in Track 3,* R.25-02-005 (Apr. 10, 2026) (CalCCA Track 3 Ruling Reply) (together CalCCA Track 3 Comments).

II. CALCCA COMMENTS ON ISSUES RAISED AT WORKSHOPS

CalCCA addresses issues raised at the Workshops in response to the ALJ Workshop Questions in Section IV., below. CalCCA does not provide any comments on new issues for this proceeding, except for its recommendations in Section 4, below, related to Workshop Day 2.

III. CALCCA COMMENTS ON ISSUES THAT WERE RAISED IN EARLIER TRACK 3 COMMENTS

CalCCA does not have comments in addition to those raised in its Track 3 Comments at this time, which include:

- Adopting a broad scope for Track 3, including but not limited to all scoping items originally identified in the OIR;
- Resolving data access and confidentiality issues early in Track 3;
- Adopting a data access protocol requiring the scope and term of data set forth in CalCCA's Data Matrix; and
- Providing a minimum of six months following data production for analysis and proposal development by all parties.[8]

IV. CALCCA RESPONSES TO SECTION 1 OF THE RULING

A. ALJ Workshop Questions

1. Issues Discussed on Day 1: Structural Changes

a. Do the following topics have the potential for sufficient net benefits to warrant their inclusion in the scope of Track 3? If so, please provide a brief (one to two sentences) explanation of the direction you would like to consider with regards to this topic. Likewise, please identify if consideration of any topic should be considered mutually exclusive with others.

i. Targeted solutions to recover costs for uneconomic legacy resources

[8] *Ibid.*

CalCCA supports including in scope the identification of potential alternative solutions for recovering uneconomic legacy resource costs, as discussed at Day 1 of the Workshops. The scope can consider solutions such as, but not limited to:

- Securitizing all or part of legacy Utility Owned Generation (UOG) costs;
- Considering how to reduce the amount of UOG costs in the portfolio;
- Exploring third-party management of UOG resources to balance the incentives of portfolio management on behalf of all customers;
- Revisiting full or partial buyouts of PCIA obligations using a third-party portfolio valuation;
- Exploring ways to harness load growth to reduce the burden of PCIA costs;
- Holding a Request for Information (RFI) process to renegotiate or reassign expensive contracts with counterparties; and
- Enhancing IOU portfolio optimization through Bundled Procurement Plan (BPP) modifications.[9]

Each of these solutions has the potential to align incentives to facilitate fair competition among load serving entities (LSEs) and/or reduce the magnitude of PCIA costs for *all* customers. While the PCIA is primarily a cost allocation tool, the concepts outlined above have the potential to reduce overall costs associated with administering and managing the PCIA portfolio. Lowering these costs would reduce rates for bundled and unbundled customers alike.

ii. Revisiting allocation, in particular the potential for mandatory allocations

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[9] Lack of transparency around the IOUs' processes for making excess RA capacity and other attributes available to the market can raise concerns over portfolio optimization. Since PG&E's 2019 ERRA Compliance case, community choice aggregators (CCAs) have asked the Commission to set clearer standards in the IOUs' Bundled Procurement Plans (BPP) to ensure portfolio optimization. The Commission did not act on those requests until 2025 when it put the BPPs in scope in the Integrated Resource Plan (IRP) proceeding (R.25-06-019). Parties in R.25-06-019 are awaiting a Ruling instructing next steps in response to the IOUs' proposed modifications. If the Ruling clarifies that: (1) only the IOUs propose revisions to the BPPs; and (2) parties' roles are limited to commenting on the IOUs' ideas instead of proposing their own, then this issue should be in scope for the PCIA proceeding to enable stakeholders to propose BPP modifications as part of the Commission's consideration of how best to optimize IOU portfolios.

CalCCA also supports the Commission incorporating into scope revisiting the allocation of PCIA attributes (*i.e.*, RA, RPS, and greenhouse gas-free attributes), particularly the concept of mandatory allocations with transactability. Only mandatory allocation eliminates the need to rely on MPBs; voluntary allocation could still leave residual products that may need to be valued in some way. Aside from the Energy MPB, which uses a market-clearing price, all other attributes must use proxy prices calculated by Energy Division to estimate the MPB. These estimates, while a reasonable approach determined through a Working Group process in R.17-06-026, are subject to dispute and changing market conditions, which has introduced additional uncertainty into the PCIA along with rate volatility.[10] As an approximation of the costs of attributes, MPBs are inherently inaccurate and subject to disagreement. Avoiding a proxy calculation altogether by allocating the attributes would alleviate the need to continuously adjust estimation methodologies, saving Commission and LSE staff time and resources, and settling the ongoing, and potential future, disputes around the estimated value of attributes.

iii. Mechanisms to reduce volatility and stabilize rates

CalCCA supports the Commission considering mechanisms to reduce volatility and stabilize rates, including but not limited to considering revisions to the RPS MPB methodology to align with the new RA MPB methodology, and allowing stakeholder access to the data underlying the MPBs. *First*, the Commission should explore the concept of relying on a longer price-averaging period to calculate the Forecast and Final RPS MPB (three and four years, respectively, as recently adopted for the RA MPB in D.25-06-049) to reduce volatility. A record

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10 *See, e.g., Energy Division Staff Report of the 2024-2025 Resource Adequacy Market Price Benchmark*, R.25-02-005 (Feb. 26, 2025), at 5 ("The system RA Forecast and Final MPBs have seen the most volatility since the current PCIA MPB methodology was adopted in D.18-10-019…This RA price is reflective of a recent subset of RA transactions that may be driven by market power, as it does not appear that new RA projects are or would be this expensive.").

on this issue can be developed by directing Energy Division to issue a Staff Report analyzing the impact of calculating the RPS MPB in this manner. As discussed in Section 2.b., below, this Staff Report should allow interested stakeholders to review data inputs as well as the results of the analysis.

Second, the ability to engage in long-term planning empowers CCAs and IOUs alike to manage PCIA rate swings. To the extent the MPBs remain a key input to the PCIA, the Commission should identify ongoing information-sharing mechanisms to ensure that stakeholders have access to the data to empower improved forecasts of the MPBs.

iv. Other proposals or structural frameworks for achieving indifference that may produce greater net benefits for ratepayers and promote competition among LSEs

CalCCA supports the Commission exploring other proposals and structural frameworks for achieving indifference that produce greater net benefits for ratepayers and promote competition among LSEs. Track 3 should therefore be scoped to allow for parties to identify additional framework modifications to the PCIA, and alternative and viable methods to ensure indifference outside of the PCIA framework. While the current paradigm has its merits and is the product of a working group process, it is not without persistent issues, systematic volatility, and growing pains. A PCIA proceeding considering modifications to the PCIA has been open for nine of the last ten years, demonstrating the complexity in establishing robust mechanisms to ensure indifference. The time is right to zoom out and consider alternative approaches to achieving indifference that may provide greater net benefits for all customers and promote competition among LSEs.

b. If these issues are included in scope, and parties are permitted to make proposals for structural changes, how much time to develop proposals is necessary?

The Commission should provide six months after parties receive relevant data for proposals. This allows for sufficient time to carefully craft, analyze, and test proposals, ensuring they are conceptually sound and robust in the context of real data.

c. If these issues are included in scope, should they be addressed concurrently with, before, or after other issues?

The Commission should address the issues outlined above concurrently with other issues, but only after relevant data are made available to all parties.[11]

2. Issues Discussed on Day 2: Refinements to PCIA and ERRA

a. What are your 2-3 highest-priority issues?

CalCCA interprets this question to seek high priorities regarding *PCIA and ERRA modifications* that can be immediately addressed at the outset of Track 3, without the need for additional data access. Overall, a high priority for CalCCA is considering alternative indifference structures, as discussed in Section IV.A.1., above. However, in considering refinements to the current PCIA framework that can be addressed now and concurrently with considering alternative indifference structures, the Commission should prioritize re-vintaging and modifying the RPS MPB.

First, re-vintaging has been addressed without resolution in other Commission proceedings, which found that the issue should be addressed in a statewide rulemaking.[12] In

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[11] Following standard Commission rules and practices around confidential information if appropriate.

[12] *See, e.g.,* D.23-11-069, *Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company*, A.21-06-021 (Nov. 16, 2023), at 511 ("Finally, with respect to Joint CCAs' framework proposal, the Commission also declines to consider it in this proceeding, as this would require a thorough examination of the complexities involving the current vintaging framework and how costs are allocated as part of the PCIA. This review would best take place in a broader proceeding in which other utilities and stakeholder positions may be considered."); *see also* D.24-12-074, *Decision Adopting the 2024 Test Year General Rate Cases of Southern California Gas Company and San Diego Gas & Electric Company*, A.22-05-015 (Dec. 23, 2024), at 408 ("Generally, matters that are of statewide relevance across IOU territories should be addressed in a statewide proceeding that applies to all relevant regulated IOUs,

addition, PG&E requested to pause the schedule in its Helms Uprate Application until the Commission decides on any modifications to vintaging in this proceeding.[13] The Commission has not yet ruled on PG&E's motion. *Second*, there is a substantial record in this proceeding on changes to the RA MPB that can be built upon for the RPS MPB. A Staff Report on the RPS MPB can also inform the record. Given these circumstances, each of these issues is ripe to be placed in scope at the beginning of Track 3, concurrent with the Commission considering overall changes to the indifference framework.

b. What is the level of complexity in record development anticipated to address each of the priority issues? For instance, what analysis is necessary?

The re-vintaging issue has been addressed by parties without resolution in other Commission proceedings, as noted above.[14] Those proceedings provide background for the Commission to address the re-vintaging issue, and legal briefing could potentially be sufficient to address this issue. The Commission, however, must fulsomely decide both the standard for re-vintaging and the appropriate venue to consider re-vintaging that allows all parties to adequately review proper cost allocation.[15]

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where a proper record can be developed and participation of all stakeholder interests can be considered, rather than in a utility specific GRC proceeding.").

[13] *See Joint Motion of Pacific Gas and Electric Company (U 39 E) and Californians for Green Nuclear Power to Hold Phase II in Abeyance Pending Resolution of Issues in Rulemaking 25-02-005*, Application 23-12-014 (Jan. 16, 2026).

[14] *See* n. 12, *supra*.

[15] If all policy issues regarding re-vintaging are comprehensively addressed, CalCCA agrees with the assessment of the Joint IOUs in their OIR Opening Comments that the issues can be addressed in this rulemaking via legal briefing. *See Joint IOU Opening Comments on the Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes,* R.25-02-005 (Mar. 18, 2025), at 29; *see also California Community Choice Association's Reply Comments on the Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes,* R.25-02-005 (Apr. 2, 2025), at 33-37 (stating that vintaging questions are broader than simply the standard for re-vintaging given no proper forum exists for adequate review of the vintaging treatment of a resource).

Regarding aligning the RPS MPB with the RA MPB, as noted above, a record on this issue could be developed by directing Energy Division to issue a Staff Report analyzing the impact of calculating the RPS MPB using the same longer price-averaging period relied on to calculate the RA MPB. To provide transparency, the Commission should anonymize RPS transaction data used by Energy Division to calculate the RPS MPB and provide the data to parties through Reviewing Representatives to allow parties to perform and present their own analyses.

3. Issues Discussed on Day 3: Data Access

a. Part 2 of this ruling contains a template for a list of data access issues that would be filled out and included in the joint case management statement. Do you suggest any changes to this template?

The template should be amended to add a column after the data type to identify the timeframe of the data desired. Both the data type and the timeframe of that data are necessary details. The Commission should also add a column to the template that indicates whether the listed data is public, or confidential and requires a reviewing representative. For example, market-sensitive data are confidential for three years into the future and one year in the past.[16] Therefore, data of one type could be confidential for certain record years and public for other record years. Adding the public or confidential indicator as a column would provide necessary granularity to understand the status of information.

b. If other parties have made proposals for data access that you oppose, identify an underlying motivation for that proposal that you share and/or support.

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[16] *Interim Opinion Implementing Senate Bill No. 1488, Relating to Confidentiality of Electric Procurement Data Submitted to the Commission*, R.05-06-040 (June 29, 2006), at Ordering Paragraph 1.

CalCCA appreciates the Joint IOUs' data offer presented in their April 10 Track 3 Scope Reply Comments.[17] Based on this offer and the comments made by the Joint IOUs during Day 3 of the Workshops, CalCCA believes the parties have taken a constructive and necessary first step towards resolution of data issues. Most importantly, CalCCA appreciates the Joint IOUs' recognition that CalCCA (through its reviewing representatives) requires access to this data, and their willingness to use the standard Model NDA. The proposed data offered by the IOUs, however, is not sufficient to meet CalCCA's needs for developing proposals.

CalCCA's Data Matrix was developed to identify the information necessary to independently: (1) analyze the makeup of the IOUs' PCIA-eligible resource portfolios at the individual contract and resource level and their historical performance; (2) model PCIA charges; (3) model the impacts of any changes to the MPBs; and (4) develop proposals for modifications to the PCIA calculation. The Joint IOUs' data offer generally acknowledges these legitimate analytical needs which provides an important foundation for resolving the remaining issues. Their offer addresses most of the major categories of data identified by CalCCA. However, significant differences exist between the parties regarding how certain data will be presented, and the time periods applicable to the data requested.

Given the Joint IOUs' recognition of CalCCA's legitimate need for the requested information, CalCCA remains confident that the parties can agree on a reasonable approach. CalCCA outlined several of its requested refinements to the Joint IOU offer during the Day 3 Workshop, and has included this information in Table 1 below. While the parties are substantially aligned on the objectives of a data access framework, CalCCA remains confident that the meet-and-confer framework will provide an opportunity to address the remaining issues.

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17 *See Joint IOU Reply Comments on the Administrative Law Judge's Ruling Authorizing Parties to File Comments on Issues to Address in Track 3,* R.25-02-005 (Apr. 10, 2026), at 12 and Appendix A.

Table 1: CalCCA Requested Refinements to Joint IOU Offer of Data

Missing Information	***Additional Information Needed from IOUs***
Forecast information beyond 2026 (preventing PCIA calculation beyond 2026)	All PCIA inputs (*e.g.,* resource cost, energy and capacity output, CAISO revenue, bundled and unbundled customer load/PCIA billing determinants) *beyond 2026*
Provides some, but not all requested information on contracts and UOG	ID number, CAISO resource ID, solicitation, CPUC authorization, resource type/products, resource technology, location, PCIA vintage, contract amendment date(s), VAMO eligibility, GHG-free eligibility, RA classification/location, qualifying RA capacity (MW counted toward RA requirement), UOG depreciable life, UOG hydro FERC license term
Cost information for UOG resources	O&M, fuel costs, GHG costs, depreciation expense, capital additions, administrative costs (procurement management), annual revenue requirements
Forward market prices	For energy, RA, RECs, GHG free attributes
Procurement planning documents	Bundled Procurement Plan, RPS Procurement Plan
Net market value calculations	Net market value calculations
Provides some historical information but is missing other historical components affecting PABA	Sold and unsold RA, sold and unsold RPS, approved UOG revenue requirement, bundled and unbundled customer revenue/sales, miscellaneous CAISO revenue/costs, miscellaneous other costs

c. How much time is needed between the issuance of the Track 3 Scoping Memo and a deadline for load serving entities to meet and confer on data access issues and subsequently file a joint case management statement?

To provide sufficient time for parties to meet and confer on data access issues, the Commission should allow 60 days following issuance of the Track 3 Scoping Ruling and Memo to file a Joint Case Management Statement. This schedule will provide sufficient time for parties to meet several times and prepare a proposal for the Commission's consideration.

While CalCCA believes time will be needed to refine the details of data access, the more important scheduling consideration is the amount of time CalCCA will have to analyze the data once it is produced. The Joint IOUs have had, and will continue to have, the ability to develop and test proposals throughout this process, as they have since the outset of this proceeding. To ensure a fair and informed Track 3 process, the Commission should be prepared to resolve data access issues before setting any additional substantive timelines or to make timelines contingent on data access resolution.

V. 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,

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

July 9, 2026

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S INFORMAL RESPONSES IN ADVANCE OF THE JULY 23, 2026, INTEGRATED RESOURCE PLANNING PROCUREMENT COMPLIANCE WORKSHOP

I. INTRODUCTION

The California Community Choice Association[1] (CalCCA) appreciates the opportunity to submit the following informal responses pursuant to the May 20, 2026, *MTR Compliance Staff Proposal Workshop Notice*; the email communication of June 17, 2026, *Procurement Compliance Staff Proposal Workshop Questions* (June Email); and the email communication of June 24, 2026, *R2506019 2025 IRP OIR: Procurement Compliance Staff Proposal Workshop Questions*, granting an extension from July 7, 2026, to July 14, 2026, to submit responses to the MTR Procurement Compliance Workshop questions.

The Integrated Resource Planning (IRP) proceeding's Scoping Ruling states that this proceeding will consider any necessary refinements to compliance requirements with prior procurement orders, "including elements of program design, implementation, compliance, and enforcement," such as "any necessary clarifications to the 'good faith efforts' standard first mentioned in [Decision (D.)]21-06-035."[2]

Community Choice Aggregators (CCAs) are committed to bringing new clean capacity online to advance the clean energy transition, ensure reliable electric service, and meet the needs of their communities. As of November 19, 2025, CCAs have secured more than 21,000 megawatts (MW) of new-build clean capacity through long-term power-purchase agreements (PPA).[3] The current procurement environment is challenging, however, with many variables outside of the control of load-serving entities (LSE) and developers which can impact new resource deployment. These variables include but are not limited to market conditions, permitting delays, interconnection challenges, and changes in federal policies.

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[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] *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking (R.) 25-06-019 (Oct. 28, 2025), at 10, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M585/K485/585485746.PDF.

[3] California Community Choice Association, https://cal-cca.org/cca-renewable-energy-map-and-list-of-ppas/.

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For these reasons, the California Public Utilities Commission (Commission) should seek to refine its compliance framework in a manner that (1) preserves robust incentives to comply while providing flexibility, when necessary, in recognition of exogenous factors impacting progress towards compliance, and (2) ensures clarity and consistency in its application. Importantly, the "good faith efforts" standard should be retained and clarified so that the definition of, and process for demonstrating, good faith efforts are clear. The Commission should also minimize modifications to rules and guidance already provided in prior decisions and frequently asked question (FAQ) documents, given LSEs have already conducted a significant amount of procurement under this guidance.

Through the upcoming Workshop and Staff Proposal, the Commission should seek to establish a procurement compliance process to apply to pending and future compliance determinations that:

- ✓ Adequately balances the need for robust enforcement to incent resource development in compliance with procurement directives and the need for flexibility when exogenous factors outside the control of an LSE negatively affect compliance and/or present significant ratepayer affordability concerns;
- ✓ Establishes a clear and well-defined application of the "good faith efforts" standard that: (1) preserves the integrity of the overall procurement incentive framework, and (2) allows the Commission to identify LSEs that make reasonable procurement efforts but are unable to comply due to extenuating circumstances that penalties will not prevent; and
- ✓ Avoids upending rules and expectations that have already been established through prior Commission orders and/or Energy Division guidance.

II. CALCCA RESPONSES TO QUESTIONS

In the June Email, Energy Division presents a series of questions for parties' consideration in advance of the July 23, 2026, Workshop. CalCCA has provided recommendations and answered these questions below to the best of its ability with the information currently available. CalCCA reserves the right to revise its answers based on the additional context of the forthcoming Workshop discussions and the Staff Proposal.

Section 1. Net CONE

1.1 Should a mechanism other than Net Cost of New Entry (CONE) be used to determine the penalty for procurement non-compliance? If yes, what mechanism?

The Commission should maintain the use of Net CONE as the basis for any penalty for procurement non-compliance. The Commission introduced Net CONE as the basis for the penalty in D.21-06-035 (the Mid-Term Reliability or MTR Order),[4] and to date, has not communicated any perceived deficiency with this approach. Net CONE represents the cost of developing a new resource, aligning with the purpose of the Commission's procurement directives, and tracks market conditions to ensure the penalty price adequately incents compliance without being overly punitive. The Commission should establish a regular cadence and transparent process for updating Net CONE so that LSEs have a clear understanding of the penalty amount for each tranche of procurement ordered.

There are, however, potential scenarios that could demonstrate real, tangible effort to make up for situations out of the LSE's control that are missed in any specific definitions for the alternative compliance pathway and good faith efforts standard. As such, while Net CONE should be the basis for the penalty, the application of Net CONE should be considered in light of mitigation efforts that do not technically apply within the good faith efforts or alternative compliance pathways' definitions.

1.2 Should the penalty be proportionate to the Load Serving Entities (LSE's) load served so that its ratepayers are not disproportionately and inequitably affected? Explain.

The penalty established in the MTR Order and subsequent orders is already proportionate to load because the procurement obligation is established based on load and the penalty is applied to the MW deficiency relative to its obligation. The Commission should not modify this methodology. Depending on the good faith efforts showing, the penalty should be reduced or waived to reflect an individual LSE's good faith efforts showing and be commensurate with any market impact the LSE's shortfall created.

1.3 It is proposed to replace existing language that sets the procurement penalty amount (Net CONE) -- set at the price of a battery energy storage facility-- to a specific dollar amount. Is there a reason that a specific dollar amount should not be provided to replace Net CONE? If yes, explain why?

The Commission should retain the Net CONE penalty rather than applying a specific dollar amount for the reasons described in response to question 1.1. Unlike a penalty tied to a specific dollar amount, Net CONE can be periodically updated through a clear process and regular schedule to ensure that the penalty reflects relevant market conditions and adequately incents compliance.

1.4 Should application of procurement penalties be determined annually following June 1st?

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4 D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability* (2023-2026), R.20-05-003 (June 30, 2021), Conclusion of Law 26, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF.

Penalty application should be: (1) based on the final verified deficiency for each compliance period; and (2) preceded by a good faith efforts process for each compliance period. Compliance assessments, and any future procurement orders, should be based on, at minimum, three-year tranches. Annual compliance periods are too granular for the variable nature of the new resource development process. Resources' commercial operation dates (COD) are dependent on a wide variety of factors that can result in schedule changes that, while minor, could subject an LSE to non-compliance with a strict June 1 deadline. For example, a resource may have an original online date of June 1 and experience a delay of one or two months. Requiring an LSE to procure replacement capacity or penalizing an LSE for such a delay would simply add costs rather than providing the desired incentives. Longer term tranches meet the same objective of bringing new capacity online, while providing LSEs with flexibility to manage project delays, cancellations, and other changes to the greatest extent possible within a reasonable amount of time.

Section 2. Good Faith Effort

2.1 With the implementation of the alternative compliance approach, it is proposed to sunset the "good faith effort" policy. Is there a need for a complementary policy for the existing alternative compliance approach? Why or why not?

The good faith efforts standard remains necessary, should be retained, and complements the alternative compliance mechanism. The alternative compliance mechanism alone cannot fully account for unforeseen or extraordinary circumstances affecting procurement over a multi-year horizon, as there are many factors outside the control of LSEs and potentially developers that can impact project viability and timelines. For example, a project may experience a sudden cancellation just prior to a compliance deadline, necessitating an LSE to execute a new contract to replace it. This situation could occur even if the LSE conducted robust procurement outreach, bid review, and vetting of counterparties. In addition, as CalCCA understands it, the alternative compliance approach only applies to project delays, not project cancellations.[5] The "good faith efforts" process should therefore be clarified to explicitly cover cancelled projects with a replacement project with a COD of up to three years later than the failed project.

In addition, the Commission has issued procurement orders for "resource attributes" that can only be met by a limited set of technologies that are not abundantly available in the

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[5] D.25-09-007 clarifies that an LSE will be deemed in compliance with all of the procurement requirements of D.21-06-035 and D.23-02-040, as modified by D.24-02-047, if the LSE demonstrates the following: (1) the LSE sufficiently executed long term contracts that meet the applicable MTR procurement requirement; and (2) the LSE has met its month-ahead system resource adequacy (RA) requirement for each month that the procurement is delayed, by the deadline for any RA deficiency.

pipeline.[6] LSEs may need to rely on alternative compliance approaches and demonstrations of good faith efforts until contracts can be executed for these difficult-to-procure technologies. A compliance program that lacks flexibility to account for circumstances outside an LSE's control can unnecessarily increase costs to ratepayers by forcing excess procurement or triggering penalty costs to address temporary gaps that are expected to be resolved in the near-term. Further, it can create opportunities for sellers to exercise market power by incentivizing LSEs to secure compliance at any cost.

The Commission should also extend the alternative compliance approach to cover project delays, cancellations, and other scenarios. In the example of a project cancellation close to a compliance deadline, the reliability impact of project cancellation/replacement is the same as if the project was instead delayed. If an LSE finds a replacement resource that can reach COD three years after the compliance period, and the LSE fully meets its RA obligations during that three-year period, the impact of the alternative compliance mechanism applied to the project cancellation/replacement is the same as if the project was instead delayed by three years.

However, the usefulness of an alternative compliance approach may be limited when the resource adequacy (RA) market is constrained, as it was in 2024. Additionally, the alternative compliance approach may not foresee all cases warranting a review of good faith efforts and does not fully consider whether LSEs take reasonable efforts to comply. A good faith standard will allow the Commission to distinguish between LSEs that did not make reasonable procurement efforts and those that acted diligently but were constrained by factors outside their control such as market conditions, permitting delays, or interconnection challenges.

2.2 Should "good faith effort" be defined? If yes, what should be the definition of "good faith effort". ***Note: Any definition should be objective and measurable.***

"Good faith effort" should be defined as documented, timely, and reasonable procurement actions undertaken by an LSE to meet its procurement obligation, which could include a combination of the following:

- Did the LSE conduct timely solicitations (*e.g.*, RFO)?
- Did the LSE pursue means other than an RFO to bilaterally procure new resources, if permitted by the LSE's governing board?
- Did the LSE reasonably pursue offers to negotiate acceptable terms and conditions?

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[6] The MTR Order directs LSEs to procure long-duration energy storage (LDES) and firm zero-emissions resources. D.26-02-057 directs LSEs to procure LDES or clean firm resources with capacity factors of 80 percent or more and not use-limited.

- Did the LSE have reasonable terms and conditions to bind the seller to completing the project and key milestones on time and within budget?
- Did the LSE have a reasonable method to ensure sufficient expertise of the developer to complete the project?
- Did the LSE make reasonable efforts to address potential project failures in addition to terms and conditions binding the seller to completing the project given the expertise of the developer?
- Did the LSE make reasonable efforts to meet alternative compliance mechanisms available to them?
- Did the LSE sign a contract with a project to replace the capacity from an initial project that ultimately failed due to circumstances outside of the LSE's control?
- Despite all of the above:
    - Did the LSE receive no bids;
    - Did the LSE receive bids insufficient to meet its procurement obligation;
    - Did the LSE receive bids indicative of market power defined as 1.2 times Net CONE for the compliance category the resource is being used for (e.g., generic MTR – battery storage Net CONE, long-lead time (LLT) MTR – geothermal Net CONE);
    - Did the LSE receive bids or negotiated contract terms with unreasonable and/or non-conventional terms and/or conditions (*e.g*., terms and conditions that unduly burden the buyer, such as a contract with a generating resource with an expected life of 20-25 years with a cost at or near net CONE recovered over 10 years with no option for contract extension, a contract with significant LSE exposure to additional cost liability);
    - Was the developer unable to complete the project despite being a reliable developer;
    - Were reasonable offers to replace the contract with on time delivery not available; or
    - Did other circumstances prevent the LSE from meeting its obligation?

These criteria are intended to maintain the integrity of the compliance incentive framework and, as described above, distinguish between LSEs that did not make reasonable procurement efforts and those that did. The procurement process, from contracting, development, permitting, and interconnection, is complex with many co-dependent variables impacting a project's progression. Without a good faith efforts standard to account for these circumstances, ratepayers can be subject to unnecessary costs either through unnecessary procurement costs to backfill temporary or unavoidable compliance gaps or through penalty costs arising from circumstances outside the LSEs' control.

2.3 With the implementation of the alternative compliance approach, please explain why the "good faith effort" policy may still be necessary. Provide an example scenario.

As described in response to question 2.2, the resource development process from contracting to COD involves a wide range of factors beyond the LSE's control that can impact a project's progress. Imposing strict liability frameworks can create or exacerbate supplier market power, and provide suppliers with leverage to negotiate unfavorable contract terms or act in "bad faith."

There can be unforeseeable circumstances that lead to project delay or failure, especially for LLT resources in which: (1) the technology may be new; (2) new transmission may be delayed/not come to fruition; (3) project deliverability or interconnection priority that was indicated as highly likely may unexpectedly evaporate; (4) financing may not materialize due to challenges related to interconnection or transmission development issues mentioned earlier; or (5) other reasons. These issues may not become obvious until development has progressed, and LSEs would not have all the information available to make decisions at the time of contract execution. LSEs should have an opportunity to demonstrate good faith efforts before being assessed a penalty due to these factors.

In addition, the alternate compliance path is dependent on compliance with RA to address a delay in a resources COD. Given that the Commission recently issued an order to procure additional resources, the complexity of the hourly slice-of-day (SOD) mechanism, and the anticipated closure of 2,200 MW of 24x7 RA, the potential for a scarce RA marketplace exists that could duplicate the RA insufficiency seen in 2024. The RA program does not have a "good faith effort" process for system RA, and absent a good-faith effort process from both the RA and IRP programs, the LSE could experience market power from developers of new resources and/or market power from existing resources needed to fulfill the alternative compliance mechanism of meeting RA. Each of these outcomes would have significant impact on customers. A properly developed safety relief mechanism will address such an impact while providing incentive to develop new resources.

Section 3. Definition of "Online"

3.1 The proposed definition of online is "the resource is delivering power to the grid and contracted to deliver by the specified compliance tranche date." Other than Commercial Operations Date (COD), are there any other determinants that meet the proposed definition?

Further context may be necessary around the problem this question is attempting to solve to fully answer this question, but generally, the CAISO COD and Commercial Operations for Market (COM) meets this definition. The CAISO COD and COM signal that a resource is capable of delivering power to the grid and can occasionally occur before contracted delivery date.

3.2 Can a resource receive a Commercial Operations for Market (COM) notice without ever receiving a COD notice? Please explain.

CalCCA's understanding is that a resource can receive a COM without receiving a COD, though it does not happen often. As with question 3.1, further context is necessary to answer this question fully.

3.3 What modifications or upgrades can or should occur that would result in incremental capacity of a resource? Is there anything else other than physical modifications or upgrades that can result in an increase in a resource's deliverability capabilities?

Most modifications are physical, for example adding batteries, expanding solar panels, drilling new wells for geothermal, increasing inverter capacity, or repairs to degraded facilities that result in the facilities' output increasing above the level modeled in procurement orders. Non-physical upgrades can include software upgrades that enhance unit efficiency or an increase in use-limited resource capacity (*e.g.*, new air permit). Upgrades and modifications that result in incremental capacity should be countable towards procurement orders.

3.4 When looking at how energy and storage resources can be paired, are there negative impacts to a resource having intermittent pairing with an energy resource that does not fully span the contract term of the storage? Explain.

No, LSEs may choose to contract a generation resource and a storage resource differently for a variety of reasons, including procurement needs and costs. LSEs and their developer counterparties are in the best position to determine the contract length necessary to get new resources built. The Commission should assume that if the initial term of the contract was sufficient for the resource to be built (*i.e.*, long enough duration with sufficient capital recovery), then its pairing with another resource is not relevant to the efficacy of the resource.

Section 4. Capacity Factor

4.1 What engineering assessment calculation methods can be used by an LSE to demonstrate an 80% capacity factor? Explain specific calculation methods and how this would be demonstrated.

LSEs should be able to demonstrate that the contracted resource is capable of producing at no less than an 80 percent capacity factor either through the contract or engineering assessment, instead of after the fact on-going review of the facility's output. Developers typically provide guaranteed energy production or engineering assessment in the PPA to ensure LSEs receive the energy they paid for. It may not be possible for an LSE themselves to demonstrate capacity factors in operation.

4.2 Should the 80% annual capacity factor requirement be determined by: (a) An average annual capacity factor of 80% across the entire term of the contract or (b) An annual capacity factor of 80% in at least the first year of a contract? Explain.

See response to question 4.1 above. LSEs are required to procure resources that satisfy specific contract requirements. Counterparties are responsible for meeting their contractual obligations. LSEs should not bear compliance risk arising from a counterparty's failure to perform.

4.3 Should there be a different definition for capacity factor? Why?

No. The Commission has already defined capacity factor and should not change the definition in the midst of LSE compliance with a procurement order. Procurement contracts require months or years to negotiate, permit, finance, and construct. In this process, the Commission should recognize that procurement decisions already underway cannot easily be modified to fit a new framework. The Commission should therefore maintain existing rules and guidance related to resource eligibility.

4.4 Due to the Long Lead Time (LLT) requirement for the ratio of the actual amount of electrical power produced by a generating unit and the required continuous generation at full maximum discharge for 24 hours a day, 7 days a week, over a year, should there be a varied definition of capacity factor for LLT resources?

No. See response to question 4.3. The Commission has already defined capacity factor and LLT and should not change the definition in the midst of LSE compliance with a procurement order.

Section 5. Resource Delays

5.1 If a resource is delayed or contracted with a later online date and paired with a bridge or alternative compliance pathway, should the LSE get to apply the selected tranche Effective Load Carrying Capability (ELCC), or should they be required to use the later ELCC associated to the online date?

For the same reasons described in response to question 4.3, the ELCC values should align with the tranche the resource is intended to comply with. This is consistent with existing procurement order guidance in FAQ 5.3.8 from Version 6.1 (June 17, 2025) and FAQ from the November 14, 2025, Office Hours.

5.2 How should resource delay be defined? What evidence can be provided to prove a resource delay?

Resource delay should be defined as a resource not meeting its COD by the compliance date. Developers can provide official notices about delays based on contractual processes, and those notices would contain reasons for delays.

5.3 If a resource is delayed and a long-term contract is not procured, how should the ELCC for the initial tranche be applied?

Generally, as described in response to question 5.1 above, the ELCC value that is applied to a resource should align with the compliance tranche the LSE chooses to count the resource towards. This may require delayed resources to be considered in ELCC calculation updates used for future tranches to ensure there is no over-dependance on a particular type of resource. This is likely to occur naturally as the Commission must provide ELCCs early in the process to enable LSEs to perform meaningful procurement activities. With that being said, additional specificity around the purpose of this question and the information the Commission is seeking would be helpful to more fully answer this question.

5.4 Should the alternative compliance mechanism cure a deficiency gap for a resource that is contracted for a later date, or should the alternative compliance mechanism only close the gap if a resource was originally contracted for an earlier online date?

The alternative compliance mechanism should cure a deficiency gap for a resource that is contracted for a later date. There are many reasons why a gap like this could exist. For example, an LSE may have a resource that is contracted to come online June 1, 2025, but the contract is terminated at the last minute due to circumstances outside the LSE's control. The next earliest long-term contract that the LSE may be able to procure might not have an online date until June 1, 2027. Alternatively, an LSE may conduct reasonable efforts to procure to an attribute-based procurement requirement (*e.g.*, the MTR's LLT requirement) and the earliest online date for resources that meet this requirement occurs after the compliance deadline, due to supply chain, interconnection timelines, or other factors. In these cases, LSEs should be able to demonstrate that they have complied with the alternative mechanism, which ensures the LSE continues to meet its reliability requirements during the period of the deficiency gap while continuing to bring a delayed resource or new resource online to close the gap.

5.5 What documentation should be required to demonstrate a resource was originally intended for an earlier contract date other than an executed contract? Please explain.

Contracts should provide sufficient documentation to demonstrate the original and revised contract dates.

5.6 If a resource is delayed, can an LSE negotiate language that requires the delivery period be extended to maintain a 10- year tenure?

Yes. LSEs generally have the ability to negotiate the tenure of the delivery period. Typically, if a project is delayed, the delivery period will shift to maintain a 10-year duration.

Section 6. Issuance of Citations

6.1 Since citations are currently issued publicly, is there a reason that procurement citations should not include the following information: Citation Number, LSE, Date Notified, Date Issued, LSE CPUC ID, LSE Type, Specified Violation, Citation Amount, Pay Status, Appeal Status, Appeal Number? If yes, please explain.

The Commission should not publicize any information that could reveal an LSE's open position. Information identifying an individual LSE's needs could create opportunities for sellers to exercise market power and ultimately exacerbate affordability challenges. This is especially the case when: (1) procurement requirements can only be met by a limited set of suppliers, as with the attribute-specific components of the MTR Order; and (2) when procurement obligations are cumulative across multiple compliance years and publicized citations may influence the market for future compliance years.

The Commission should therefore publicly report only aggregate information regarding compliance with procurement orders, avoiding disclosure of the net position of any individual entity until the entirety of the procurement order is complete. This is consistent with the reporting that the Commission has provided in progress reports on MTR procurement progress.[7]

6.2 Should citations be issued annually? Why or why not?

The issuance of citations should align with compliance periods and, as discussed above in response to question 1.4, be: (1) based on the final verified deficiency for each compliance period; and (2) preceded by a good faith efforts process for each compliance period. There should be a clear process and transparent timeline for each stage of compliance enforcement, including good faith effort demonstration, Commission review, issuance of citations, and any subsequent penalty determination. In addition, a meet-and-confer should take place between the Commission and the LSE prior to issuance of citations so LSEs can explain the situation and demonstrate "good faith efforts" to prevent time consuming appeal processes.

[7] *See* https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-powerprocurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irpprocurement-track.

6.3 What timeframe should be implemented for issuance of procurement citations?

See response to question 6.2 above.

Section 7. Aligning Integrated Resource Planning (IRP), Resource Adequacy (RA), and Renewables Procurement Section (RPS)

7.1 Given that IRP, RA, and RPS have different goals and mandates, are there opportunities to align the three programs? Please explain.

The RA, IRP, and RPS programs are administered through separate rulemakings with different schedules and procurement objectives, resulting in overlapping and sometimes inconsistent requirements. As a result, LSEs may be required to procure resources that satisfy one program but not another, leading to duplicative procurement, increased costs, and over-procurement. Under challenging market conditions, in which new capacity is difficult to develop quickly and existing capacity is constrained, this may result in some LSEs facing double penalties for the same deficiency (e.g., an LSE plans to count a new resource for IRP and RA compliance obligations, and the resource is delayed). The Commission should therefore seek to align IRP procurement requirements with downstream RA and RPS requirements. In R.20-05-003, CalCCA proposed a mechanism for achieving this alignment through the implementation of the Reliable and Clean Power Procurement Program (RCPPP).[8] Elements of this proposal include a multi-year RA requirement aligned with the SOD program and a Clean Energy Standard that builds upon the existing RPS program to include zero-emissions resources and advance clean energy targets through 2045.

LSEs are also often required to report the same information multiple times in different forums and formats. Most notably, the Commission requests redundant contract information across IRP and RPS filings. In their bi-annual MTR filings, their RPS Procurement Plan filing , their RPS compliance filing (which asks about permitting information for developing projects), and the RPS Power Charge Indifference Adjustment (PCIA) Data Requests (which includes information for the Padilla Report), and monthly procurement status reports . LSEs are essentially reporting on their developing projects, in some form, 18 times per year in total. To limit the administrative effort associated with compliance reporting, the Commission should consider ways to combine compliance filings and provide Commission staff with technology solutions that allow them to access information for online resources (*e.g.*, resource IDs, nameplate capacity, technology type, capacity area, location, and contract term).

7.2 What burdens need to be overcome to align IRP, RA, and RPS?

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8 *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (July 15, 2025), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M573/K513/573513376.PDF.

CalCCA has no comments at this time.

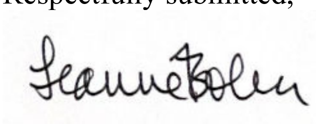
7.3 Are their stakeholder time constraints inherent in an effort to align IRP, RA, and RPS? Please explain.

The issues raised in response to question 7.1 are critically important to resolve. The Commission should prioritize the development of RCPPP so that parties have clarity on how to move forward with procurement to meet compliance obligations associated with reliability and clean energy goals.

III. CONCLUSION

CalCCA respectfully submits these informal responses and requests consideration of the recommendations herein.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

(Submitted to IRPDataRequest@cpuc.ca.gov.)

**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
WORKSHOP REPLY COMMENTS**

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July 16, 2026

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends that the Commission:

- Adopt the recommendations of CalCCA, Cal Advocates, WestLight Energy, and CLECA—and reject any resistance by the Joint IOUs—to include the consideration of structural reforms to the indifference framework within the scope of Track 3;
- In any expedited initial phase of Track 3, limit consideration regarding the RPS MPB to only potential reform mirroring the Track 1 RA MPB reforms and can be evaluated through an Energy Division Staff Report, and defer consideration of all other RPS MPB proposals—including a cap and/or inclusion of long-term contracts—until after sufficient process and record development; and
- Reject the Joint IOUs' proposed phasing of Track 3 given its deferred consideration of re-vintaging, delay of data access, and unworkable timetable.

[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 Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
WORKSHOP REPLY COMMENTS**

California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to the *Administrative Law Judge's Ruling Authorizing Party Comments on Track Three Workshop and Related Issues*[3] (Ruling)*,* dated June 19, 2026.

I. INTRODUCTION

Party Opening Comments demonstrate broad consensus that improvements to the Power Charge Indifference Adjustment (PCIA) and/or structural changes to the overall framework are necessary to ensure statutory indifference. CalCCA's Opening Comments encourage the Commission to: (1) adopt a broad scope to consider restructuring the indifference framework, including potentially through the adoption of an allocation framework; (2) prioritize Renewables Portfolio Standard (RPS) market-price benchmark (MPB) reforms, potentially mirroring the Track 1 Resource Adequacy (RA) MPB reform, formalize a re-vintaging framework, and establish a data access protocol for an immediate phase of Track 3; and (3) build into the schedule adequate time to allow parties to evaluate data and develop proposals.

In response to Opening Comments, CalCCA further recommends the Commission:

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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 Authorizing Party Comments on Track Three Workshop and Related Issues*, Rulemaking (R.) 25-02-005 (June 19, 2026).

- Adopt the recommendations of CalCCA, the Public Advocates Office at the Public Utilities Commission (Cal Advocates), WestLight Energy (WestLight), and the California Large Energy Consumers Association (CLECA)—and reject any resistance by the joint investor-owned utilities (Joint IOUs)—to include the consideration of structural reforms to the indifference framework within the scope of Track 3;
- In any expedited initial phase of Track 3, limit consideration regarding the RPS MPB to only potential reform mirroring the Track 1 RA MPB reforms and can be evaluated through an Energy Division Staff Report, and defer consideration of all other RPS MPB proposals—including a cap and/or inclusion of long-term contracts—until after sufficient process and record development; and
- Reject the Joint IOUs' proposed phasing of Track 3 given its deferred consideration of re-vintaging, delay of data access, and unworkable timetable.

II. THE TIME IS RIPE TO CONSIDER STRUCTURAL REFORMS TO THE INDIFFERENCE FRAMEWORK AS RECOMMENDED BY CALCCA, CAL ADVOCATES, WESTLIGHT, AND CLECA—BUT RESISTED BY THE JOINT IOUS

The time is ripe to consider structural reforms to the indifference framework, including allocation, as discussed on Day One of the Workshops and supported in Opening Comments by CalCCA, Cal Advocates, WestLight, and CLECA. The Joint IOUs urge caution in addressing these issues, raising: (1) the lack of criteria of which "legacy resources" to consider; (2) the definition of "uneconomic" in relation to these legacy resources; (3) the potential for introducing "unnecessary complexity" into the proceeding; (4) that such consideration will "significantly" extend Track 3; (5) that the 2017 case already examined mandatory allocations as then proposed by the Joint IOUs and that no material changes have occurred necessitating their reconsideration; and (6) that such consideration will distract from the Joint IOUs' highest priority issues of PCIA MPB reform.[4]

As highlighted by CalCCA, Cal Advocates, WestLight, and CLECA, both structural changes and the consideration of allocation to accomplish statutory indifference are ripe for consideration. This is especially the case given the substantial material changes since the 2017 case, including but not limited to the increase of customers departing bundled service for CCAs, increasing electricity rates and the affordability crisis, and the impact of increased load in California. As noted by CLECA:

[4] Joint IOU Opening Comments, at 3-6.

> Track 3 should include a genuine evaluation of structural alternatives to the current PCIA framework, not merely refinements to market price benchmarks. Commissioner Baker's Day 1 question about whether the current PCIA framework remains the right approach in light of forecast growth is a consequential issue that should be reflected in the Track 3 Scoping Memo.[5]

In addition, WestLight states that "[t]he proceeding should be scoped broadly to consider the wholesale structural reform of the indifference framework as discussed at the workshop, because the existing [PCIA] framework is not achieving indifference."[6]

Cal Advocates comprehensively discusses allocation as a potential component of a new framework, highlighting how it has the potential to mitigate rate volatility, render MPB refinement needs moot for PCIA ratemaking purposes, minimize the ongoing data access needs, and align load-serving entity incentives.[7] CLECA also recommends that the Commission consider whether allocation "for one or more attribute categories would preserve symmetric indifference while reducing the volatility associated with benchmark-based valuation."[8]

The PCIA framework refined in R.17-06-026 has yet to result in a ratemaking process in which one party or another has not bemoaned its significant shortcomings. Contrary to the Joint IOUs' assertions that no "material changes" have occurred since the 2017 case and therefore the Commission need not reconsider its prior rejection of allocation, major changes have occurred, including increasing departures from IOU bundled service and escalating load. The framework has also proven itself inflexible in responding to regulatory changes to the state's RA and Greenhouse-Gas programs, and unable to cope with significant changes in the energy, capacity and renewables markets. These shortcomings necessitate a close look at whether the existing PCIA framework is adequately ensuring indifference, or whether an alternative structure, including allocation and/or other mechanisms, should be adopted.

III. CONSIDERATION OF INITIAL RPS MPB REFORM AS PROPOSED BY THE JOINT IOUS SHOULD BE LIMITED TO POTENTIALLY MIRRORING THE TRACK 1 RA MPB METHODOLOGY GIVEN THE SUBSTANTIAL RECORD NEEDED TO CONSIDER OTHER MPB REFORMS

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5 CLECA Opening Comments, at 3.
6 WestLight Energy Opening Comments, at 2.
7 Cal Advocates Opening Comments, at 2-6.
8 CLECA Opening Comments, at 4.

The Joint IOUs recommend immediately considering "interim" RPS MPB reform, potentially in the form of applying the Track 1 RA MPB reforms to the RPS MPB, and establishing a cap.[9] While CalCCA supports the Commission considering RPS MPB reforms early in Track 3, this consideration should be limited to the Joint IOUs' request to potentially apply the Track 1 RA MPB reform. With an Energy Division Staff Report similar to, but more robust than, that provided in Track 1, the Commission can consider whether such a modification can quickly provide relief from PCIA volatility and/or inaccuracies.[10] Considerations of a cap, or incorporating long-term contracts into the RPS MPB, will require substantially greater record development and if considered, should only be in a later phase of Track 3. However, as the Commission knows well from the PCIA Undercollection Balancing Account (PUBA), caps have only led to more volatility over time. And while incorporating long-term contracts into the RPS MPB should be included in scope for consideration later in Track 3, the Commission has acknowledged it will take substantial record development to address concerns regarding the accuracy of the resulting RPS MPB.[11]

IV. THE JOINT IOUS' PROPOSED TRACK 3 PHASING SHOULD BE REJECTED FOR DEFERRING CONSIDERATION OF RE-VINTAGING, DELAYING DATA ACCESS, AND ESTABLISHING UNWORKABLE TIMELINES

The Joint IOUs' proposed Track 3 phasing should be rejected for deferring consideration of re-vintaging, delaying data access, and establishing unworkable timelines. As noted above, the Joint IOUs propose that an immediate Track 3A be initiated, considering only RPS MPB and Energy Index MPB reform. Instead, and as proposed by CalCCA in its Opening Comments and set forth in Table 1 below, Track 3 should begin with resolution of data needs for all of Track 3 to allow timely proposal development and issues ripe for Commission consideration, including limited RPS MPB reform and re-vintaging. In addition, the Joint IOUs' proposed timing of Track 3B (considering overall PCIA and indifference framework reform) is unworkable given it would provide only three months between a Joint Case Management Statement on Track 3B data access, the beginning of such data access for Track 3B, and the completion of Track 3B.

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9 Joint IOU Opening Comments, at 7.

10 A key shortcoming of the Phase I process and evidentiary record was the inability for parties to access the data underlying the report and to ask Staff questions about the report in a workshop or other format.

11 *See* Decision 23-06-006, *Decision Addressing Greenhouse Gas-Free Resources, Long-Term Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access,* R.17-06-026 (June 13, 2023) (declining after a Staff Proposal and substantial party comments to include long-term fixed price contracts in the RPS MPB based on concerns that the accuracy of the RPS MPB could be reduced, and stating it may reconsider this issue when RA market reforms are complete).

A. The Joint IOUs Fail to Justify Delaying Consideration of Re-Vintaging Guidelines When the Issues Can be Resolved Early in Track 3

While the Joint IOUs categorize re-vintaging as a "high priority" issue in their Opening Comments, they recommend delaying consideration of this issue until late 2027, with a decision in 2028. This is so the Commission can consider what the IOUs deem to be "more urgent" and less record intensive – RPS and Energy Index MPB reform.[12] Instead, re-vintaging should also be immediately addressed given the issue has been extensively addressed in other proceedings and limited record building would be necessary.

Two re-vintaging issues are consistently raised in General Rate Cases and other cases. *First*, the UOG re-vintaging framework has been teed up in several proceedings to be addressed in this statewide PCIA proceeding.[13] CalCCA has proposed a framework in the IOUs' General Rate Cases to efficiently and effectively address costs responsibility questions for existing and new investments in UOG, including requiring the IOUs to define the end of life for UOG assets to appropriately limit cost recovery from each asset's original vintage assignment. The Commission, however, has consistently stated that it will consider the re-vintaging framework in a statewide rulemaking.[14] PG&E has also requested that the schedule in its Helms Uprate Application be suspended until the Commission decides on any modifications to vintaging in this proceeding.[15] While the Commission has not ruled on PG&E's motion, PG&E has otherwise been granted authority to move forward with the Helms Uprate, and a decision on cost allocation issues should not be delayed. The vintaging issues are ripe for consideration here and can be addressed through limited record building.

Second, the Commission should establish a forum for adequate discovery and comments on PCIA-eligible contract amendments, renewals, or extensions. Currently, such extensions are generally considered through an advice letter process which does not provide adequate time or process for discovery and comments on such contract extensions.[16]

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12 Joint IOU Opening Comments, at 6-8.

13 *See* CalCCA Opening Comments, at 7-8.

14 *See* CalCCA Opening Comments at 7-8; *see also California Community Choice Association's Reply Comments on the Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes*, R.25-02-005 (Apr. 2, 2025) (CalCCA OIR Reply), at 33-34 (summarizing Commission consideration of vintaging questions).

15 *See Joint Motion of Pacific Gas and Electric Company (U 39 E) and Californians for Green Nuclear Power to Hold Phase II in Abeyance Pending Resolution of Issues in Rulemaking 25-02-005,* Application 23-12-014 (Jan. 16, 2026).

16 *See* CalCCA OIR Reply, at 35-37 (discussing the contract re-vintaging issues).

B. The Joint IOUs’ Proposed Phasing of Data Access Should be Rejected Because it Impedes Timely Proposal Development and is Unworkable

The Joint IOUs propose that data access be “bifurcated” according to their proposed Track 3A/Track 3B phasing, which includes the dates proposed in the Joint IOUs’ Opening Comments.[17] Therefore, data access for the Joint IOUs’ proposed Track 3A issue would be addressed first and would be limited to data needed to analyze RPS MPB and Energy Index MPB issues. Upon completion of Track 3A in February 2027, the Joint IOUs propose a 120-day Track 3B meet and confer process to decide on data access for PCIA MPB or alternative indifference frameworks.[18] This would result in data access for Track 3B beginning at the earliest in June 2027, with a Proposed Decision to be issued in September 2027.[19] Not only is three months an unworkable amount of time for the extensive issues proposed to be addressed in Track 3B, there is no reason to delay data access for CalCCA to begin analyzing and creating proposals. Indeed, the Joint IOUs have the data today and are able to formulate proposals. Delaying and restricting the amount of time available for parties in this proceeding to analyze the important issues under consideration is not only unfair, but unnecessary. Therefore, the Commission should instead adopt CalCCA’s proposal to allow access to the full suite of data at the beginning of Track 3, as set forth below in Table 1, below.

Table 1: CalCCA Proposed Timetable

Track 3 Scoping Memo	August 2026
Track 3A: **Data Access (for Tracks 3A and 3B)** **RPS MPB Reform** **Re-vintaging Standards**	
Joint CMS (after data Meet & Confer)	(within 60 days) October 2026
Data Production	By November 2026
Proposed Decision	January 2027
Final Decision	March 2027
Track 3B – Concurrent Tracks (beginning April 2027)	
Track 3B.1	**Track 3B.2**
Indifference Structure Reform Proposals Party proposals by May 2027	Existing PCIA Reform Party proposals by May 2027

17 *See* Joint IOU Opening Comments, at 12-13.
18 Joint IOU Opening Comments, at 13.
19 Joint IOU Opening Comments, at 13.

V. CONCLUSION

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

Respectfully submitted,

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

July 16, 2026

Case No.

IN THE COURT OF APPEAL OF THE STATE OF CALIFORNIA
THIRD APPELLATE DISTRICT

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Petitioner,

v.

CALIFORNIA PUBLIC UTILITIES COMMISSION

Respondent,

PACIFIC GAS AND ELECTRIC COMPANY

Real Party in Interest.

From Decision No. 25-12-027 (December 23, 2025) of the
California Public Utilities Commission

PETITION FOR WRIT OF REVIEW; MEMORANDUM OF POINTS AND AUTHORITIES
[APPENDIX OF EXHIBITS FILED CONCURRENTLY]

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CERTIFICATE OF INTERESTED ENTITIES OR PERSONS

Pursuant to California Rules of Court, rule 8.724(c) and rule 8.208, Petitioner California Community Choice Association ("CalCCA") hereby certifies that CalCCA is a California non-profit corporation, and no entity or person has an ownership interest in CalCCA. Petitioner knows of no other entity, as that term is defined in rule 8.208(c)(2), or person, other than the parties themselves, with a financial or other interest in the outcome of this proceeding that must be disclosed.

DATED: July 17, 2026

SHUTE, MIHALY &
WEINBERGER LLP

By: Aaron Stanton

AARON M. STANTON
SHANTHI M. CHACKALACKAL

Attorneys for California
Community Choice Association

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INTRODUCTION

Community choice aggregators ("CCAs") are local government agencies that compete with investor-owned utilities to procure electricity on behalf of customers. Recognizing that customers would move between utilities and CCAs for electricity generation service, the Legislature charged Respondent California Public Utilities Commission with preventing cost shifts between CCA and utility customers. This statutory "indifference" mandate—so called because customers' electricity rates must be "indifferent" to other customers' choices to purchase electricity from a CCA or utility—prohibits either group from subsidizing the other.

The Commission implements the indifference mandate by annually calculating an "indifference adjustment" that is applied to customers' bills. The indifference adjustment ensures CCA customers pay for the share of generation resources the utility procured for them prior to their departure for CCA service, so that utility customers do not shoulder additional costs. It also ensures CCA customers receive a share of the same resources' benefits, so that utility customers do not receive windfalls. In this Petition, California Community Choice Association ("CalCCA"), a non-profit representing 24 CCAs, challenges two errors in Commission Decision 25-12-027, Decision Approving Pacific Gas and Electric Company's 2026 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2026 Electric Sales Forecast (Dec. 23, 2025) ("Decision"), which approved this year's indifference adjustment for Pacific Gas and Electric Company ("PG&E").

First, the Decision unlawfully requires certain CCA customers to subsidize PG&E customers' compliance with renewable energy requirements. These CCA customers paid for a portion of the Renewable Energy Credits ("RECs")—tradable credits used to satisfy renewable electricity obligations—that PG&E generated and "banked" for future use prior to 2019. At that time, these CCA customers were still utility customers; they later departed for CCA service. When PG&E uses banked RECs to satisfy its customers' renewable obligations today, PG&E's current customers realize nearly the entire value of the RECs, despite paying for only a portion of their costs. But later-departed CCA customers who paid for a share of the RECs receive no value today. The RECs do not satisfy or reduce their renewable obligations. Instead, the payments the CCA customers made for the RECs subsidize PG&E customers' compliance.

The indifference statutes require the Commission to fix this cost shift through the indifference adjustment. The Commission did not do so.

Indeed, the Commission declined even to evaluate whether PG&E's proposal ensured indifference. Without explanation, the Decision found PG&E's approach "reasonable" as an interim solution and punted an evaluation of indifference to a subsequent proceeding. But the Decision is not an interim solution. While the Commission adopts a structure to facilitate correcting errors as to banked RECs used in 2026, it strands banked RECs used in 2025. For those RECs, the Decision's cost shift is permanent.

In enacting a cost shift, the Commission has exceeded the scope of its authority and failed to proceed in the manner required by law. Moreover, because the Decision does not evaluate whether PG&E's proposal ensures indifference despite the Commission's statutory obligation to prevent cost shifts, (1) the Decision does not contain the required finding that the approved rates ensure indifference, and (2) the Commission failed to review all of the relevant factors, constituting an abuse of discretion. The Decision must be reversed.

The Decision's second error involves the Commission's haste to implement a separate change to the indifference adjustment. Last year, the Commission issued a decision changing the methodology for calculating a specific component of the indifference adjustment called the Resource Adequacy Market Price Benchmark ("RA Benchmark"). Despite a statutory prohibition on retroactive ratemaking, and absent any factual finding of an actual cost shift in 2025 under the old methodology, the prior decision directed the utilities to apply the new methodology retroactively to rates already being collected in 2025. The Commission claimed the indifference statutes required such immediate action. CalCCA challenged the prior decision in a separate writ petition on the grounds that it violated the statutory rule against retroactive ratemaking and was not supported by the findings. (*Cal. Community Choice Assn. v. P.U.C.*, Case No. C105174.) This Court denied CalCCA's petition on June 25, 2026, and CalCCA petitioned the Supreme Court for review. (*Cal. Community Choice Assn. v. P.U.C.*, Case No. S297373.) The Supreme Court has not yet acted on the petition.

The current Decision approves PG&E's implementation of the prior decision. That is, the Decision approves rates PG&E determined using the new methodology for calculating the RA Benchmark. Because the prior decision violated the rule against retroactive ratemaking and was not supported by the findings, it is invalid.[1] A decision that implements an invalid act is itself invalid. This Decision must be reversed.

Taken together, the Decision's errors reveal a double standard. When CalCCA shows that a PG&E proposal would shift costs to CCA customers, the Commission approves it and defers evaluating indifference. Conversely, in the name of ensuring indifference, the Commission implements a change to the indifference adjustment retroactively, benefitting utility customers, notwithstanding a statutory prohibition on retroactive ratemaking and without finding an actual cost shift. In short, when the CCAs show a cost shift, the Commission delays; when

[1] This Petition does not seek review of the prior decision and does not ask this Court to adjudicate the prior decision's invalidity. However, because the error in the current Decision depends on the invalidity of the prior decision, CalCCA anticipates requesting that this Court sequence its decision on section II of the Argument in this Petition to follow resolution of CalCCA's prior petition in Case No. S297373.

the utilities do, the Commission acts with too much haste. Both errors independently require correction. Taken together, the one-sidedness of the Commission's actions offends the Commission's statutory responsibility to treat both utility and CCA customers fairly.

The Commission made the same errors in decisions affecting the other two major utilities, Southern California Edison Company ("SCE") and San Diego Gas & Electric Company ("SDG&E").[2] Across all three utilities, the Commission's errors will shift billions of dollars of costs from utility customers to CCA customers. Average CCA customers in some disadvantaged communities were expected to see their indifference adjustment rates increase by over $500 this year alone. CCAs will struggle to protect their customers from such significant rate shock, and these higher costs will undermine CCAs' competitiveness. The

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[2] CalCCA is concurrently filing a Petition for Review of D.25-12-028 (affecting SCE) in this Court. CalCCA anticipates filing a motion to consolidate the two petitions. Additionally, two individual CCAs are concurrently filing a Petition for Review of D.25-12-008 (affecting SDG&E) in the Fourth Appellate District, where they will likely request to transfer the writ petition to this Court. If the Supreme Court transfers the petition, CalCCA will request consolidation of all three petitions.

indifference statutes and the rule against retroactive ratemaking require a different result.

In light of the Decision's errors, CalCCA respectfully requests that the Court grant the Petition for Review, reverse the Decision, and grant the relief requested below.

PETITION FOR WRIT OF REVIEW

I. Jurisdiction

1. The Commission issued the Decision on December 23, 2025. (11:72:APP2534.)[3] CalCCA timely applied for rehearing on January 12, 2026. (11:74:APP2623; Pub. Util. Code § 1731(b)(1).)[4] As of this filing, the Commission has not acted on the application. CalCCA thus may treat the application as denied. (§ 1733.) Parties need not file petitions within 30 days of constructive denial. (*Sokol v. P.U.C.* (1966) 65 Cal.2d 247, 252.) The Petition is timely, and the Court has jurisdiction under section 1756(a).

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[3] Citations to the Appendix of Exhibits are in the form [Volume]:[Tab]:[Page Number]. Tabs may be located using the PDF files' bookmarks feature.

[4] Unless otherwise noted, all statutory references are to the Public Utilities Code.

II. Parties

2. CalCCA is a California nonprofit mutual benefit corporation that represents the interests of CCAs formed and operated by local governments. CalCCA was an active party in proceeding A.25-05-011, filed a protest objecting to PG&E's application (2:05:APP0224), and served written comments on the Decision (11:66:APP2474; Cal. Code Regs., tit. 20, § 14.3). CalCCA applied for rehearing of the Decision on January 12, 2026. (11:74:APP2623; § 1731; Cal. Code Regs., tit. 20, § 16.1.)

3. Respondent California Public Utilities Commission is a state agency of constitutional origin charged with regulating public utilities under the Public Utilities Code and article XII of the California Constitution.

4. Real party in interest PG&E is a corporation formed and existing under the laws of the State of California, an investor-owned electric utility, an "electrical corporation" under section 218, and a "public utility" under section 216.

III. Standing

5. CalCCA's mission is to foster a legislative and regulatory environment that supports the development and long-

term sustainability of the provision of electric service by local governments through CCAs.

6. The Decision undermines this mission by violating statutory mandates requiring that CCA customers receive value for benefits they have paid for and by implementing unlawful retroactive ratemaking. If not reversed, the Decision will destabilize the regulatory environment in which CCAs operate and undermine the long-term financial sustainability of CCA service.

7. This Petition presents claims challenging the Decision's lawfulness and the adequacy of its findings, questions of law that affect all of CalCCA's member CCAs and that do not require individualized proof from any particular member. The requested relief—that the Court set aside the Decision and direct the Commission to cure its defects—would redress injuries to all CalCCA members in PG&E's service territory uniformly.

8. CalCCA represents its member CCAs before the Commission in proceedings related to indifference adjustment rates, including the proceeding underlying the Decision, to ensure the legality and reasonableness of indifference adjustment methodologies and the accuracy of implemented rates.

9. The Decision's changed method for valuing Renewable Energy Credits and retroactive implementation of the new methodology described in Commission Decision D.25-06-049, Decision Adopting Changes to the Calculation of the Resource Adequacy Market Price Benchmark (June 27, 2025) (the "RA Decision") have upset CCA members' planning and budgeting. CCAs relied on PG&E's prior method for valuing Renewable Energy Credits banked before 2019. CCAs also planned their operations, rates, and budgets in reliance on the methodology for calculating the RA Benchmark, a component of the indifference adjustment rate, that had been in place for six years prior to the RA Decision.

10. The legal errors made by the Decision also substantially increase indifference adjustment rates that form a significant component of CCA customers' electricity bills. As a core part of serving customers, CalCCA's members work to ensure the accuracy of indifference adjustment rates, plan for changes to the indifference adjustment, and protect their customers from rate shock resulting from such changes. To protect customers from the severe rate shock caused by this Decision, CCAs have had to divert resources from other priorities.

11. An order setting aside the Decision and directing the Commission to cure its legal errors will decrease CCA customers' rates, prevent rate shock, and restore stability and predictability to CCA budgeting and planning.

IV. Venue

12. Sacramento County houses CalCCA's principal place of business. Venue is proper in the Third Appellate District. (§ 1756(d).)

V. Exhibits

13. All exhibits in the appendix accompanying this Petition are true copies of original documents filed with the Commission in proceeding A.25-05-011. The exhibits are incorporated by reference as though fully set forth in this Petition. The appendix is paginated consecutively.

VI. Statement of the Case

A. Background: CCAs and the Indifference Adjustment

1. In 2002, to foster competition, the Legislature enabled Community Choice Aggregators to empower communities to purchase clean electricity.

14. Historically, California's investor-owned utilities, including PG&E, had a monopoly over the sale, transmission, and

distribution of electricity in their service territories. In the 1990s, however, the Legislature deregulated sales of electric generation to consumers, finding that a competitive system in which customers could choose their electric power suppliers would best serve the public. (§ 330(d).)

15. In 2002, the Legislature authorized local governments to form CCAs in the investor-owned utilities' territories. (Stats. 2002, ch. 838 (AB 117), §§ 2, 3.) CCAs are local government organizations that purchase electricity and supply it to customers in their communities.[5] (§ 331.1.) As additional players in the energy market, CCAs promote competition among energy suppliers, enabling lower rates. (*See* § 330.)

16. CCAs also offer an alternative to profit-driven utilities, allowing customers to choose electricity generation aligned with community values and priorities. (*See* Stats. 2011, ch. 599 (SB 790), § 2.) Thus, as many communities have sought to

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[5] The utilities maintained their monopoly over electricity transmission and distribution and continue to deliver electricity and bills to CCA customers. As a result, CCA customers are customers of both a CCA and a utility. For simplicity, however, this Petition refers to them as solely "CCA customers." Customers for whom a utility procures electricity are "utility customers" or "PG&E customers."

combat climate change or increase affordability, CCAs have pursued clean energy and lower rates. (*Id.*)

17. Today, 25 CCAs serve more than 15 million California customers across more than 200 cities and counties.

2. To promote equity, the Legislature directed the Commission to ensure CCA customers and utility customers are "indifferent" to customers joining CCAs.

18. In creating CCAs, the Legislature recognized that utilities had entered long-term contracts for energy supplies intended to serve their customers—including customers who would later depart for CCAs. (*See* § 366.2(f).) But the CCA customers' departure would leave fewer utility customers on the hook for the above-market costs of the utility's generation portfolio. As a result, if the utility could not sell excess supplies at or above its costs, CCA customers' departure could increase remaining utility customers' rates.

19. To prevent this, the Legislature required the Commission to ensure that CCA customers' departures would not shift costs between CCA customers and utility customers. (§§ 366.2(a)(4), 366.3; *see also* §§ 365.2, 366.2(d)(1).) This requirement is called ratepayer "indifference," because

customers' rates must be indifferent to—i.e., unchanged by—customers' departures for CCAs.

20. To prevent cost shifts, the Legislature allowed utilities to recover certain costs from CCA customers. Those costs include the share of the unavoidable above-market costs of long-term electricity contracts attributable to CCA customers. (§ 366.2(f)(2).)

21. Recognizing that equity required fair treatment of both utility and CCA customers, the Legislature made ratepayer indifference a two-way street. It required not only that utility customers "shall not experience any cost increase as a result of" CCA customers' departure, but also that *CCA customers* do "not experience any cost increases as a result of … costs that were not incurred on [their] behalf." (§ 366.3.)

22. Similarly, in determining rates, the Commission not only requires CCA customers to pay costs incurred on their behalf; the Commission also must *reduce* CCA customers' rates by "the value of any benefits that remain with" utility customers. (§ 366.2(g).) In other words, if CCA customers pay for a portion of a utility's generation resources, they must receive credit for a share of those resources' benefits.

23. Electricity prices fluctuate over time. Thus, a long-term contract at a fixed price could be a great deal if electricity prices increase, resulting in significant savings compared to short-term purchases at market prices. In contrast, if electricity prices decrease, a long-term contract could become an albatross. For contracts that utilities executed when CCA customers were still utility customers, indifference requires that CCA customers share in both the burdens of the bad deals *and* the benefits of the good ones.

3. The Commission created and revised a complex method for determining the rates needed to ensure indifference.

24. In 2002, the Commission established the Energy Resource Recovery Account ("ERRA") process, which set up utility balancing accounts for various procurement costs and collections from ratepayers. (D.02-10-062, Interim Opinion (Oct. 25, 2002) at p. 61.)[6]

25. Every year, each utility files an ERRA forecast application based on projected electricity demand for the

[6] Commission decisions are available at https://docs.cpuc.ca.gov/DecisionsSearchForm.aspx.

following year. (D.19-10-001, Decision Refining the Method to Develop and True Up Market Price Benchmarks (Oct. 17, 2019) at p. 3.) In approving ERRA forecast applications, the Commission approves (1) a revenue requirement to cover anticipated power procurement costs, (2) a sales forecast, and (3) the resulting rate. (*Id.*)

26. At the same time, the Commission also looks back at the prior year. The prior forecast is "trued up" to reflect actual procurement costs and sales. Any over- or under-collection is credited or debited on the relevant utility's revenue requirement for the next year. (D.18-10-019, Decision Modifying the Power Charge Indifference Adjustment Methodology (Oct. 19, 2018) at p. 141.)

27. As part of the ERRA process, the Commission also determines the rate changes needed to ensure indifference between CCA and utility customers. (7:34-01:APP16564-66.) These changes are known as the Power Charge Indifference Adjustment ("PCIA," or "indifference adjustment").

28. The indifference adjustment compares the utilities' generation procurement costs with the market value of the utilities' portfolio of generation assets. (*Id.*) The difference

between portfolio value and cost—positive or negative—is recovered through the indifference adjustment rate. (*Id.*) If procurement costs exceed portfolio value, both utility and CCA customers share responsibility for above-market costs incurred on their behalf. In contrast, if portfolio value exceeds procurement costs, both utility and CCA customers get the benefit of the below-market cost of the generation portfolio. (D.18-10-019, at p. 88.)

29. This methodology is applied each year in ERRA Forecast proceedings. The Commission forecasts the utility's anticipated power procurement costs and portfolio value and determines what rate changes will ensure indifference in the coming year. (7:34-01:APP1665-67.)

30. Each year, as with ERRA rates, the prior year's indifference adjustment is also trued up. (7:34-01:APP1668.) The annual indifference adjustment thus includes both prospective charges and a true-up between forecasted and actual charges for the prior year.

31. The indifference adjustment amount is recovered from both utility customers and CCA customers. (*See* 9:44:APP2001; 11:74:APP2654-56.) However, utility customers

and CCA customers experience the indifference adjustment differently.

32. For utility customers, the indifference adjustment is part of total generation rates. The utility generation portfolio has a fixed total cost. The "at market" portion of that total is paid by utility customers only. But any "above market" portion is paid by both utility and CCA customers through the indifference adjustment. (11:74:APP2656; 9:44:APP2001-02.) Consequently, when current market prices increase, the "at market" portion of the utility customers' costs increase, and their indifference rate decreases. When current market prices decrease, the "at market" portion decreases, and the "above market" indifference portion increases. (*Id.*) Thus, for utility customers, the indifference adjustment acts like a water balloon being squeezed: any change in indifference rates is balanced by an opposite change in generation rates.

33. Because utility customers do not share in CCAs' above-market costs, there is no similar water balloon effect for CCA customers. An increase in the indifference adjustment does not decrease CCAs' generation rates, even if a CCA's portfolio is above-market. Yet to remain competitive with utilities that

incurred above-market costs, a CCA facing high indifference adjustment rates would need to reduce its generation rate to a level *below cost.* CCAs often make such adjustments, including to shield their customers from "rate shock"—i.e., sudden significant increases in their electricity bills, including increases in their indifference rates. (2:05:APP0234-35.) These efforts require CCAs to divert resources from other priorities.

34. In designing the indifference adjustment, the Commission determined that the market value of the utilities' portfolios of generation assets would be established by setting proxies, called "market price benchmarks," for various components of the portfolios. (D.25-06-049, at p. 5.) Unlike fuel costs or energy procurement costs, the market value of a portfolio of assets cannot be determined by simply looking at a ledger. Instead, the market price benchmarks—calculated using weighted averages of certain sets of market transactions—are intended to approximate current market value. (7:34-01:APP1666-67.) As part of the indifference adjustment, market price benchmarks are forecast each year during the ERRA process and "trued-up" the following year. (*Id.* at APP1665-68.)

35. The market price benchmarks used in calculating indifference include benchmarks related to resources procured for Renewables Portfolio Standard ("RPS") and Resource Adequacy ("RA") purposes.[7]

36. To ensure ratepayer indifference, the indifference adjustment is calculated separately for multiple yearly "vintages." (7:34-01:APP1669-70.) When a customer departs utility service for a CCA, they must still share the burdens and benefits of resources procured by the utility to serve them prior to their departure. (*Id.*; § 366.2.) But that customer has no responsibility for resources procured *after* their departure, because the utility no longer needed to serve them. Thus, for all customers that departed for CCAs in the same year or "vintage," the indifference adjustment is calculated based on the resources procured or constructed as of that year. (7:34-01:APP1669-70.)

37. This Petition challenges two aspects of the Commission's PG&E 2026 ERRA Forecast Decision, one related

[7] The market price benchmarks also include the "Energy Index," which is not at issue here.

to credits used for RPS compliance, and one related to RA. The following paragraphs describe each in turn.

B. In assigning no value to CCA customers for Renewable Energy Credits generated and "banked" before 2019, the Commission required certain CCA customers to subsidize current utility customers' compliance with renewable energy requirements.

1. The Legislature required a transition to renewable electric generation and authorized Renewable Energy Credits, or "RECs," to facilitate compliance.

38. To encourage clean energy, the Legislature in 2002 established (and subsequently updated) the RPS. (Stats. 2002, ch. 516 (SB 1078); Stats. 2015, ch. 547 (SB 350); Stats. 2018, ch. 312 (SB 100).) RPS regulations require that a certain percentage of power supplied by an electric service provider comes from renewable sources. (§ 399.11.) RPS requirements apply to utilities and CCAs. (§§ 399.13(a), 399.15 [applying to retail sellers]; § 399.12(j) [retail sellers include CCAs].)

39. To facilitate RPS compliance, the Legislature created RECs. RECs are tradeable commodities representing the renewable attributes of one unit of electricity produced by a renewable source. (§ 399.12(h).)

40. Electrons of renewable energy are indistinguishable from other electrons and are generally consumed when generated. A REC, however, may be sold and used separately from its underlying renewable energy. Thus, RECs may be used for RPS compliance purposes immediately. They may be sold to another entity. Or they may be banked for future use. (*See* D.19-10-001, at pp. 10, 13.)

2. Utility and CCA customers share responsibility for RECs' costs.

41. All customers on whose behalf a renewable resource was procured are responsible for the costs of the RECs the resource generates. (7:34-01:APP1695, APP1705-08.)

42. This cost responsibility applies whether the customers are still utility customers or whether they departed for CCAs. CCA customers pay their share of RECs' costs through indifference adjustment rates. (*Id.*)

43. To illustrate, consider a windfarm procured in 2012. At that time, all utility customers paid for the windfarm in generation rates, as shown in Figure 1.

Figure 1. Cost Responsibility – RPS Resource

		Utility Customers
2012	Windfarm	
		Pay costs in generation rates

44. By 2015, the windfarm was producing energy and associated RECs. Utility customers continued to pay for these assets in generation rates. (*See* 3:28:APP0547-48.) By this time, some customers for whom the windfarm was procured had departed for CCAs. (*See* 3:28:APP0546.) These CCA customers paid for the share of the above-market costs of the RECs and energy attributable to them in indifference adjustment rates, as shown in Figure 2. (*See also* 7:34-01:APP1695.)

Figure 2. Cost Responsibility – RECs[8]

		Utility Customers	CCA Customers
2015	Energy / RECs		
		Pay at-market costs in generation rates & above-market costs in indifference rates	Pay above-market costs in indifference rates

[8] Figure 2 does not include the indifference adjustment's accounting for value, described below.

3. The Commission incorporated RECs' unique value into the indifference calculation.

45. Accounting for RECs' *value* has proved complicated.

46. Before 2011, the indifference adjustment valued renewable resources only for their energy and capacity. (D.11-12-018, Decision Adopting Direct Access Reforms (Dec. 7, 2011) at p. 9.)

47. In 2011, however, the Commission recognized that generation from RPS resources had compliance value, too. That is, in addition to powering a home or business, generation from RPS resources could also satisfy customers' RPS compliance obligations. The market recognized and assigned value to resources' eligibility for RPS compliance. (*Id.* at p. 17.)

48. To account for resources' value, the indifference statutes require that CCA customers' responsibility for resources' costs must be reduced by the *benefits* of those resources (1) that are attributable to CCA customers and (2) that remain with utility customers. (§ 366.2(g).) The benefits—here, of RPS-eligible resources—may be provided either in kind, through reduced RPS compliance obligations, or in value, through a credit to indifference adjustment rates. (*See* § 366.2(g).)

49. Thus, in D.11-12-018, the Commission modified the indifference adjustment to provide CCA customers credit in indifference adjustment rates for the compliance value of RPS resources in the utilities' portfolios. (D.11-12-018, at pp. 2-3, 17; *see also* § 366.2(g).)

50. To provide this credit, the Commission created a new RPS market price benchmark ("RPS Benchmark"). The RPS Benchmark reflects the "estimated incremental value of each unit of RPS-eligible energy that is attributable to the fact of that eligibility." (D.19-10-001, at p. 7.) Notably, the value signified by the RPS Benchmark—the compliance value of a unit of energy's renewable attributes—is similar to the value captured by a REC. (*See* § 399.12(h)(2) [RECs reflect energy's "renewable and environmental attributes"].)

4. The Commission recognized that RECs have value when used for compliance purposes.

51. In 2019, the Commission further revised its method for addressing RECs' value. The Commission recognized that RECs should be valued differently depending on whether they were (1) used for compliance immediately, (2) sold, or (3) banked for use or sale in the future. (D.19-10-001, at p. 10.)

52. Under D.19-10-001, when RECs are used for compliance purposes, they are valued in the indifference adjustment at the current RPS Benchmark, a proxy for market value. (*Id.* at pp. 13, 28.) The RPS Benchmark offsets the utility's portfolio cost in the indifference adjustment calculation (3:28:APP0548-50), decreasing CCA customers' indifference adjustment rates and increasing utility customers'. In this way, utility customers "pay" or "credit" CCA customers for a share of the benefits utility customers receive when RECs are used to reduce their compliance obligations. (3:28:APP0554-55; 7:34-16:APP1786.) CCA customers paid for these benefits by paying for a share of the RECs' costs. (7:34-01:APP1695, APP1705-08.)

53. *Sold* RECs are valued in the indifference adjustment at their actual sale price. (D.19-10-001, at pp. 13, 29.) The revenues from those sales also offset the utility's portfolio cost in the indifference adjustment.

54. Although valuing *banked* RECs proved controversial, the Commission ultimately decided to treat banked RECs as if they had *no* value in the current year. (*Id.* at p. 27) Instead, the RECs would be valued at the sale price or RPS Benchmark in the future when they were actually sold or used. (*Id.* at pp. 49, 53.) In

the future year, the RECs' value would offset portfolio costs, reducing CCA customers' indifference adjustment rates.

55. D.19-10-001 applied these new methodologies prospectively "to RECs generated commencing January 1, 2019 and going forward." (*Id.* at p. 47.) D.19-10-001 did not specifically address how RECs generated and banked *before* 2019 should be treated. This Petition concerns that unresolved question.

5. Between 2011 and 2019, the utilities banked many RECs. CCA customers who had already departed utility service received credit for their value.

56. Between 2011 and 2019, when a utility procured a REC, utility customers received direct value if it was used for compliance that year. (*See* 7:34-01:APP1713.) If the RECs were banked, utility customers received deferred value. (7:34-01:APP1705.)

57. After D.11-12-018, the indifference adjustment in the year the REC was generated also provided value to CCA customers who had *already departed* utility service. (3:28:APP0548.) These "Previously-Departed" CCA customers had paid for a share of the underlying renewable resources when they were utility customers and continued to pay for a share of

the RECs through indifference rates. (*See id.*; 7:34-01:APP1695, APP1708.) But because they had left utility service, they could not use the RECs for RPS compliance (7:34-01:APP1711.) Instead, to ensure indifference, the indifference adjustment provided them with credit, for the share of the RECs' value attributable to them, at that year's RPS Benchmark. (3:28:APP0548-50.) Previously-Departed customers received this credit regardless of whether the RECs were used for utility customer compliance immediately or banked for future use.

58. Returning to the hypothetical windfarm procured in 2012, Figure 3 depicts costs and benefits associated with RECs generated and used for utility customer compliance in 2015. Previously-Departed CCA customers paid for their share of the RECs' costs and received a credit for their share of the benefits through indifference adjustment rates. (*See* 7:34-01:APP1711.) Utility customers paid for the RECs' costs in generation rates and paid a credit to Previously-Departed CCA customers in indifference adjustment rates; they received the RECs' benefits in the form of reduced RPS compliance obligations. (7:34-01:APP1710-11.)

Figure 3: Costs and Benefits – RECs Used Immediately

2015 Energy / RECs	Utility Customers	Previously-Departed CCA Customers
	Pay at-market costs in generation rates & above-market costs in indifference rates	Pay above-market costs in indifference rates
	Receive reduced compliance obligations	Receive credit to indifference rate

59. From 2013 to 2018, the utilities generated more renewable energy than needed for RPS compliance. (7:34-01:APP1714.) They thus banked many RECs for the future.

60. Many RECs banked between 2013 and 2019 are still available to be used for utility customer compliance. (*Id.*)

6. Under the Decision, utility customers who paid for RECs banked before 2019 and who later departed for CCA service do not receive any value or benefit for their share of those banked RECs when they are used for utility customer compliance.

61. Between 2013 and 2019, as the utilities banked numerous RECs, many utility customers departed utilities for CCA service. (7:34-01:APP1707-09.) For example, 63% of PG&E customers in 2013 later departed for CCA service. (*Id.*; 8:43.1:APP1914.)

62. These "Later-Departed" customers—who as utility customers paid for a share of the RECs when they were

generated and banked before 2019, but who subsequently departed utility service—represent an indifference problem. Later-Departed customers, along with current utility customers, paid for pre-2019 banked RECs in two ways when the RECs were generated. They paid Previously-Departed CCA customers for their share of the benefits of pre-2019 Banked RECs through indifference adjustment rates at the RPS Benchmark. (Those Previously-Departed customers were therefore made whole and are not owed anything else.) They also paid for their own share of the RECs' costs through generation rates. (7:34-01:APP1705, APP1710-11.)

63. But when RECs banked before 2019 are used for compliance purposes today, *only current utility customers* realize the benefits. (7:34-01:APP1696; 7:34-16:APP1786.) Later-Departed customers—despite making the same payments as utility customers when the RECs were generated—do not realize any value. (*Id.*; 7:34-15:APP1784) The use of the RECs for current utility customer compliance does not in any way reduce the Later-Departed customers' compliance obligations. (7:34-01:APP1711; 7:34-15:APP1784.) And D.19-10-001 does not expressly direct that Later-Departed customers should receive

credit in the indifference adjustment when RECs generated and banked before 2019 are used for current utility customer compliance. (*See* 7:34-15:APP1784; 3:28:APP0551.)

64. Absent such a credit, Later-Departed customers get nothing for the share of the pre-2019 banked RECs they paid for. (*See* 7:34-01:APP1696.) Instead, Later-Departed customers' past payments for portions of the RECs are subsidizing current utility customer compliance. (*Id.*) Under these circumstances, the Commission has effectively shifted the cost of the RECs that utility customers use for compliance to Later-Departed customers.

65. Because Later-Departed customers make up a large percentage of the customers who paid for the pre-2019 banked RECs, their share of the costs of those RECs—and, correspondingly, the scale of the subsidy—is significant. (7:34-01:APP1709.) For example, Later-Departed customers paid 63% of the cost of RECs PG&E banked in 2013. (*Id.*) To prevent a subsidy, Later-Departed customers would need to receive a credit worth 63% of the RECs' benefits when the REC is used. (*Id.*)

66. Returning again to the hypothetical windfarm, Figure 4 shows a REC generated and banked in 2017 and used

for current utility customer compliance today. It shows that Later-Departed customers made the same payments as current utility customers in 2017, when they were *also* utility customers. Today, current utility customers realize the value of the RECs through reduced compliance obligations. Later-Departed customers do not realize any value.

Figure 4: REC Banked in 2017 and Used Today

	Current Utility Customers	Later-Departed CCA Customers	Previously-Departed CCA Customers
2017 Energy / RECs	Pay at-market costs in generation rates Pay above-market costs in indifference rates		Pay above-market costs in indifference rates Receive credit to indifference rate
Today Banked RECs	Receive reduced compliance obligation	*No credit; no reduced obligation*	

7. The Commission issued conflicting interim decisions concerning RECs banked before 2019.

67. The indifference statutes prohibit cost shifts between utility and CCA customers. (§§ 366.2(a)(4), 366.2(d)(1), 366.2(g), 366.3.) The CCAs, including through CalCCA, repeatedly brought the potential cost shift associated with pre-2019 banked RECs to the Commission's attention. (*See, e.g.*, D.23-06-006, Decision Addressing Greenhouse Gas-Free Resources, Long-term

Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access (June 13, 2023) at p. 44; D.24-08-004, Decision Denying Petition for Modification of Decision 23-06-006 (Aug. 2, 2024) at pp. 2-3.) The Commission declined to resolve the issue.

68. Initially, the Commission claimed that D.19-10-001 "provided sufficient direction for treatment of banked RECs." (D.23-06-006, at p. 44.) It stated that the utilities "should apply the [RPS Benchmark] for the year in which they use the banked REC." (*Id.*)

69. The Commission later clarified that this statement did not specifically address RECs banked before 2019. (D.24-08-004, at p. 5.) The Commission ultimately acknowledged that D.19-10-001 did not directly speak to this issue. (11:72:APP2567.)

70. Meanwhile, the Commission issued a series of inconsistent interim decisions concerning pre-2019 banked RECs.

71. For example, the Commission's 2024 and 2025 SCE ERRA Forecast Decisions approved SCE's approach to assign no value to pre-2019 banked RECs in the indifference adjustment when those RECs are used for utility customer compliance. (D.23-11-094, Southern California Edison Company's 2024 Energy

Resource Recovery Account Forecast (Dec. 1, 2023) at p. 53; D.24-12-039, Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue Requirement (Dec. 23, 2024) at p. 68.) Thus, in SCE's territory, Later-Departed customers received no value for RECs they paid for.

72. In contrast, in PG&E's 2024 and 2025 ERRA Forecast Decisions, the Commission approved PG&E's proposal to value pre-2019 banked RECs at the current RPS Benchmark, and to apply that value to the indifference adjustment vintage associated with the year the REC was generated. (D.24-12-038, Decision Approving Pacific Gas and Electric Company's 2025 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2025 Electric Sales Forecast (Dec. 20, 2024) at pp. 17, 68-70; D.23-12-022, Decision Adopting the Electric Revenue Requirements and Rates Associated with the 2024 Energy Resource Recovery Account [etc.] (Dec. 19, 2023) at p. 17; 8:34-23:APP1807 [describing PG&E's proposal]; 3:28:APP0571-73.) Thus, in PG&E's territory, Later-Departed customers received credit for pre-2019 banked RECs in past rate cases, eliminating the subsidy for current PG&E customers.

73. None of these decisions offered permanent guidance or an evaluation of whether the approved approaches maintained indifference. (*See, e.g.*, D.23-11-094, at pp. 53, 60 [describing "an interim solution"]; D.24-12-039, at p. 68 [adopting SCE's proposal "for this proceeding"].) The issue remained unresolved.

8. In the 2026 ERRA Forecast proceeding, PG&E changed its previous approach and proposed to give no value to CCA customers who paid for a share of RECs banked before 2019 when those RECs are used to satisfy PG&E customers' compliance obligations in 2025 and 2026.

74. PG&E submitted its 2026 ERRA Forecast application on May 15, 2025. (1:01.1:APP0008.) Reversing its approach from prior years (*see* ¶ 72, *supra*), PG&E's application proposed to assign no value to CCA customers for pre-2019 banked RECs used for PG&E customers' compliance in 2025 or 2026 (*id.* at APP0030).

75. PG&E intends to use pre-2019 banked RECs for its customers' compliance in 2025 and 2026. (11:72:APP2562.) Although the exact quantity of RECs PG&E intends to use is confidential, CalCCA estimated that PG&E's proposal would shift "approximately $75 million in costs" to CCA customers. (10:56:APP2290-91.)

76. If PG&E's approach is adopted permanently for *all* pre-2019 banked RECs, including those used for compliance in future years, it could shift "over a billion dollars" to CCA customers. (10:56:APP2288, APP2293.)

77. CalCCA argued extensively to the Commission that PG&E's proposal caused a cost shift and violated the indifference statutes. (*See, e.g.*, 8:43.1:APP1877-78; 2:05:APP0239-43.) CalCCA explained that Later-Departed customers had paid for a portion of the pre-2019 banked RECs, and PG&E's proposal denied Later-Departed customers value or benefit for those RECs when PG&E uses them for its customers' RPS compliance. (8:43.1:APP1898-99.)

78. As an alternative, CalCCA proposed that PG&E value Later-Departed customers' share of pre-2019 banked RECs used for utility customer compliance at the current RPS Benchmark. (8:43.1:APP1918-19.) The RPS Benchmark reflects the current market value of a REC used for compliance purposes—i.e., the cost PG&E customers avoid when PG&E uses a pre-2019 banked REC. (*See* 3:28:APP0574-75.) CalCCA proposed applying that value as a credit in the indifference adjustment to the vintage for the year the REC was generated.

(10:60:APP2342-43.) Doing so, CalCCA explained, would eliminate the cost shift. (*Id.*)

9. The Commission declined to address whether PG&E's proposal to assign no value to RECs banked before 2019 violated statutory indifference mandates. Instead, it adopted PG&E's proposal as an interim measure but stranded RECs used in 2025.

79. The Commission issued its Decision on December 23, 2025. The Decision does not evaluate whether PG&E's pre-2019 banked REC proposal maintains indifference, stating "it would not be possible at this time" to consider that question. (11:72:APP2567.) Rather, the Commission finds PG&E's proposal "reasonable on an interim basis while awaiting a more comprehensive decision… in a rulemaking." (11:72:APP2562.) The Decision thus directs PG&E to assign no value to pre-2019 banked RECs used for utility compliance in 2025 and 2026. (*Id.*; APP2567, APP2608.)

80. While awaiting this "more comprehensive decision," the Decision directs PG&E to track pre-2019 banked RECs it uses for "2026 compliance," so that the Commission may correct errors it later identifies concerning those RECs. (11:72:APP2568, APP2612.)

81. The Decision does not order PG&E to track its use of pre-2019 banked RECs in *2025*. For those RECs, the Decision is final. (11:72:APP2567-68.)

82. CalCCA sought rehearing of the Decision as described below, following the discussion of the Commission's error related to Resource Adequacy ("RA").

C. The Commission implemented unlawful retroactive ratemaking related to the method for calculating the 2025 RA Benchmark.

1. After shifts in the market for RA benefitted CCA customers, the Commission held an expedited proceeding to revise the methodology for calculating the RA Benchmark.

83. RA refers to the requirement that utilities have sufficient resources available to ensure reliable electricity service, both locally and system-wide. (§ 380.) The RA Benchmark reflects the estimated value of energy capacity that can be used to satisfy RA requirements. (11:72:APP2553.)

84. For many years, the indifference adjustment and the method used to calculate it worked out largely in utility customers' favor. That is, from 2012 to 2023, procurement costs generally exceeded portfolio value, and so CCA customers paid higher indifference adjustments on their bills.

85. In 2024 and 2025, however, market conditions changed. Uncertainty caused by recent regulatory changes, and supply chain and other challenges in developing new resources, created scarcity in the market for system-wide RA (Request for Judicial Notice ("RJN") Exhibit 1 (Energy Division Staff Report of the 2024-2025 Resource Adequacy Market Price Benchmark (Feb. 26, 2025)) at p. 9), and prices for those assets increased. (*Id.* at p. 6.) As a result, the market value of the utilities' generation portfolios increased relative to utilities' procurement costs. (*Id.*) And, at least for some CCA customers, the indifference adjustment shifted from a charge to a credit on their bills. (*See id.*; 9:44:APP2001.)

86. With their own customers facing higher rates, and with some CCA customers seeing credits on their bills, the utilities asserted that the RA Benchmark was causing a cost shift and called for changes to its calculation methodology. (D.24-12-039, at pp. 9-10.)

87. The Commission has acknowledged that an indifference adjustment credit on CCA customers' bills does not necessarily suggest a cost shift between CCA customers and

utility customers. Rather, it can accurately reflect resource costs and values. (D.18-10-019, at p. 155.)

88. Nevertheless, in February 2025, the Commission opened proceeding R.25-02-005, in part to modify the RA methodology the utilities had criticized. (D.25-06-049, at p. 8.) The Commission expedited the proceeding so that updated rates could be implemented as quickly as possible. (*Id*. at p. 17.)

89. The proceeding centered on a Commission staff report that included various proposals for changing the methodology for calculating the RA Benchmark. (RJN, Ex. 1.) The staff report focused on the reduced volume of system-wide RA transactions included in the calculation of the 2025 Benchmark compared to previous years. Commission staff reasoned that a smaller volume of transactions *could* result in individual transactions having outsized influence on the Benchmark, which *could* make the ultimate indifference adjustment subject to manipulation. (*Id.* at pp. 5-6, 9.) However, the staff report did not include evidence of any such manipulation

occurring or evidence that the existing benchmark was actually inaccurate.[9]

90. Rather, the staff report speculated about whether certain factors *could conceivably* lead to the calculation methodology being inaccurate. (*Id*. at p. 5 [speculating, without citing any supporting evidence, that certain transactions "*may* be driven by market power"] (emphasis added); *id*. at p. 7 [observing that certain types of transactions "*may* not reflect genuine market prices"] (emphasis added).) Indeed, the staff report pointed out that normal market forces may have been responsible for the increased value of RA resources in recent years. (*Id*. at p. 9.)

2. The Commission adopted a new methodology for calculating the RA Benchmark and directed that it be applied retroactively to rates already being collected under the old methodology.

91. On June 27, 2025, the Commission issued Decision 25-06-049, Decision Adopting Changes to the Calculation of the RA Market Price Benchmark ("RA Decision"). The RA Decision

[9] Because the RA Benchmark is a component of the indifference adjustment, an inaccurate Benchmark could lead to a cost shift.

adopted the staff report's proposals for changing the methodology used to calculate the RA Benchmark. (D.25-06-049, at pp. 31-33.)

92. Significantly, the RA Decision directed that the new methodology should be applied in the utilities' upcoming 2026 ERRA Forecast proceedings—including the proceeding underlying the present Petition—to the calculation of the 2025 indifference adjustment. (*Id.* at pp. 29-30.)

93. The 2026 ERRA Forecast proceeding would true-up the 2025 rates, which were already being collected based on the 2025 forecasts approved earlier in the year based on the then-existing methodology. The RA Decision, however, changed the methodology for those 2025 rates mid-stream, requiring them to be trued-up *not* against a set of figures that would be determined in the same way as the adopted forecasts had been, but rather against a different set of figures entirely. (*See id.*)

94. The Commission stated that this retroactive application of the new RA methodology was necessary to comply with the statutory requirement that the Commission ensure ratepayer indifference. (*Id.*) But the Commission did not cite any concrete evidence that the 2025 transactions did not *actually*

reflect market conditions, and thus that the old methodology did not actually result in ratepayer indifference in 2025.

3. CalCCA filed a petition for review of the RA Decision on grounds including that it violated the rule against retroactive ratemaking.

95. CalCCA applied for rehearing of the RA Decision. The Commission denied that application in October of 2025. (D.25-10-061, Order Denying Rehearing of Decision 25-06-049 (Oct. 31, 2025).)

96. CalCCA then filed a Petition for Writ of Review of D.25-06-049 and D.25-10-061 on December 1, 2025, asking this Court to review and set aside the RA Decision. (*Cal. Community Choice Assn. v. P.U.C., et al.,* Third District Court of Appeal, Case No. C105174 ("RA Petition").)

97. CalCCA's RA Petition argues that retroactive application of the new methodology for calculating the RA Benchmark to 2025 rates violates the rule against retroactive ratemaking. The rule, set out in section 728, reflects a foundational policy choice: to ensure the reliability and stability of rates, the Commission may not alter rates that have already been approved and collected, but rather is limited to prospective

action. By applying the new RA methodology to rates that were already being collected in 2025 under a previously approved methodology, the Commission engaged in unlawful retroactive ratemaking.

98. The RA Petition also shows that the Commission's decision to apply the new RA methodology retroactively to 2025 rates was not supported by adequate findings or substantial evidence and constituted an abuse of discretion. The Commission premised its decision to retroactively apply the new methodology on the idea that the prior methodology would have produced inaccurate results and thus failed to ensure ratepayer indifference. But the Commission did not include any finding that the prior methodology actually produced inaccurate results for 2025, and no concrete evidence in the record established such inaccuracies. In light of the statutory requirement to ensure actual indifference, the Commission's decision to retroactively impose hundreds of millions of dollars in additional costs on CCA customers without evidence of actual inaccuracies in the prior method was an abuse of discretion.

99. This Court denied the RA Petition on June 25, 2026. CalCCA subsequently petitioned the Supreme Court for review.

(*Cal. Community Choice Assn. v. P.U.C.*, Case No. S297373.) As of this filing, the petition for review is pending before the Supreme Court.[10]

4. In this Decision, the Commission implemented the unlawful retroactive ratemaking it ordered in the RA decision, approving PG&E's retroactive application of the new RA Benchmark methodology to true up 2025 rates.

100. The RA Decision directed Commission staff to calculate the 2025 Final RA Benchmarks using the new methodology. (D.25-06-049, at pp. 29-30.)

101. PG&E used the new RA Benchmark, calculated under the new methodology, to true up the 2025 forecast indifference adjustment rates—even though those rates had been set and were already being collected under the prior methodology. (11:74:APP2631-32.)

102. CalCCA objected that the RA Decision was invalid for the reasons later presented in its RA Petition. CalCCA further explained that any decision approving PG&E's application of the

[10] See footnote 1, *supra*, regarding CalCCA's anticipated request that the Court sequence its decision on section II of the Argument here to follow resolution of the RA Petition.

new RA methodology to true up 2025 rates would implement and perpetuate unlawful retroactive ratemaking. (9:43.2:APP1954-72; 11:69:APP2517.)

103. Despite CalCCA's warnings, in this Decision, the Commission carried out the RA Decision's unlawful directive to apply the new RA methodology retroactively by approving PG&E's proposed rates calculated using the new RA methodology. (11:72:APP2553.)

D. CalCCA filed an application for rehearing of the 2026 ERRA Forecast Decision to show that the Commission's decisions to apply zero value to RECs banked before 2019 and to implement retroactive ratemaking are unlawful.

104. The Commission's Decision in PG&E's 2026 ERRA Forecast proceeding both (1) approves PG&E's proposal to assign zero value to RECs banked before 2019 and (2) implements the new RA methodology and retroactively applies it. (11:74:APP2639, 53.)

105. The new RA methodology, together with the pre-2019 banked REC methodology and other changes approved in the Decision, sharply increased CCA customers' indifference adjustment rates. For example, for some CCA customers,

indifference rates increased over 900% from the prior year. (11:74:APP2645, fn. 68.)

106. In dollars, these increases are significant. For an average CCA customer in Stockton, for example, the Decision was forecast to increase their electricity bills more than $41 per month, or $492 total in 2026. (11:66:APP2482-83; *id.* at fn. 11.)

107. On January 12, 2026, CalCCA applied for rehearing of the Decision. (11:74:APP2623.) CalCCA argued that the Decision's treatment of pre-2019 banked RECs caused an impermissible cost shift and violated the indifference statutes. (11:74:APP2633.) It further argued that, by failing to evaluate whether its approach to pre-2019 banked RECs violated indifference, the Decision was arbitrary and not supported by adequate findings. (11:74:APP2634.) Finally, CalCCA argued that the Decision was invalid and void because it implemented the unlawful retroactive ratemaking ordered in the RA Decision. (11:74:APP2643-46.)

108. As of this writing, the Commission has not acted on CalCCA's application for rehearing.

PRAYER FOR RELIEF

WHEREFORE, Petitioner CalCCA respectfully asks this Court to grant relief, as follows:

1. Issue a writ of review to determine the lawfulness of D.25-12-027;

2. Direct the Commission to certify its record in the subject proceeding to this Court;

3. Enter judgment setting aside D.25-12-027, and remand with instructions to:

a. Evaluate whether the proposed methods for valuing pre-2019 banked RECs ensure indifference and make appropriate findings;

b. Ensure Later-Departed CCA customers receive benefit from or credit for pre-2019 banked RECs when those RECs are used for PG&E customer compliance;

c. Direct PG&E to apply the methodology for calculating the RA Benchmark in place before D.25-06-049 in trueing up 2025 rates; and

d. Correct any over- or under-collections resulting from the Commission's errors.

4. Grant such other relief as the Court may deem just and proper.

DATED: July 17, 2026

SHUTE, MIHALY &
WEINBERGER LLP

By: ______________________________
AARON M. STANTON
SHANTHI M. CHACKALACKAL

Attorneys for California
Community Choice Association

VERIFICATION ON BEHALF OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION

I, Elizabeth Vaughan, declare as follows:

I am Chief Executive Officer of Petitioner CalCCA, and I make this verification on behalf of Petitioner. I have read the foregoing Petition for Writ of Review and know its contents, and the facts therein stated are true to my own knowledge, except as to those matters stated on information and belief; as to those matters, I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on July 16, 2026, at Gytheio, Greece.

Elizabeth Vaughan
Chief Executive Officer

MEMORANDUM OF POINTS AND AUTHORITIES

STANDARD OF REVIEW

Any party aggrieved by a Commission decision may petition for a writ of review in the Court of Appeal. (§ 1756(a).) A court ordinarily has no discretion to deny a timely-filed petition if it appears that the petition may be meritorious, because review by extraordinary writ is the exclusive means of judicial review of Commission decisions. (*PG&E Corp. v. P.U.C.* (2004) 118 Cal.App.4th 1174, 1193; § 1759.)

Section 1757 establishes the scope of review in this ratesetting matter. As relevant here, the Court must set aside a Commission decision on appeal if (1) the Commission has "acted without, or in excess of, its powers or jurisdiction;" (2) the Commission "has not proceeded in the manner required by law;" (3) the decision "is not supported by the findings;" or (4) the decision was "an abuse of discretion." (§ 1757(a)(1)-(3), (5).) In addition to procedural errors, an agency's failure to apply the correct substantive legal standard results in a failure to proceed in the manner required by law. (*City of Marina v. Bd. of Trustees of Cal. State Univ.* (2006) 39 Cal.4th 341, 355, 365-66 [agency's incorrect determination that the California Environmental

Quality Act required guarantees for mitigation to be considered "feasible" constituted failure to proceed in the manner required by law].)

The Commission receives no special deference for its interpretations of the Public Utilities Code. (*Center for Biological Diversity, Inc. v. P.U.C.* (2025) 18 Cal.5th 293, 304, 306.) Where the agency's interpretation of "the meaning and legal effect of a statute" is at issue, the reviewing court must apply its "independent judgment de novo to the merits of the legal issue before it." (*Id.* at p. 305, quoting *Yamaha Corp. of America v. State Bd. of Equalization* (1998) 19 Cal.4th 1, 7, 8 ("*Yamaha*").) "[A] court does not defer to the agency's view of whether [an agency regulation] lies within the scope of the lawmaking authority delegated by the Legislature." (*Id.* at pp. 305-06.) Moreover, agency interpretations warrant no deference where the agency has issued inconsistent interpretations over time. (*Yamaha*, 19 Cal.4th at p. 13.)

Here, the Decision is not entitled to deference. The statutory interpretation question at issue—whether the Decision's treatment of banked RECs maintains statutory indifference—concerns whether the Commission has acted within the scope of its authority. Moreover, because the Decision declined to evaluate this question on the merits, the Commission has not offered any interpretation to which the Court can defer. Finally, to the extent that the Commission approved past proposals for the treatment of pre-2019 banked RECs, those proposals were inconsistent. (*Compare* D.23-11-094, at p. 53 *and* D.24-12-039, at p. 68 [approving proposal to assign zero value to pre-2019 banked RECs], *with* D.24-12-038, at pp. 17, 68-70 *and* D.23-12-022, at p. 17 [approving proposal to value pre-2019 banked RECs at current RPS Benchmark].) Such conflicting positions are not entitled to deference.

ARGUMENT

I. The Decision to assign Later-Departed CCA customers zero value for RECs banked before 2019 when they are used to satisfy current utility customer compliance obligations fails to ensure customer indifference and conflicts with prior Commission guidance regarding the use of RECs.

Before 2019, customers who would later depart utility service for CCAs paid for RECs that PG&E is now using to satisfy its own customers' current RPS compliance obligations—obligations that PG&E's current customers would otherwise be required to meet absent the pre-2019 RECs. Under the PG&E

proposal approved by the Decision, PG&E's current customers receive the entire value of those RECs. The Later-Departed CCA customers who paid a substantial share of the cost do not receive, and have never received, any value or benefit for their payments.

As explained below, the Decision's cost shift from current PG&E customers to Later-Departed CCA customers violates the indifference statutes. Section 366.2(g) requires the Commission to reduce CCA customers' indifference charges by the value of benefits that remain with utility customers, and sections 365.2, 366.2(a)(4), 366.2(d)(1), and 366.3 forbid cost shifts between the two groups. To maintain indifference, the Commission must provide value to Later-Departed customers for the portion of the banked RECs they paid for when those RECs are used for current utility customers' RPS compliance. Commission guidance supports this analysis.

The Decision approves PG&E's proposal as "reasonable" without evaluating whether it maintains indifference. By skirting a question it had a mandatory duty to answer, the Commission also abused its discretion and rendered the Decision unsupported by findings on a material issue.

A. The Commission's failure to credit Later-Departed CCA customers for the value of banked RECs they paid for, and for which they never received any benefit, violates the indifference statutes.

1. The indifference statutes prohibit cost-shifting between CCA and utility customers.

The statute governing the formation and implementation of CCAs prohibits cost-shifting between CCA customers and utility customers. The Legislature's express intent in enacting section 366.2 was "to prevent any shifting of recoverable costs between customers." (§ 366.2(d)(1).) Thus, the Legislature commanded that the creation of a CCA "shall not result in a shifting of costs between the customers of the [CCA] and the [utility's] … customers." (§366.2(a)(4); *see also* §§ 366.3, 365.2[11] [also prohibiting cost shifting].)

The prohibition on cost-shifting requires equitable treatment for both CCA and utility customers. For example, section 366.2 prohibits cost shifts "between" utility and CCA customers. (§§ 366.2(a)(4), 366.2(d)(1) [showing that the prohibition is reciprocal].) Similarly, in addition to protecting

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[11] Section 365.2 concerns load-serving entities other than CCAs.

utility customers from cost shifts, section 366.3 directs the Commission to ensure that CCA customers "do[ ] not experience any cost increases" from costs that are not attributable to them.

2. The indifference statutes require that CCA customers receive the value of benefits they paid for that are used by utility customers.

To prevent cost-shifting, the Legislature directed the Commission to enact a cost-recovery mechanism with specific features. Section 366.2(f) requires CCA customers to reimburse the utility for the net costs of power the utility procured on their behalf before they departed for CCA service. The indifference adjustment implements this directive. (11:72:APP2548-49.)

At the same time, section 366.2(g) also directs that CCA customers must be compensated for the value of any *benefits* of resources, procured on their behalf, that remain with utility customers. (§ 366.2(g).) When CCA customers paid for a resource that benefits utility customers, CCA customers may either receive a share of that resource's benefits, or they may receive an equivalent credit against their indifference adjustment rates. (*Id.*) This requirement prevents CCA customers from subsidizing utility customers.

The indifference statutes are mandatory. (D.20-01-030, at p. 12 ["Sections 365.2, 366.2(a)(4), 366.2(d) and 366.3 require us to prevent any cost shifting"]; D.25-06-049, at p. 2; D.18-07-009, at p. 15.) The Commission *must* ensure indifference between CCA and utility customers. (*Id.; Cal. Community Choice Assn. v. P.U.C.* (2024) 103 Cal.App.5th 845, 858-59.)

The Commission has implemented these statutes to prevent cost shifts from RECs. The Commission concluded that RECs have value related to their RPS eligibility, and this value remains with utility customers. (D.11-12-018, at p. 17.) Further, the Commission has found that utility customers realize RECs' value when the RECs are used for compliance purposes. (D.19-10-001, at pp. 27-30, 49.) CCA customers shared in the RECs' procurement costs. (7:34-01:APP1695-96.) Thus, to ensure CCA customers receive value for RECs they paid for when the RECs are used for utility customers' compliance, the Commission applies a credit to the indifference adjustment at the RPS Benchmark. (D.19-10-001, at pp. 27-30, 49; *see also* D.25-06-049, at p. 4 [CCA customers are "entitled to any residual procurement benefits enjoyed by the incumbent [utility] attributable to the [CCA] customer"]; § 366.2(g).)

The Commission directed that these methods should apply to RECs generated *beginning* January 1, 2019. (D.19-10-001, at p. 47.) But nothing in prior Commission decisions suggests that the principles underlying these methods do not apply equally to RECs banked before January 1, 2019.

CalCCA and others have repeatedly asked the Commission to permanently resolve how to treat pre-2019 banked RECs. (D.23-06-006, at p. 44; D.24-08-004, at pp. 2-3.) It has thus far declined to do so. (D.24-08-004, at p. 5 [deferring decision].) The solutions the Commission *has* offered have been inconsistent and, in any event, have been only interim measures. (D.23-11-094, at pp. 53, 60 [adopting SCE's proposal to assign zero value to pre-2019 banked RECs in the indifference adjustment as "an interim solution"];[12] D.24-12-039, at p. 68 [adopting SCE's proposal "for this proceeding"]; 8:34-23:APP1807 [describing PG&E's proposal to credit CCA customers for pre-2019 banked RECs at the RPS

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[12] In D.23-11-094, the Commission said it "ha[d] not, to this date, found that SCE's … customers owe additional credits to [CCA] customers when SCE uses RECs banked in or before 2018." (D.23-11-094, at p. 53.) This statement confirmed the Commission had not directly resolved how to treat pre-2019 banked RECs. It did not permanently reject providing credits to CCA customers for pre-2019 banked RECs.

Benchmark]; 3:28:APP0571-73 [same]; D.24-12-038, at pp. 17, 68-70 [adopting PG&E's proposal]; D.23-12-022, at p. 17 [same].) None of these decisions analyzed whether the Commission's treatment of pre-2019 banked RECs ensured indifference.

The indifference statutes require Later-Departed CCA customers to receive value for the share of pre-2019 banked RECs they paid for. Nothing in Commission guidance suggests—or could suggest—otherwise. (*See Carmel Valley Fire Protection Dist. v. State* (2001) 25 Cal.4th 287, 299-300 [a regulation may not contradict a statute].)

3. Later-Departed CCA customers paid for their portion of RECs banked before 2019; the Decision's failure to credit them for the benefits of those RECs results in a cost shift benefiting PG&E customers.

The Decision provides no value in the indifference adjustment for RECs banked before 2019 when they are used for current PG&E customers' RPS compliance. In other words, even though Later-Departed CCA customers paid for a share of the costs of pre-2019 banked RECs, the Decision allows PG&E customers to realize nearly all of the RPS compliance benefits. Later-Departed customers receive no benefit or value. In approving this scheme, the Decision unlawfully shifts the costs of

PG&E customers' RPS compliance to Later-Departed CCA customers.

The value of a REC is realized when the REC is used for compliance purposes. (D.19-10-001, at p. 49 ["RECs have value to the [utility] when they use the RECs."].) That value is equal to the compliance costs that PG&E *avoids* by using the banked RECs. (*See* D.11-12-018, at p. 24.) For example, if PG&E did not use a banked REC for compliance purposes, it would need an alternative, such as procuring a *new* REC on the market to fulfill its RPS obligations. (3:28:APP0573-75; 8:43.1:APP1921.) The cost of the new REC would be approximately the current RPS Benchmark, which reflects the RECs' compliance value. (D.19-10-001, at p. 7.) The Commission recognized this value in D.19-10-001, when it required that any REC banked *after* January 1, 2019 and used for utility compliance in a subsequent year be valued for indifference purposes at the RPS Benchmark—i.e., the utility's avoided cost—for that subsequent year. (D.19-10-001, at pp. 27-30.)

But RECs have value when used for compliance purposes regardless of when they were generated and banked. That is, PG&E's avoided compliance cost is the same, regardless of whether the REC PG&E uses was banked in 2013 or 2023. Either way, current utility customers receive value because the REC satisfies a compliance obligation that they would be paying for—at the same current market price—if not for the use of the REC. (3:28:APP0573-75; 8:43.1:APP1921.)

Current PG&E customers, however, are not the only ones who paid for RECs banked before 2019. Current PG&E customers paid for only a portion of those RECs. (7:34-01:APP1709.) The remainder of the RECs were paid for by "Later-Departed" customers who *were* PG&E customers when the RECs were banked, but who subsequently departed for CCA service. (*Id.*) Because CCA service has expanded significantly since 2019, Later-Departed customers' shares of PG&E's pre-2019 banked RECs are significant. (*Id.*) For example, Later-Departed customers made up 63% of PG&E customers in 2013, and 57% of PG&E customers in 2017. (*Id;* 8:43.1:APP1914.) Later-Departed customers thus paid for approximately 63% of the costs of RECs generated in 2013 and 57% of the costs of RECs generated in 2017. (*Id.*)

Under the Decision, Later-Departed customers receive *no value* when the pre-2019 banked RECs they paid for are used for

PG&E customer compliance. (7:34-01:APP1711; 3:28:APP0551.) These RECs do not satisfy any compliance obligation of Later-Departed CCA customers when used by PG&E.[13] (*Id.*) Nor do Later-Departed CCA customers receive any credit against their indifference adjustment payments. (*Id.*) Instead, PG&E customers receive all of the value from use of the RECs, despite paying for only a share of the costs of those RECs.

The Commission's decision to assign Later-Departed customers no value for the pre-2019 banked RECs that they paid for violates the indifference statutes. Under section 366.2(g), the Commission "shall" reduce CCA customers' indifference payments for resources procured on their behalf "by the value of any benefits that remain with [utility] customers, unless the [CCA customers] are allocated a fair and equitable share of those benefits." The Decision violates section 366.2(g) because (1) Later-Departed customers paid for the pre-2019 banked RECs, (2) the benefits of the RECs remain with utility customers, and

[13] CCAs are responsible for their own customers' RPS compliance obligations. (§§ 399.15(a), 399.13(a)(3), 399.13(b) [setting out compliance requirements for "retail sellers"]; § 399.12(j) [CCAs are retail sellers].)

(3) the Decision gives Later-Departed customers neither value nor a share of the benefits.[14]

The Decision also results in a prohibited cost shift. Under the Decision, because both current PG&E customers and Later-Departed customers previously paid for a share of the pre-2019 banked RECs' costs, but only current PG&E customers realize the RECs' RPS compliance value, Later-Departed customers' payments are subsidizing current PG&E customers' RPS compliance. This unwarranted subsidy violates the statutory prohibition of cost shifts between CCA and utility customers. (*See* §§ 366.2(a)(4), 366.2(d)(1), 366.3.) In so violating the indifference statutes, the Commission exceeded its statutory authority and failed to proceed in the manner required by law. (*See* §

[14] The Decision could have provided a credit in the indifference adjustment to Later-Departed customers for their share of the RECs, as CalCCA proposed. (8:43.1:APP1918-19.) PG&E argued before the Commission that CalCCA's proposal would result in PG&E customers double-paying for RECs, because PG&E customers had already paid a credit for the RECs to Previously-Departed CCA customers when the RECs were banked. (9:44:APP2013.) But current PG&E customers did *not* pay for *Later-Departed Customers' share* of the RECs in the year they were banked. Under CalCCA's proposal, the credit would have addressed only that latter portion of the REC. (7:34-01:APP1696-97, APP1707-16.)

1757(a)(1)-(2); *City of Marina*, 39 Cal.4th at pp. 355, 365-66 [by applying an incorrect legal standard, the agency did not proceed as required by law].)

B. The Commission's failure to evaluate whether PG&E's proposal violates indifference constitutes an abuse of discretion and means the Decision is not supported by adequate findings.

The Decision to assign zero value to CCA customers for pre-2019 banked RECs did not rely on an analysis of whether that approach upheld statutory indifference principles. Rather, reasoning that D.19-10-001 did not specifically address how to account for pre-2019 banked RECs, the Commission punted the question to a later rulemaking proceeding. Instead, the Commission found it "reasonable to adopt PG&E's Pre-2019 Banked RECs methodology on an interim basis" and "until further Commission guidance is put into place."[15] (11:72:APP2567.)

The Commission's failure to evaluate the merits of PG&E's proposal for pre-2019 banked RECs itself constitutes reversible

[15] For RECs used in 2025, however, the Decision is permanent in its effect. (*See* § I.C, below.)

error on two grounds: it represents an abuse of discretion and resulted in a Decision that is not supported by adequate findings.

Where the Commission has a mandatory duty to ensure that rates meet a certain standard, it abuses its discretion by failing to consider whether rates satisfy that standard. (See *Securus Technologies, LLC v. P.U.C.* (2023) 88 Cal.App.5th 787, 803 (citation omitted) [under the abuse of discretion standard, "the court must ensure that an agency has adequately considered all relevant factors, and has demonstrated a rational connection between those factors, the choice made, and the purposes of the enabling statute."].) For example, in *City and County of San Francisco v. Public Utilities Commission*, the Commission erred in "refusing to consider the merits" of an alternative approach for addressing certain tax expenses where it had a duty to ensure that rates were just and reasonable. (6 Cal.3d 119, 126, 129-30.) In that case, the Commission concluded that due process required basing rates on the utility's actual tax expenses, which were unreasonable in light of available alternatives. (*Id.* at pp. 126, 127.) Because the Commission was obliged to prevent unreasonable rates, the Court held that the "commission abused its discretion in expressly refusing to consider" alternatives. (*Id.*

at p. 129; *see also U.S. Steel Corp. v. P.U.C.* (1981) 29 Cal.3d 603, 608-10 [Commission erred in failing to consider economic effects of rates on shippers where statute required the commission to "give due consideration to" such effects]; *City of Los Angeles v. P.U.C.* (1975) 15 Cal.3d 680, 684, 704 [Commission erred by failing to consider alternative lawful approaches to certain tax deductions despite its "mandatory" obligation to ensure just and reasonable rates]; *N. Cal. Power Agency v. P.U.C.* (1971) 5 Cal.3d 370, 376-79 [Commission erred by failing to evaluate antitrust implications of its decision where it had a duty to ensure its decision supported the public interest, including the public interest in competition].)

Here, the Commission has a mandatory duty to ensure that its rates ensure indifference between utility and CCA customers. The statutes requiring indifference use mandatory language. (§ 366.2(a)(4) ["The implementation of a [CCA] shall not result in a shifting of costs…."]; § 366.2(g) [CCA customers' indifference payments "shall be reduced by the value of any benefits that remain with [utility] customers"]; § 366.3 [Utility customers "shall not experience any cost increase…;" "[t]he commission shall also ensure that departing load does not experience any cost increases….”].) The Commission itself has recognized that ensuring indifference is mandatory. (D.25-06-049, at p. 2 [“The Commission is statutorily mandated to ensure that the movement of customers from [utilities to CCAs] does not shift costs.”]; *see also id.* at pp. 5, 11, 12, 17, 29 [referencing the indifference “mandate”]; *see also* D.20-01-030, Order Modifying Decision 18-10-019 and Denying Rehearing of the Decision, As Modified (Jan. 21, 2020) at pp. 4-5 [referencing “our statutory duty” to prevent cost shifting].) Likewise, the only court to consider the indifference statutes held that their plain language “charges the Commission with ensuring that [CCA expansion] … will not result in cost shifting between CCA and non-CCA customers.” (*Cal. Community Choice Assn.*, 103 Cal.App.5th at p. 858.)

The Commission’s mandatory duty to ensure that rates maintained indifference required the Commission to consider whether PG&E’s approach to pre-2019 banked RECs violated indifference. But the Commission declined to consider this question. Instead, it determined that “it would not be possible at this time” to evaluate the parties’ proposals, punted the issue to a later rulemaking, and adopted PG&E’s proposal on an interim basis without evaluating its merits. (11:72:APP2567, APP2608.) By failing to consider indifference, the Commission failed to consider a factor relevant to—and, indeed, required in—its decision under the governing statute. It thus abused its discretion.

Relatedly, the Commission's failure to consider whether PG&E's approach ensured indifference resulted in a Decision that is not supported by adequate findings. Section 1705 requires the Commission's decisions to "contain, separately stated, findings of fact and conclusions of law… on all issues material to the order or decision." (§ 1705; *Cal. Manufacturers. Assn. v. P.U.C.* (1979) 24 Cal.3d 251, 258.) "Every issue that must be resolved to reach [the] ultimate finding is material to the order or decision, and findings are required of the basic facts upon which the ultimate finding is based." (*Greyhound Lines, Inc. v. P.U.C.* (1967) 65 Cal.2d 811, 813.)

Where the Commission has an obligation to consider a particular factor in executing a mandatory duty, that factor is necessarily "material" to the decision, and the Commission must make a finding on that issue. For example, in *United States Steel Corporation v. Public Utilities Commission*, the Court held that the economic effects of certain rates on shippers was "material" to the Commission's decision because a statute required the Commission to consider such economic factors in establishing rates. (29 Cal.3d at pp. 608-10.) Similarly, in *Northern California Power Agency v. Public Utilities Commission*, the Court held that the Commission erred by failing to make a finding concerning the antitrust implications of its decision where the Commission had a duty to consider those implications. (5 Cal.3d 370, 377, 379, 380-81 ["[T]here are no findings of fact which could possibly be construed as dealing with antitrust considerations."].)

Here, as explained above, the Commission has a mandatory duty to consider whether its rates ensure indifference. The treatment of pre-2019 banked RECs is a component of rates. Whether PG&E's treatment of pre-2019 banked RECs maintains indifference is thus material to the Decision.

The Commission, however, did not make any finding as to whether PG&E's proposal to assign zero value to pre-2019 banked RECs ensures indifference. The Commission's findings instead contained the bare conclusion that PG&E's approach was reasonable as an interim method, with no analysis of whether it ensured indifference. (11:72:APP2608 [Finding of Fact 15].) As in

Northern California Power Agency, the total absence of any substantive analysis of indifference means the Decision's reasonableness finding cannot be construed as dealing with indifference. Because the issue of whether PG&E's proposal maintained indifference was material to the Decision, and the Commission made no finding addressing that issue, the Decision is not supported by the findings.

C. The Decision's requirement to track credits used in 2026 strands credits used in 2025 and does not fix the violation of the indifference statutes.

After calling for a separate rulemaking concerning the valuation of pre-2019 banked RECs, the Decision orders PG&E to track how it uses pre-2019 banked RECs for compliance in 2026. (11:72:APP2567, APP2612.) The Decision explains that this tracking procedure will allow the Commission to apply guidance from any subsequent rulemaking to RECs used in 2026. (11:72:APP2568.) But the Decision, without explanation, does not require tracking for pre-2019 banked RECs used for compliance in *2025*. (11:72:APP2612.)

The Commission's tracking procedure for RECs used in 2026 does not cure the Decision's violation of the indifference mandate. The tracking procedure strands RECs used for compliance in 2025. As to those RECs, the Decision will allow violations of the statutory indifference mandates to occur, even if the Commission finds in a subsequent rulemaking that the Decision's adopted approach violates indifference. The statutory indifference mandates do not tolerate this outcome. (§§ 366.2(a)(4), 366.2(g), 366.3 [prohibiting cost shifting].) Moreover, the Commission offers no rational explanation for treating RECs used in 2025 differently from those used in 2026, and its Decision is therefore arbitrary. (*See Securus Technologies LLC*, 88 Cal.App.5th at p. 803.)

*　　*　　*

The Decision's treatment of pre-2019 banked RECs violates the indifference statutes, constitutes an abuse of discretion, and is not supported by the findings. The Decision must be reversed.

II. The Decision is unlawful because it implements an unlawful retroactive ratemaking and a decision that was not supported by the findings.

The Decision is also unlawful because it implements the RA Decision's ultra vires directive to retroactively apply a new methodology for calculating the RA Benchmark. Because it carries out an unlawful decision, the Decision is unlawful in its own right.

The claims in this Petition concerning the Decision's invalidity are premised on the RA Decision's invalidity. Although this Petition describes the RA Decision and the Commission's errors in issuing it (§ II.A, below) to provide the context necessary to show that the current Decision is invalid, CalCCA does not request review of the RA Decision—or otherwise ask the Court to adjudicate the errors described in section II.A, below—in this Petition. Rather, the RA Decision is challenged in the RA Petition, which is currently pending before the Supreme Court. Because the claims in this Petition depend on the resolution of the RA Petition, CalCCA anticipates requesting that this Court sequence its decision on Section II of this Argument so that the RA Petition may be resolved first.

As CalCCA is arguing in the RA Petition, the Commission had no authority to retroactively apply the new RA methodology to 2025 rates. Section 728 authorizes the Commission to fix rates "to be *thereafter observed and in force*." (§ 728, emphasis added.) This section imposes a fundamental limit on the Commission's jurisdiction: it may fix rates prospectively, but it may not engage in retroactive ratemaking—and thus cannot roll back rates that have already been approved. (*Pacific Tel. & Tel. Co. v. P.U.C.* (1965) 62 Cal.2d 634, 650-52; *Southern Cal. Edison Co. v. P.U.C.* (1978) 20 Cal.3d 813, 817-18 ("*Edison*").)[16] California courts have recognized a limited exception to this rule: the prohibition on retroactive ratemaking applies to quasi-legislative "general ratemaking," but not to ministerial rate adjustments that involve merely plugging actual costs into previously approved formulas. (*Edison*, 20 Cal.3d at pp. 828-30; *City of Los Angeles v. P.U.C.*, 15 Cal.3d at pp. 692, 695.)

The RA Decision's retroactive application of the new RA methodology constituted general ratemaking and violated the prohibition on retroactive ratemaking. It was also not supported by the findings. It was therefore unlawful. Because *this* Decision implements the unlawful and unsupported RA Decision, it is itself unlawful.

[16] Section 728 applies not only to rates, but also to "rules" or "practices" affecting rates—including methods for calculating rates. (§ 728.)

A. As shown in CalCCA's pending RA Petition, the RA Decision violated the prohibition on retroactive ratemaking and was not supported by adequate findings.

1. The change to the methodology for calculating the RA Benchmark constituted general ratemaking, and its retroactive application violated the rule against retroactive ratemaking.

As argued in the RA Petition, the Commission's change to the indifference methodology in the RA Decision constituted general ratemaking subject to the prohibition on retroactive ratemaking. Under *Edison*, general ratemaking involves proceedings "in which many variables are taken into account and broad policies are formulated" to determine a rate that will cover the utility's costs and/or allow it to receive a reasonable rate of return on invested capital. (*Edison*, 20 Cal.3d at pp. 816, 818, 828.) In contrast, the exception to the rule against retroactive ratemaking is limited to the "narrowly restricted and semi-automatic" application of mathematical formulas involving actual, verifiable costs. (*Id.* at pp. 828-29, 830.)

In changing the RA methodology, the Commission changed the basis for the rate itself. It considered many variables—including what constituted a "market-based transaction" (D.25-

06-049, at pp. 21-22), and whether declining transaction volumes in 2024 and 2025 required a methodology change (*id.* at 16)—to make determinations that implicated broad policy concerns about how best to measure the market value of the utilities' generation portfolios and whether the RA methodology ultimately ensured ratepayer indifference. (*Id.* at 33.)

Further, the RA Benchmark is a Commission-determined proxy for portfolio value—a subjective determination, not "empirical data" that can be "definitively established by reference to the utilities' books." (*Edison*, 20 Cal.3d at pp. 828-29.) Rather than comparing forecasted costs to actual costs, the Commission revised its very definition of portfolio market value. Under *Edison*, this was general ratemaking.

The RA Decision required that the new RA methodology be applied retroactively to rates that were already being collected in 2025 under a previously approved methodology. This retroactive application violated the rule against retroactive ratemaking.

2. The RA Decision is unlawful because it is not supported by adequate findings.

The RA Decision is also unlawful because it is not supported by adequate findings. All Commission decisions must contain findings of fact on all issues "material" to the decision. (§ 1705.) A decision that is not supported by the findings is subject to reversal. (§§ 1757, § 1757.1; *Burlington N. & Santa Fe Ry. Co. v. P.U.C.* (2003) 112 Cal.App.4th 881, 891-92.)

The RA Decision's retroactive application of the new RA methodology was premised on the assumption that the 2025 rates the old methodology produced were inaccurate (D.25-06-049, at p. 17), making the accuracy of those rates "material" to the decision (*See Greyhound Lines*, 65 Cal.2d at p. 813). Yet the Commission never found that the 2025 rates were actually inaccurate. It found only that the old methodology had features that *could* produce inaccurate results in certain circumstances, including that the old methodology was "vulnerable to manipulation" (D.25-06-049, at pp. 29-31), and that certain transactions *might* not reflect market value (*id.* at pp. 22-24).

None of these findings established that the 2025 results were in fact inaccurate. There is a critical difference between accepting that a methodology may have "vulnerabilities," or that the new methodology *could* yield more accurate results in the future, and accepting that the 2025 results *were* inaccurate. Thus, none of the Commission's findings supported its decision to apply the revised methodology retroactively. (*See, e.g.*, *Cal. Manufacturers*, 24 Cal.3d at pp. 255-56, 259 [where a Commission decision to change its methodology for spreading rate increases was justified on the assumption that the change would conserve natural gas resources, the findings were insufficient because the Commission made no specific finding that the new methodology would actually result in more conservation than alternative approaches].)

B. This Decision is unlawful in its own right because it implements the RA Decision's unlawful retroactive ratemaking and carries out a decision not supported by the findings.

1. The Decision approves the unlawful retroactive application of the new method for calculating the RA Benchmark.

In implementing the RA Decision, this Decision carries out the unlawful retroactive application of the new RA methodology. First, Commission staff calculated new final 2025 RA Benchmarks using the RA Decision's revised methodology. (11:74:APP2639-41.) PG&E then used the new Benchmark to true up the 2025 forecasted indifference adjustment rates, which had been set under the prior methodology. (*Id.*) In this Decision, the Commission reviewed and approved that true-up, finding the indifference adjustment revenue requirement resulting from the new RA methodology to be "reasonable." (11:72:APP2548.) The Decision thus carries out the RA Decision's unlawful retroactive ratemaking, approving its implementation in PG&E's rates.

2. The Decision is invalid because it implements and perpetuates an unlawful decision.

An agency action based on an unlawful action is itself invalid. For example, "[a]n agency that exceeds the scope of its statutory authority acts ultra vires and the act is void." (*Water Replenishment Dist. of So. Cal. v. City of Cerritos* (2012) 202 Cal.App.4th 1063, 1072; *see also Turlock Irrigation Dist. v. Hetrick* (1999) 71 Cal.App.4th 948, 951.) Subsequent acts that implement or perpetuate the original, ultra vires act are themselves ultra vires and unlawful. (*Turlock*, 71 Cal.App.4th at p. 951 [where "[p]rovision of natural gas exceed[ed] the scope of power" granted to an irrigation district, acts "taken in furtherance of this unauthorized activity, such as execution of the contested gas supply, would be ultra vires"]; *see also Carr v. Kamins* (2007) 151 Cal.App.4th 929, 933 ["An order after judgment that gives effect to a judgment that is void on its face is itself void and subject to appeal."].) In keeping with this logic, the

California Supreme Court has held that a Commission decision based on an earlier, unlawful decision "must also be annulled." (*City of Los Angeles v. P.U.C.* (1972) 7 Cal.3d 331, 337-38 [annulling a decision fixing the amount of a utility's federal tax expense because "the rates therein… [were] based in part on" an earlier decision that was subsequently annulled].)

The Decision is unlawful because it implements an unlawful decision: it approves indifference rates calculated using the RA Decision's unlawful directive to retroactively apply the new RA methodology. (11:72:APP2553 [the 2025 final RA Benchmark was "calculated as ordered in [the RA Decision].") Because the RA Decision exceeded the Commission's statutory authority by imposing retroactive ratemaking in violation of Section 728, and the Decision implements the RA Decision, the Decision is itself invalid.

Likewise, the Decision is unlawful because it implements a decision that was not supported by adequate findings. The Commission's failure to support the RA Decision with adequate findings made that decision invalid. (§§ 1757, 1757.1; *Burlington N. & Santa Fe Ry. Co.*, 112 Cal.App.4th at pp. 891-92.) Since the RA Decision is invalid, so is every decision based on it. (*See, e.g.*, *Cal. Portland Cement Co. v. P.U.C.* (1957) 49 Cal.2d 171, 176 [holding that Commission orders based on erroneous findings must be annulled]; D.69510, *Sokol v. Pac. Teleph. & Teleg. Co.* (Aug. 3, 1965) 60 P.U.R.3d 427, 1965 WL 170980 [acknowledging that if a Commission "decision is invalid, so also may be every decision based on it."]) The Decision here carries out the retroactive implementation of the new methodology directed in the RA Decision, even though the Commission failed to justify that decision with adequate findings. Because the Decision carries out the RA Decision, and the RA Decision is not supported by adequate findings, the Decision cannot stand.

CONCLUSION

For the reasons stated above, CalCCA requests that the Court issue a writ of review, reverse the Decision, and grant the other requested relief.

DATED: July 17, 2026

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CERTIFICATE OF COMPLIANCE

Pursuant to California Rules of Court, rule 8.204, I hereby certify that the text of this Petition for Writ of Review contains 13,754 words, as determined by the word processing software used to prepare this brief and exclusive of this certification and the other exclusions referenced in Rule 8.204.

DATED: July 17, 2026

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PROOF OF SERVICE

California Community Choice Association v. California Public Utilities Commission et al.
In the Court of Appeal of the State of California Third District Court of Appeal

At the time of service, I was over 18 years of age and **not a party to this action**. I am employed in the County of San Francisco, State of California. My business address is 550 California Street, Suite 1200, San Francisco, CA 94104.

On July 17, 2026, I served true copies of the following document(s) described as:

PETITION FOR WRIT OF REVIEW; MEMORANDUM OF POINTS AND AUTHORITIES

APPENDIX OF EXHIBITS

on the interested parties in this action as follows:

SEE ATTACHED SERVICE LIST

BY PERSONAL SERVICE: I directed a process server to personally deliver the documents directly to the person(s) being served.

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I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on July 17, 2026, at San Francisco, California.

/s/ Frederick Ezekiel R. Pasco
Frederick Ezekiel R. Pasco

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In the Court of Appeal of the State of California Third District Court of Appeal

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IN THE MATTER OF: *2026 Integrated Energy Policy Report (IEPR) Update*	DOCKET NO. 26-IEPR-04 RE: Geothermal

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE IEPR COMMISSIONER TWO-DAY WORKSHOP ON CALIFORNIA'S GEOTHERMAL ENERGY RESOURCES

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CALIFORNIA ENERGY COMMISSION

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE IEPR COMMISSIONER TWO-DAY WORKSHOP ON CALIFORNIA'S GEOTHERMAL ENERGY RESOURCES

I. INTRODUCTION

The California Community Choice Association[1] (CalCCA) submits these comments on the June 19, 2026, and July 9, 2026, *IEPR Commissioner Two-Day Workshop on California's Geothermal Energy Resources*[2] (Workshop). California continues to make significant strides toward achieving the goals of Senate Bill (SB) 100,[3] which requires 100 percent of retail electricity sales to be supplied by renewable and zero-carbon resources by December 31, 2045. The Workshop highlighted that geothermal resources offer a promising opportunity to advance California toward achieving SB 100. As a clean firm resource, geothermal's consistent output

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[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] Docket No. 26-IEPR-04, *IEPR Commissioner Two-Day Workshop on California's Geothermal Energy Resources* (June 19, 2026 and July 9, 2026), https://www.energy.ca.gov/event/workshop/2026-06/iepr-commissioner-two-day-workshop-californias-geothermal-energy-resources and https://www.energy.ca.gov/event/workshop/2026-07/iepr-commissioner-two-day-workshop-californias-geothermal-energy-resources.

[3] SB 100 (De León, Chapter 312, Statutes of 2018), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

profile can support cost-effective decarbonization.[4] Community choice aggregators (CCAs) are committed to developing new resources to accelerate the state's clean energy buildout and support California's reliability goals,[5] and are actively exploring geothermal opportunities as a tool to accomplish these objectives.[6]

The Workshop also highlighted that geothermal resources face development challenges that the California agencies and stakeholders should seek to address. Given there is significant existing demand and interest in geothermal resources in California, state agencies should now focus on actions that will increase the availability of geothermal supply rather than imposing any additional geothermal-specific procurement mandates. These actions include looking at state-level barriers to resource development, such as financing challenges, specific permitting issues, and transmission infrastructure needs. Preserving procurement flexibility while supporting the

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4 *See, e.g.,* Long, J., E Baik, JD Jenkins, C Kolster, K Chawl, A Olson, A Cohen, M Colvin, S M Benson, RB Jackson, DG Victor, SP Hamburg, "California needs clean firm power, and so does the rest of the world: Three detailed models of the future of California's power system all show that California needs carbon-free electricity sources that don't depend on the weather" (2022), https://www.edf.org/sites/default/files/documents/SB100%20clean%20firm%20power%20report%20plus%20SI_clean.pdf.

5 As of November 19, 2025, California CCAs have secured more than 21 GW of new build clean energy resources through long-term PPAs, including 317 MW of geothermal, https://cal-cca.org/california-ccas-achieve-procurement-milestone-secure-21-gigawatts-of-new-build-clean-energy-resources/.

6 Clean Energy Alliance issued a Geothermal Energy Projects Request for Information in 2026 to "explore options to pursue next-generation geothermal projects that may not be construction-ready today" and "engage with geothermal energy developers, express interest in future/developing geothermal projects, and as a precursor to entering into future, bilateral offer discussions", https://thecleanenergyalliance.org/wp-content/uploads/2026/01/CEA-2026-RFI-for-Geothermal-Energy-Projects.pdf. Sonoma Clean Power is partnering with Sonoma and Mendocino counties and developers to develop 600 MW of next-generation geothermal energy: https://sonomacleanpower.org/geozone. California Community Power (CC Power) has executed Geothermal Exploration, Offtake and Development Engagement (GEODE) Agreements with three geothermal developers to encourage and support clean, firm geothermal generation capacity development in California, https://cacommunitypower.org/cc-power-signs-3-geode-agreements-to-incentivize-california-geothermal-development/.

development of supply will help avoid unintended pressure on the market that could increase prices, reduce competition, and jeopardize affordability, reliability, and clean energy objectives.

II. CCAS ARE ACTIVELY SEEKING TO ADD GEOTHERMAL TO THEIR PORTFOLIOS

CalCCA's members have been actively soliciting geothermal resources for several years to fulfill their clean energy needs in a reliable and affordable manner.[7] Their interest in geothermal stems primarily from its ability to provide clean energy in all hours, including those that are hard to decarbonize (*e.g.*, non-daylight hours). Based upon forecasts of geothermal costs and the assumption of resource availability, many CCAs have included geothermal resources in their Integrated Resource Plans (IRPs).

III. SEVERAL CHALLENGES AFFECT GEOTHERMAL DEVELOPMENT

Despite strong interest in developing geothermal resources, CCAs have had difficulty finding developers that are ready to commit to the investment needed to bring a geothermal plant to commercial operation.[8] There are several factors that may be contributing, including: (1) lack of commercial readiness; (2) lack of transmission and deliverability in viable locations; (3) licensing and permitting challenges; (4) development risks in new geothermal fields; and (5) political uncertainty.

The market is already taking steps to address these challenges. For example, in response to the lack of commercial readiness, several CCAs have begun working on pre-commercial

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7 CalCCA reviewed the websites of its members dating back to 2018 (with most between 2020 and present) and found 26 solicitations involving 15 CCAs (either jointly or individually) that conducted request for offers (RFO) seeking geothermal resources. In addition, many CCAs pursue direct bilateral negotiations with resources in addition to RFOs, which may well increase the number of CCAs soliciting geothermal.

8 The California Independent System Operator's (CAISO) interconnection queue currently only has two geothermal resources with capacity of just 62.435 megawatts. *See* CAISO, *Public Queue Report* (CAISO, July 20, 2026), https://www.caiso.com/library/public-queue-report.

agreements to continue progress necessary to develop geothermal and ultimately lead to commercial operation.[9] In addition, there are actions that state agencies can take to help encourage geothermal development by targeting barriers these resources face. These include permitting streamlining for resource confirmation activities, funding to derisk early project development investment and drive savings to ratepayers, and improvements to transmission planning to better align with the timelines, locations, and needs of these resources.

IV. CALIFORNIA SHOULD FOCUS ON SUPPORTING THE DEVELOPMENT OF SUPPLY RATHER THAN PRESCRIPTIVE TECHNOLOGY-SPECIFIC PROCUREMENT MANDATES

Because these challenges will take time to resolve, and because geothermal supply cannot expand immediately to meet California's growing demand, CCAs are concerned that regulatory procurement mandates may not reflect what is achievable in the market. Mandating procurement of specific resources and/or attributes possessed by only a specific type of resource is likely to place upward pressure on prices, increase compliance costs, and make it more difficult for LSEs to satisfy regulatory obligations.

Accordingly, California agencies should not adopt prescriptive geothermal—or other technology-specific—procurement requirements. Such mandates risk increasing costs, reducing procurement flexibility, and potentially undermining, rather than advancing, the State's affordability, reliability, and clean energy objectives. As shown above, demand for these resources already exists and is not the barrier slowing geothermal development. Instead, state agencies should focus their actions on supporting the supply of resources needed to advance

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9 For example, Clean Energy Alliance issued a Geothermal Energy Projects Request for Information in 2026 to "explore options to pursue next-generation geothermal projects that may not be construction-ready today" and "engage with geothermal energy developers, express interest in future/developing geothermal projects, and as a precursor to entering into future, bilateral offer discussions, https://thecleanenergyalliance.org/wp-content/uploads/2026/01/CEA-2026-RFI-for-Geothermal-Energy-Projects.pdf.

clean energy and reliability objectives through actions such as proactive transmission planning, limiting permitting delays/barriers, and other actions.

V. 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 to support geothermal development.

Respectfully submitted,

Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

July 23, 2026

Comments on Draft final proposal and stakeholder discussion for July 09, 2026

Initiative: Demand and distributed energy market integration

Comment period

Jul 09, 2026, 12:00 pm - Jul 23, 2026, 05:00 pm

Submitting organizations

California Community Choice Association

MCE

California Community Choice Association

Submitted on 07/29/2026, 02:11 pm

Contact

Shawn-Dai Linderman (shawndai@cal-cca.org)

1. Please provide your organization's feedback on the July 9, 2026 stakeholder meeting and the DDEMI Track 1: Draft Final Proposal – Reflecting End-User Exports in Demand Response paper.

The California Community Choice Association (CalCCA) appreciates the opportunity to provide comments on the Demand and Distributed Energy Market Integration (DDEMI) Track 1 Draft Final Proposal. CalCCA also appreciates the California Independent System Operator's (CAISO) detailed explanations regarding the eligibility for Net Energy Metering (NEM) and Net Billing Tariff (NBT) participation in the end-user export model, settlements, and non-responsive load, and reaffirms its support for the proposal. The proposal to recognize end-use customer exports while maintaining a resource-level export limit makes an important near-term incremental change to better leverage existing demand flexibility on the CAISO system. The CAISO should advance the proposal for implementation in 2027.

2. Please provide your organization's overall assessment of the Draft Final Proposal.

See responses in Sections 1, 5, and 7.

3. Does your organization support, support with caveats, oppose, or oppose with caveats the proposal? Please explain your rationale.

Support

For the reasons described in Section 1, above, CalCCA supports the proposal.

4. What revisions, if any, would your organization recommend before the proposal is finalized?

CalCCA has no proposed revisions at this time.

5. Please provide your organization's feedback on the proposal to recognize end-use customer exports while maintaining a resource-level export limit, including the discussion of market-wide and ISO balancing authority area (BAA) considerations.

The proposal to recognize end-use customer exports while maintaining a resource-level export limit makes an important near-term incremental change. The proposal will:

- Better leverage existing demand flexibility on the CAISO system;
- Minimize barriers to demand flexibility participation; and
- Expand the pool of dependable and price-responsive capacity on the CAISO system.

To further advance demand flexibility opportunities, the CAISO should facilitate discussions in future initiative tracks to remove barriers to exports beyond the resource level. While DR exports are supported through the Distributed Energy Resource Aggregation (DERA) model, there is currently no resource adequacy (RA) pathway for DERA resources, limiting their use. Future discussions in coordination with the California Public Utilities Commission (CPUC) should seek to remove barriers to exporting at the resource aggregation level, whether through future enhancements to the modified Proxy Demand Resource model or through the existing DERA model.

6. Please provide your organization's feedback on the proposed settlement framework, including the hierarchical baseline adjustment factor methodology.

CalCCA generally supports the CAISO's proposed hierarchical baseline adjustment factor methodology. This proposal was first introduced in the Draft Final Proposal. Upon initial review, CalCCA has identified some potential methodological changes that could improve the accuracy of the adjustment factor. To ensure all parties have a common understanding of the current methodology, the CAISO should clarify that the adjustment factor is currently calculated by taking the ratio of the sum of net load over all settlement intervals on the event day and the sum of net load over all settlement intervals in the historical baseline period. Building upon this clarification, CalCCA recommends two refinements to the proposed hierarchical baseline adjustment factor methodology.

First, the CAISO should ensure the proposed hierarchical methodology is applied consistently. Specifically, the CAISO should consider the mathematical validity of the adjustment factor produced using the existing methodology (Step 1) before moving to excluding export intervals (Step 2). Examples C and D in the proposal illustrate this inconsistency in applying the CAISO's proposed methodology.

- In Example C (p. 32), applying the existing methodology produces a mathematically valid adjustment factor. However, it appears the CAISO unnecessarily excludes the export interval, resulting in a lower adjustment factor than if the existing methodology were applied.

  <u>CAISO's Example C calculation</u>:
  Adjustment Factor = (50 + 66) ÷ (40 + 60) = 116 ÷ 100 = 1.16

Calculation using existing methodology:
Adjustment Factor = (-15 + 50 + 66) ÷ (-20 + 40 + 60) = 101 ÷ 80 = 1.26 (capped at 1.20)

Excluding the export interval results in an artificially lower adjustment factor, resulting in an inaccurate adjustment to the customer's historical event baseline.

• In Example D (p. 33), applying the existing methodology also produces a mathematically valid adjustment factor. However, it appears the CAISO unnecessarily excludes all export intervals, resulting in no remaining valid data. CAISO then jumps to Step 3 and applies an adjustment factor of 1.0.

CAISO's Example D calculation:
Exclude all export intervals and apply an adjustment factor of 1.0

Calculation using existing methodology:
Adjustment Factor = (-15 + (-25) + (-10)) ÷ (-10 + (-20) + (-5)) = (-50) ÷ (-35) = 1.43 (capped at 1.20)

This is a mathematically valid result, as applying a 1.20 adjustment factor would indicate increased exports on the event day, which is representative of actual customer behavior on the event day. Applying an assumed factor of 1.0 produces in a higher historical event baseline (lower exports), resulting in overcompensation of the customer's event day response.

Second, the CAISO should consider changes to the proposed hierarchical baseline adjustment factor methodology to allow for more export intervals to be included, to ensure accurate compensation of customer response. Specifically, the CAISO could add the following step to the hierarchical approach, sequenced after the existing proposed Step 1:

• If applying the existing methodology (Step 1) results in a negative or 0 adjustment factor, indicating that customer load is swinging from negative (exporting) to positive (importing), or vice versa, between the historical baseline and the event day net load, then default to the minimum adjustment factor (0.80) instead of excluding settlement intervals with exports from the calculation. This would be more aligned with the existing methodology – i.e., if there is a drastic change in load between the historical baseline and event day behavior, then the adjustment factor is capped at 20 percent up or down.

Example	Average Historical Baseline Net Load (kW)	Average Event Day Net Load (kW)
Example 1: Export to Import swing	-20	30
Example 2: Import to Export swing	30	-20
Example 3: Export to 0 net load swing	-20	0

In these examples, applying the existing methodology (Step 1) would result in a negative adjustment factor, which is mathematically invalid. However, if the sign of the load flips, we know that the customer's event day net load is at least 100 percent lower or higher than their historical baseline net load. Thus, we can apply the capped downward adjustment factor of 0.80, which would move the customer's historical event baseline closer to 0, accurately reflecting their event day behavior.

- In Example 1, if the customer’s historical event baseline is -200 kWh, then the adjusted baseline would be:
  -200 kWh x 0.80 = -160 kWh

  This result accurately reflects lower exports (or higher imports) on the event day.

- In Example 2, if the customer’s historical event baseline is 300 kWh, then the adjusted baseline would be:
  300 kWh x 0.80 = 240 kWh

  This result accurately reflects lower imports (or higher exports) on the event day.

- In Example 3, if the customer’s historical event baseline is -200 kWh, then the adjusted baseline would be:
  -200 kWh x 0.80 = -160 kWh

  This result accurately reflects lower exports (or higher imports) on the event day.

With this additional step in the methodology, excluding export intervals and defaulting to a factor of 1.0 would only be necessary if the existing methodology results in an undefined adjustment factor due to dividing by 0.

7. Please provide your organization's feedback on the ISO's proposal to maintain eligibility for Net Energy Metering (NEM) and Net Billing Tariff (NBT) customers, including the rationale for distinguishing retail export compensation from wholesale demand response compensation.

CalCCA agrees with the CAISO that retail export compensation and wholesale DR compensation are distinct services and supports maintaining the eligibility of NEM and NBT customers.

8. Please provide your organization's feedback on the ISO's discussion of non-responsive load.

CalCCA agrees with the CAISO’s determination that the proposed construct only compensates for demonstrated performance, and that by definition, non-responsive load does not perform and is therefore not compensated. Changes to the proposal related to non-responsive load are therefore unnecessary.

9. Please provide any additional comments, implementation considerations, examples, or recommendations.

CalCCA has no additional comments at this time.

MCE

Submitted on 07/23/2026, 03:30 pm

Contact

Jordyn Bishop (jbishop@mceCleanEnergy.org)

1. Please provide your organization's feedback on the July 9, 2026 stakeholder meeting and the DDEMI Track 1: Draft Final Proposal – Reflecting End-User Exports in Demand Response paper.

MCE appreciates the opportunity to submit these comments on the July 9, 2026 stakeholder meeting and the DDEMI Track 1: Draft Final Proposal – Reflecting End-User Exports in Demand Response paper. MCE supports the Track 1: Draft Final Proposal.

2. Please provide your organization's overall assessment of the Draft Final Proposal.

MCE supports the Track 1: Draft Final Proposal. MCE appreciates the additional clarity provided in this version regarding deliverability, interconnection, settlement, and implementation responsibilities.

3. Does your organization support, support with caveats, oppose, or oppose with caveats the proposal? Please explain your rationale.

Support

MCE supports the Track 1: Draft Final Proposal. The proposal addresses a critical limitation of the current demand response participation models by allowing demand response providers and the CAISO to capture the additional export capacity that already exists, while maintaining wholesale demand response as a load curtailment product at the resource level.

4. What revisions, if any, would your organization recommend before the proposal is finalized?

MCE has no comments at this time.

5. Please provide your organization's feedback on the proposal to recognize end-use customer exports while maintaining a resource-level export limit, including the discussion of market-wide and ISO balancing authority area (BAA) considerations.

MCE supports the incremental reforms of the Track 1: Draft Final Proposal, and appreciates the CAISO's inclusion of market-wide and ISO balancing authority area considerations in this version. MCE supports advancing the Track 1: Draft Final Proposal now, and addressing net exports beyond the resource-level in a future phase of DDEMI.

6. Please provide your organization's feedback on the proposed settlement framework, including the hierarchical baseline adjustment factor methodology.

MCE supports the proposed settlement framework, including the hierarchical baseline adjustment factor methodology.

7. Please provide your organization's feedback on the ISO's proposal to maintain eligibility for Net Energy Metering (NEM) and Net Billing Tariff (NBT) customers, including the rationale

for distinguishing retail export compensation from wholesale demand response compensation.

MCE has no comments at this time.

8. Please provide your organization's feedback on the ISO's discussion of non-responsive load.

MCE has no comments at this time.

9. Please provide any additional comments, implementation considerations, examples, or recommendations.

MCE has no additional comments at this time.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Improve the California Climate Credit.	R.25-07-013

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ASSIGNED COMMISSIONER'S RULING PROVIDING DIRECTION AND SETTING THE PHASE 1B PROCEDURAL SCHEDULE

Leanne Bober,
Director of Regulatory Affairs and
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July 24, 2026

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS[1]

The Commission should:

- Evaluate any proposed changes to the current Climate Credit distribution structure pursuant to the Guidance Ruling priorities of affordability, simplicity, fairness, electrification, and a narrow focus, recognizing that beneficial electrification—not electricity usage alone—and overall net customer benefit;

- Include LSE competitive neutrality as an express Assigned Commissioner priority, consistent with CARB regulations and the Commission's longstanding implementation of the Climate Credit, to ensure equivalent treatment of bundled and unbundled customers across LSEs;

- Retain the existing equal, non-volumetric electric Climate Credit methodology because it provides broad, predictable bill relief, minimizes implementation costs, and maximizes the value returned to customers;

- If the Commission nevertheless moves forward with changes to the distribution methodology, it should, above all, avoid reducing benefits for low-income customers and, where supported by the record, prioritize providing additional benefits to CARE customers while preserving a meaningful Climate Credit for all residential customers;

- Require that any proposal departing from the status quo demonstrate that its incremental customer benefits materially outweigh its additional costs, complexity, and implementation risks;

- Require that any party proposal provide sufficient legal, policy, implementation, cost, and customer-impact information to enable meaningful evaluation and comparison against the existing methodology;

- Require robust implementation review and post-implementation reporting for any new methodology, including implementation costs, customer impacts, customer understanding, and a formal reevaluation if the methodology does not perform as intended; and

- Limit changes to the natural gas Climate Credit to those necessary to comply with CARB regulations while monitoring affordability, electrification, customer bill impacts, and the transition from natural gas to electricity to inform future Commission action.

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[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 Improve the California Climate Credit.	R.25-07-013

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ASSIGNED COMMISSIONER'S RULING PROVIDING DIRECTION AND SETTING THE PHASE 1B PROCEDURAL SCHEDULE

California Community Choice Association[2] (CalCCA) submits these opening comments pursuant to the *Assigned Commissioner's Ruling Providing Direction and Setting the Phase 1B Procedural Schedule*[3] (Guidance Ruling), dated June 29, 2026. The subsequent July 9, 2026, Administrative Law Judge *Email Ruling Adjusting the Procedural Schedule*[4] adjusted other procedural deadlines, including the timing of small and multi-jurisdictional utilities data filings and Reply Comments, but did not affect the July 24, 2026, deadline for these Opening Comments.

I. INTRODUCTION

This Climate Credit proceeding began against the backdrop of California's continuing affordability crisis. Governor Gavin Newsom's Executive Order N-5-24 directed the California Air Resources Board (CARB) and the California Public Utilities Commission (Commission) to

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[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] *Assigned Commissioner's Ruling Providing Direction and Setting the Phase 1B Procedural Schedule*, Rulemaking (R.) 25-07-013 (June 29, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M609/K606/609606098.PDF.

[4] *Email Ruling Adjusting the Procedural Schedule*, R.25-07-013 (July 9, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M610/K354/610354084.PDF.

evaluate how the Climate Credit can most effectively support Californians during the state's clean-energy transition.[5] The Commission subsequently opened this proceeding to "consider ways to improve the effectiveness of the California Climate Credit for supporting customer affordability…."[6] After the proceeding commenced, the Legislature enacted Assembly Bill (AB) 1207, directing the Commission to "maximize customer electric bill affordability" by providing the Climate Credit in no more than four high-billed months each year.[7] Phase 1A implemented that directive by shifting the timing of the residential electric Climate Credit from April and October to August and September in an effort to address the majority of residential customers' high-billed months.[8] Phase 1B now asks the broader question of whether changes to the methodology used to calculate and distribute the Climate Credit are warranted.[9]

The Assigned Commissioner's Guidance Ruling identifies affordability as the central priority of this Phase 1B, while also emphasizing fairness, simplicity, electrification, and maintaining a narrow focus.[10] CalCCA supports each of these priorities. The question before the Commission is, therefore, not whether the Climate Credit should continue to promote affordability, but how to maximize the affordability impacts among Californians.

The Climate Credit occupies a unique place within California's affordability framework. Unlike California Alternate Rates for Energy (CARE), Family Electric Rate Assistance (FERA),

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5 Executive Order N-5-24, at 1-2 and Ordering Paragraph 4 (Oct. 30, 2024), https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf.

6 *Order Instituting Rulemaking to Improve the California Climate Credit*, R.25-07-013 (July 28, 2025) at 1, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M574/K655/574655670.PDF.

7 Assembly Bill No. 1207, Ch. 117, Stats. 2025 (Sept. 19, 2025), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202520260AB1207.

8 D.26-04-036, *Decision Ordering Immediate Improvements to the California Climate Credit to Lower Electric and Gas Bills,* R.25-07-013 (May 1, 2026), at 2, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M605/K990/605990203.PDF.

9 Guidance Ruling, at 1-2.

10 *Id*. at 3-5.

and other targeted assistance programs, the Climate Credit provides meaningful bill relief to virtually every eligible residential customer. Many Californians struggling to pay their electric bills do not qualify for income-based assistance programs, are not enrolled in those programs, or otherwise fall outside their eligibility requirements despite experiencing genuine affordability challenges. The Climate Credit complements those targeted programs by providing broad, visible, and predictable relief to all residential customers. Rather than viewing that universal character as a weakness to be corrected, the Commission should recognize it as one of the Climate Credit's greatest strengths and preserve that value as it considers potential reforms.

This approach is fully consistent with AB 1207, which directs the Commission to maximize the affordability benefit of the Climate Credit, while providing discretion to the Commission to determine how best to accomplish that objective.[11] As the Legislative Analyst's Office (LAO) observed, AB 1207 does not prescribe whether the electric Climate Credit should be universal or targeted, fixed or volumetric, or differentiated by geography or income.[12] At the same time, the LAO also recognized that the statute provides little direction regarding the scope of any redesign beyond providing the credits in no more than four high-billed months each year.[13] In light of that limited statutory direction, the LAO questions whether the Legislature intended the Commission to undertake more complex policy changes, particularly given the funding requested by the Commission to do so and the tradeoffs such changes may entail.[14]

Thus, the Commission need not conclude that maximizing affordability requires a more complex methodology than the status quo of distributing the Climate Credit to all customers.

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11 AB 1207 (amending Public Utilities Code § 748.5(a)(3)).

12 Legislative Analyst's Office, *The 2026-27 Budget: California Public Utilities Commission's Implementation of AB 1207* (Feb. 10, 2026) (LAO Report), https://lao.ca.gov/Publications/Report/5120.

13 *Ibid*.

14 *Ibid*.

Rather, at present, maximizing affordability is best achieved by preserving the full value of a simple, broadly distributed Climate Credit and delivering that credit during the months the Commission has already determined is consistent with AB 1207.

CalCCA therefore provides the following overarching comments in response to the Guidance Ruling. *First*, the Guidance Ruling's stated priorities provide a good framework for evaluating proposals. However, the longstanding principle of competitive neutrality among load-serving entities should be added to ensure equivalent treatment of all customers. *Second*, the existing equal, non-volumetric Climate Credit remains the methodology best supported by the present record because it most effectively advances affordability, simplicity, fairness, and overall customer benefit while minimizing unnecessary implementation costs and customer confusion. *Third*, if the Commission nevertheless moves forward with changes to the distribution methodology, it should ensure that no low-income customer is made worse off than under the status quo and should prioritize providing additional benefits through a simple CARE adder while preserving a meaningful Climate Credit for every residential customer.

Based on these overarching themes, CalCCA recommends that the Commission:

- Evaluate any proposed changes to the current Climate Credit distribution structure pursuant to the Guidance Ruling priorities of affordability, simplicity, fairness, electrification, and a narrow focus, recognizing that beneficial electrification—not electricity usage alone—and overall net customer benefit;
- Include load-serving entity (LSE) competitive neutrality as an express Assigned Commissioner priority, consistent with CARB regulations and the Commission's longstanding implementation of the Climate Credit, to ensure equivalent treatment of bundled and unbundled customers across LSEs;
- Retain the existing equal, non-volumetric electric Climate Credit methodology because it provides broad, predictable bill relief, minimizes implementation costs, and maximizes the value returned to customers;
- If the Commission nevertheless moves forward with changes to the distribution methodology, it should, above all, avoid reducing benefits for low-income customers and, where supported by the record, prioritize providing additional benefits to CARE customers while preserving a meaningful Climate Credit for all residential customers;

- Require that any proposal departing from the status quo demonstrate that its incremental customer benefits materially outweigh its additional costs, complexity, and implementation risks;
- Require that any party proposal provide sufficient legal, policy, implementation, cost, and customer-impact information to enable meaningful evaluation and comparison against the existing methodology;
- Require robust implementation review and post-implementation reporting for any new methodology, including implementation costs, customer impacts, customer understanding, and a formal reevaluation if the methodology does not perform as intended; and
- Limit changes to the natural gas Climate Credit to those necessary to comply with CARB regulations while monitoring affordability, electrification, customer bill impacts, and the transition from natural gas to electricity to inform future Commission action.

II. THE GUIDANCE RULING PRIORITIES SHOULD BE ADOPTED, WITH THE ADDITION OF LSE COMPETITIVE NEUTRALITY

The Assigned Commissioner identifies five priorities to guide this phase of the proceeding: affordability, electrification, fairness, simplicity, and maintaining a narrow focus.[15] CalCCA agrees that each of these priorities should be adopted and explains below how those priorities should be applied in light of the Commission's longstanding Climate Credit policies, the CARB regulations, and the current evidentiary record. CalCCA also emphasizes that fairness should include the related principle of LSE competitive neutrality, which should also be expressly adopted as a priority for this proceeding. The following addresses how each of the priorities, as well as competitive neutrality, should be applied in this proceeding.

A. Affordability: The Climate Credit Should be Preserved as a Universal Source of Bill Relief

Affordability is appropriately the central objective of this proceeding. The Climate Credit is uniquely positioned to advance affordability because it provides meaningful bill relief to every eligible residential customer. Unlike targeted affordability programs such as CARE and FERA,

15 Guidance Ruling, at 3-5.

the Climate Credit reaches customers across the income spectrum, including many households experiencing genuine affordability challenges, especially those that fall just outside the qualifying range for existing assistance programs. Preserving that universal benefit is itself an important component of fairness, considering all residential customers bear the costs of California's Cap-and-Invest Program through their electricity rates.[16] Any proposal that narrows eligibility or substantially redistributes benefits should therefore demonstrate that it produces materially greater net customer benefits than the existing methodology, which allocates the Climate Credit to all customers equally.

Any redistribution of the Climate Credit, by its very nature as a finite amount of bill relief, creates winners and losers. Increasing the Climate Credit for one set of ratepayers will be offset by decreasing the Climate Credit for another set of ratepayers. Minimizing the negative offsetting impacts, especially for low-income customers, is critical in maintaining affordability as a central principle. Thus, as further explained below, any proposal that is considered should, above all, ensure that low-income customers are not worse off than they are under the current methodology.

B. Simplicity: The Climate Credit Should be Understandable and Administratively Workable

Simplicity in distribution of the Climate Credit should remain one of the Commission's highest priorities. *First*, customers should reasonably understand whether they will receive the Climate Credit, approximately how much they should expect to receive, and why they received that amount. If multiple customers in the same area receive materially different electricity bill

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16 CARB, *Electrical Distribution Utility and Natural Gas Supplier Allowance Allocation* ("For investor-owned utility ratepayers, all Cap-and-Trade Program costs are passed through in electricity rates, and proceeds from the auction of allocated allowances are used to benefit ratepayers."), https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/allowance-allocation/edu-ngs.

relief from the Climate Credit, what is intended to be solely a positive affordability outcome for customers could also be met with confusion and potential frustration. *Second*, a simple program maximizes value to customers by ensuring implementation costs do not necessarily reduce the amount of allowance revenues ultimately returned to customers. Simplicity, therefore, advances affordability, customer confidence, and efficient administration alike. As the Guidance Ruling recognizes, the Commission should not "overextend ourselves with complicated approaches whose costs outweigh the customer benefit."[17]

C. Fairness and Competitive Neutrality: Customer Benefits Should be Fair and Bundled or Unbundled Status Should Not Impact Climate Credit Eligibility

Fairness should extend beyond the allocation of Climate Credit revenues to encompass how the program operates for customers and load-serving entities. The Commission has long recognized that Climate Credit implementation should remain competitively neutral, and CARB's regulations continue to require equivalent treatment for bundled and unbundled residential customers.[18] Likewise, customers similarly situated with respect to the Climate Credit should receive comparable treatment regardless of generation provider.

The Commission should also evaluate proposals based on the net customer benefit ultimately delivered—not simply how Climate Credit revenues are redistributed. Climate Credit revenues are finite. Every additional dollar devoted to billing system modifications, implementation, administration, or customer outreach is a dollar unavailable for direct customer bill relief. Complexity, therefore, is not merely an implementation concern—it is itself a fairness concern. A proposal that marginally improves the redistribution of benefits but substantially

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[17] Guidance Ruling, at 4.

[18] 17 CCR § 95892(d)(6); D.12-12-003, at 67.

increases implementation costs may ultimately reduce the overall affordability benefit provided to California customers.

D. Electrification: The Climate Credit Distribution Framework Should Support Beneficial and Efficient Electrification

CalCCA supports the Commission's interest in aligning the Climate Credit with California's broader electrification goals where appropriate. However, the Climate Credit should encourage beneficial and efficient electrification rather than simply rewarding higher electricity consumption as would an increased benefit for usage above a baseline allowance or through a purely volumetric credit. Increased electricity usage alone does not necessarily equate to progress toward electrification or improved affordability. Electricity consumption reflects numerous factors, including climate, household size, housing characteristics, energy efficiency, medical needs, rooftop solar, conservation behavior, and discretionary usage. Likewise, lower electricity usage does not necessarily indicate lesser need or a lack of electrification.

The current record also does not yet demonstrate that electricity usage, baseline allowances, or climate zones are reliable means of distinguishing customers who have undertaken beneficial electrification from those whose higher consumption reflects other factors. Nor does the record currently provide evidence of a methodology for redistribution of the Climate Credit that would incentivize beneficial electrification. A methodology that primarily rewards higher usage risks creating incentives that are inconsistent with California's broader efficiency and conservation objectives[19] while providing additional benefits to customers whose usage is unrelated to electrification.

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[19] *See* Pub. Resources Code § 25310(c)(1) (requiring annual statewide energy efficiency savings and demand reduction targets that achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by Jan. 1, 2030), as added by Senate Bill No.

Accordingly, before replacing a universally distributed credit with one based upon electricity usage or similar proxies, the Commission should have confidence that the alternative materially improves affordability and supports beneficial electrification after accounting for implementation costs, customer understanding, and impacts on vulnerable households. To the extent the Commission seeks to encourage long-term electrification investments, other proceedings and rate design options are likely better suited to provide the sustained price signals necessary to influence those decisions.

E. Narrow Focus: The Climate Credit's Distinct Role Should be Preserved

Finally, CalCCA agrees that this phase should maintain a relatively narrow focus. The Climate Credit is an essential affordability tool, but it should not become the mechanism for addressing every affordability, rate design, or electrification policy objective facing California. Other Commission proceedings, including the California Advanced Electric Rate Design proceeding (R.26-04-009), are already examining residential rate design, baseline allowances, affordability, efficient price signals, electrification, and the interaction between CARE, the Base Services Charge, and other affordability programs. Other proceedings therefore incorporate broader Commission authority and allow more developed records to address these structural policy questions. This proceeding should instead preserve what makes the Climate Credit uniquely valuable: providing broad, visible, predictable, and readily understandable bill relief to residential customers while allowing complementary proceedings to address broader affordability reforms.

350, Ch. 547, Stats. 2015 (Oct. 7, 2015), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

These principles are also consistent with the Commission's longstanding approach to the Climate Credit. Decisions (D.)12-12-033[20] and 21-08-026[21] emphasized a Climate Credit that is understandable to customers, administratively practical, broadly available, and competitively neutral. The Guidance Ruling's priorities, with the addition of LSE competitive neutrality, therefore, build naturally upon those longstanding principles by placing additional emphasis on affordability. CalCCA's recommendations below seek to achieve these objectives by preserving the Climate Credit's unique role while ensuring that any reforms produce meaningful net customer benefits and, above all, avoid disadvantaging low-income customers.

III. THE EXISTING CLIMATE CREDIT DISTRIBUTION FRAMEWORK SHOULD BE MAINTAINED, AS IT ACCOMPLISHES THE STATUTORY AND GUIDANCE RULING PRIORITIES

Applying these principles, CalCCA preliminarily concludes that the existing equal, non-volumetric electric Climate Credit methodology –distributed during the August and September billing cycles consistent with the Commission's Phase 1A decision– likely remains the approach best supported by the current record. This approach preserves universal affordability, remains simple and neutral to administer, avoids reducing the benefit for any low-income customers, maximizes the amount of allowance revenues ultimately returned to customers, avoids relying on imperfect proxies for financial need, and preserves the Climate Credit's distinct role while allowing other Commission proceedings to address broader affordability and rate design issues. CalCCA reserves the right to modify this preferred method as the proceeding develops.

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20 D.12-12-033, *Decision Adopting Cap-and-Trade Greenhouse Gas Allowance Revenue Allocation Methodology for the Investor-Owned Electric Utilities*, R.11-03-012 (Dec. 20, 2012), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M040/K631/40631611.PDF.

21 D.21-08-026, *Decision Adopting Customer Climate Credit Updates*, R.20-05-002 (Aug. 19, 2021), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M402/K296/402296732.PDF.

IV. ANY ALTERNATIVE CLIMATE CREDIT DISTRIBUTION FRAMEWORK SHOULD PROVIDE ADDITIONAL BENEFITS TO CARE CUSTOMERS WHILE PRESERVING A MEANINGFUL CLIMATE CREDIT FOR ALL RESIDENTIAL CUSTOMERS

If the Commission nevertheless moves forward with changes to the distribution methodology of Climate Credit benefits, CalCCA preliminarily supports providing additional benefits to CARE customers while preserving a meaningful Climate Credit for all residential customers. Such a concept could take the form of simply providing a Climate Credit multiplier for CARE customers. CARE represents an existing, readily understandable, and administratively efficient indicator of financial need that is more directly tied to affordability than electricity usage or geography. Even this alternative, however, should be evaluated only after parties have had an opportunity to review the utility data required by the Guidance Ruling and the implementation cost and feasibility analyses submitted with the utilities' Opening Comments. Accordingly, CalCCA reserves the right to refine its position as the record develops.

V. CALCCA'S RESPONSES TO SECTION 4 OF THE RULING: GUIDANCE RULING QUESTIONS FOR PARTY COMMENT

4.1. Overarching Legal and Authority Questions

1. **What limitations from CARB regulations, as adopted by CARB on May 29, 2026 apply to changes made in this phase?**

CalCCA has not identified a CARB limitation that requires a change to the existing electric Climate Credit methodology or prohibits the Commission from retaining the status quo. Any electric-credit proposal must, however, remain consistent with the applicable requirements governing the use and return of allowance value. Of particular importance here, section 95892(d)(6) of the CARB regulations provides: "Investor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers and community choice aggregators." Thus, any changes to the Climate Credit outside of the status quo, must satisfy this regulation and support CalCCA's proposed overarching principle of competitive neutrality.

2. **CARB separately adopted Resolution 26-7 on May 29. The last two resolutions on page 17 direct CARB staff to:**

    a. **Coordinate with the Commission regarding natural gas transition issues; and**

    b. **Consult with the Commission on Diablo Canyon allocation issues.**

    Do either of these resolutions impact considerations in this phase?

The two directives do not appear to materially affect the issues being decided in Phase 1B. CARB's direction to coordinate with the Commission regarding natural gas transition issues is consistent with implementation of the updated CARB regulations, but it does not appear to require a broader redesign of the residential natural gas Climate Credit in this Phase. Rather, it reinforces the need for continued interagency coordination as California implements the longer-term transition away from natural gas. CARB's direction to consult with the Commission regarding Diablo Canyon allocation issues concerns a separate allowance allocation question and does not appear to dictate any particular methodology for distributing the residential electric Climate Credit. Nothing in the resolution suggests that Diablo Canyon-related allocation decisions should influence how the residential Climate Credit is distributed.

3. **What limitations, if any, from Pub. Util. Code Section 748.5, and/or any other section, apply to considerations in this phase?**

Public Utilities Code section 748.5 establishes important parameters for the Climate Credit's purpose, timing, and communication. Section 748.5(a)(3) directs the Commission to determine how to provide the residential credit in no more than four high-billed months, with the goal of maximizing customer electric-bill affordability while considering months with high electricity bills.[22] The statute thus treats the Climate Credit primarily as concentrated bill relief,

[22] Cal. Pub. Util. Code § 748.5(a)(3); *see also* Guidance Ruling, at 10-11.

not as a continuous marginal price signal. This statutory structure also suggests that the Legislature viewed the Climate Credit primarily as an affordability tool rather than as a long-term behavioral incentive. Section 748.5(a)(3) may also restrict the Commission from action other than moving the credit within those four high-billed months absent a showing of "extreme, unforeseen, and temporary circumstances."[23]

Section 748.5 does not require the Commission to adopt a usage-based methodology. Nor does it require redistribution based on baseline usage, climate zone, or income. The Commission retains discretion to preserve an equal credit if that approach best balances affordability, fairness, low-income impacts, simplicity, and cost. Section 748.5's emphasis on maximizing affordability also requires consideration of net benefits. A nominal improvement in redistributing does not maximize affordability if implementation and administrative costs materially reduce the proceeds returned to customers.

Section 748.5(b)(2) also requires specified information concerning the Climate Credit to be displayed prominently on customer bills.[24] While customer outreach and messaging has been deferred to a later portion of Phase 1B, any methodology that produces differing or uncertain amounts will make that communication more difficult. The Commission should therefore consider now whether a proposal can be explained accurately and neutrally in a short bill message.

Finally, in addition to the Commission's prior recognition of competitive neutrality as a high priority Climate Credit policy objective,[25] CARB section 95892(d)(6) requires IOUs to ensure equal treatment of their own customers and customers of electricity service providers and CCAs.[26]

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23 Cal. Pub. Util. Code § 748.5(a)(3)
24 Cal. Pub. Util. Code § 748.5(b)(2).
25 D.12-12-003, at 67.
26 17 CCR § 95892(d)(6).

4. **Are there any other specific authorities that apply to and should guide other changes made in this Phase?**

CalCCA has no comment at this time.

4.2. Guiding Principles

1. **When considering changes to the Climate Credit, should the Commission consider any other factors besides:**
   a. **Laws, regulations, and legislative intent;**
   b. **Guiding principles;**
   c. **Customer characteristics and impacts on customers;**
   d. **Implementation feasibility, time, and cost?**

No, but the Commission should emphasize guiding principles such as customer understanding, predictability, net customer benefit, avoiding negative impacts on low-income and disadvantaged customers, and competitive neutrality.

First, a customer should be able to understand why the credit was received and how its amount was determined. A methodology that produces substantially different credits for neighbors, or different outcomes across LSEs, may be technically explainable yet remain confusing in practice. Simplicity should be evaluated from the customer's perspective, not solely by whether it is ultimately feasible.

Second, predictability matters. Customers should know when the credit will arrive and, to the extent practicable, its amount. The Guidance Ruling recognizes this by favoring retention of an amount approved in advance and consistent timing.[27] A predictable flat credit is especially valuable to households managing limited cash flow.

Third, implementation costs should be measured against the incremental benefit of the change. The proper comparison is not whether a proposal can be implemented, but whether its

[27] Guidance Ruling, at 4.

additional redistributed benefit exceeds the full cost of billing changes, testing, administration, oversight, customer service, and outreach. Proposals that fail that test should not proceed.

Fourth, if the Commission considers redistributing the Climate Credit based on certain customer characteristics, it should ensure that no low-income customer is made worse off than under the current methodology. Any redistribution will inevitably create winners and losers. The Commission should not increase benefits for one group of customers by reducing benefits for those least able to absorb the loss. For example, reducing the Climate Credit for a low-income customers in a cooler climate to increase the Climate Credit for higher-income customer in a hotter climate would be inconsistent with the Commission's affordability objective. Moreover, affordability cannot be evaluated based on electricity usage or climate alone. California households face a range of cost pressures, and any redesign should avoid relying on proxies that inadvertently disadvantage financially vulnerable customers.

Fifth, the Commission should assess whether the proposal is neutral among customers served by different LSEs. While the Commission should strive to avoid winners and losers amongst customers, it must ensure that there are no winners and losers amongst LSEs.

2. **How should affordability metrics from the Affordability Rulemaking (R.18-07-006) be integrated or considered in this proceeding?**

If the Commission considers a redistribution beyond the methodology adopted in D.26-04-036, it should use the Affordability Rulemaking's affordability metrics to evaluate whether a proposal reduces or increases burdens for customers in areas of affordability concern and for vulnerable households that may not be enrolled in CARE.

That analysis is important because CARE status, usage, climate zone, and affordability are related but not interchangeable. Some financially vulnerable customers are not enrolled in CARE, and some CARE customers may use less than the baseline because they cannot afford additional consumption, they are additionally vulnerable due to other costs of living, or they are in smaller residences with inherently smaller electricity bills. A baseline or volumetric approach could therefore reduce assistance to customers with the greatest need unless the data demonstrates otherwise. Thus, if the Commission decides to move beyond the status quo, the Commission's affordability metrics can provide an additional check to ensure additional benefits are received by those most in need.

3. **Which specific principles established by D.12-12-033 and updated by D.21-08-026 (for the electric credit) and D.15-10-032 (for the gas credit) should be modified?**

CalCCA strongly emphasizes maintaining competitive neutrality, which was a high priority in the last two electric credit decisions but was not listed in the Guidance Ruling's priorities. The Commission should continue to prioritize both administrative simplicity and customer comprehension, recognizing that a methodology customers cannot readily understand ultimately undermines the value of the Climate Credit itself.

4.3. Assigned Commissioner's Priorities

1. **Do you agree with the assigned Commissioner's priorities as laid out in Section 2 of this ruling? Do you recommend changes or additions to this list?**

Yes, with the addition of LSE competitive neutrality. See Section II., above.

4.4. Narrow Focus on Three Options

1. **Section 2.4 of this ruling provides three options as the procedural focus of this phase: the status quo, the assigned commissioner's proposals, and party proposals. Are these options reasonable? Is a narrow focus appropriate?**

A narrow focus is appropriate given the schedule, the need for understandable customer outcomes, and the cost of implementing billing changes. The status quo should serve as the benchmark against which every alternative is evaluated.

The record should compare potential alternatives using the same criteria. For example: (1) total and per-customer implementation cost; (2) implementation time; (3) net amounts returned to customers; (4) impacts on CARE and other vulnerable customers; (5) impacts on customers who have adopted efficiency upgrades; (6) predictability and ease of explanation; (7) consistency across utilities and load-serving entities; and (8) the likelihood of creating inefficient consumption incentives. An alternative should displace the status quo only if it produces a clear, material, and durable improvement across a range of criteria.

CalCCA understands that some of this data is included in the utility responses to the Guidance Ruling's data requests and is continuing to review those responses. Should the Commission choose to further refine the initial proposals, a standardized way of reviewing the proposals against the status quo benchmark would provide parties with an opportunity to easily understand support for those variations.

2. **Option 1 in Section 2.4 is to retain the Climate Credit status quo, possibly with minor modifications (such as changing the number of distributions or adjusting timing but without changes to calculation methodology). Does this option satisfy legal requirements and principles? What modifications should be made, if any, if the Commission adopts this option? Which ideas raised by parties in Phase 1A are appropriate for consideration here?**

Yes. Retaining the equal, non-volumetric credit satisfies the applicable legal requirements and balances the competing principles on the current record. It ensures that all eligible residential customers receive relief; avoids using imperfect proxies for need; preserves a predictable and understandable benefit; and minimizes implementation cost and risk.

CalCCA does not recommend modifying the distribution methodology at this time. The Commission has already adjusted distribution timing through D.26-04-036 to provide relief during the periods it identified as high-bill months. Further refinement should be limited and supported by evidence that any benefits and upsides exceed the costs and downsides and do not generate additional customer confusion.

If the Commission concludes that some redistribution is necessary, the preferable direction is a simple CARE adder while retaining a meaningful base credit for every residential customer. This would most likely provide additional benefit to low-income households without creating classes of winners and losers. However, the amount of any adder, its distributional effects, and its administrative feasibility would need refinement and should be subject to additional data requests and review. Accordingly, CalCCA reserves the right to refine its position as the record develops.

3. **The schedule includes a ruling to provide direction for proposals. What direction, criteria and rules should apply to party proposals? What detail should be required (in party proposals and the assigned commissioners') to ensure that the utilities can provide implementation assessments and parties can fully consider them?**

The Commission should evaluate any party's proposed changes to the Climate Credit through a rigorous and transparent framework. Proposals that fundamentally alter how the credit is calculated or distributed should be supported by clear evidence that their benefits outweigh their costs, complexity, and implementation risks.

As an initial matter, the Commission should decline to adopt proposals that cannot be implemented using existing utility systems at reasonable cost, cannot be clearly explained to customers, materially reduce the value ultimately returned to customers, or create a meaningful risk of adverse impacts for low-income households. Assertions regarding implementation challenges or costs should be supported by detailed utility analysis rather than generalized statements.

For those proposals that satisfy this initial threshold, the record should enable the Commission to meaningfully compare each alternative against the existing Climate Credit distribution framework. At a minimum, proposals should identify the:

- Legal authority supporting the proposed methodology;
- Demonstrate how they advance the Commission's guiding principles and the Assigned Commissioner's priorities;
- Quantify customer impacts across different customers and usage patterns;
- Provide realistic implementation costs, schedules, and operational risks;
- Explain how implementation costs affect the net value delivered to customers;
- Evaluate impacts on conservation and electrification incentives; and
- Include clear customer communications together with appropriate reporting metrics to evaluate whether the proposal performs as intended after implementation.

4.5. Assigned Commissioner’s Electric Credit Proposal Concepts

1. Do the proposal concepts meet the requirements in CARB’s May 29, 2026 adopted regulations, and are there additional requirements/limitations that proposals need to consider?

CalCCA is still in the process of reviewing the IOU data requests provided, but even in an initial review it is clear additional refinement will be needed to determine whether variations on the status quo meet all of the requirements of CARB’s regulations. In particular, whether there is compliance with section 95892(d)(6), as discussed above.

2. Do they fulfill my stated priorities? If not, how could they be modified to better align with those priorities?

This is not yet demonstrated. The baseline and climate-zone concepts seek to advance affordability and electrification while retaining flat credit increments, but both risk conflicting with fairness and simplicity.

The baseline approach may be relatively easy to describe, but baseline status is an imprecise measure of either need or beneficial electrification. It could provide a larger credit to a high-income, high-usage customer while providing only the base credit to a CARE customer below baseline. It may also penalize efficiency and conservation. The Guidance Ruling itself recognizes that the approach's value may be obviated if most customers exceed baseline or lack a baseline allocation, and that additional assistance could flow to higher-income customers in hot zones.[28]

The climate-zone approach recognizes geographic differences but is less tailored to individual needs and does not account for other affordability issues that may differ by region. Customers with higher household incomes and less affordability challenges could receive larger credits solely because they live in a hotter zone. It also fails to account for winter peaking areas, where average annual bills may rival those in hotter climate zones, even though those costs are not concentrated in August and September. Additional subcategories might reduce that mismatch, but each added layer increases cost and makes the credit harder to explain. The Guidance Ruling acknowledges that numerous credit amounts could be complex, difficult to communicate, and costly to implement.[29]

If the Commission moves beyond the status quo, it should simplify the approach by providing a universal base credit and a single additional amount for CARE customers, subject to the data and cost record. That modification better aligns the credit with affordability, remains relatively easy to explain, and avoids treating all increased usage as beneficial electrification.

3. **In addition to providing higher credits to CARE customers, could the credit be scaled between moderate and higher-income customers and how could these customers be identified?**

Possibly, but CalCCA does not recommend creating a new income-verification system for the Climate Credit. A multi-tier income methodology would introduce privacy, data-matching, enrollment, verification, appeals, and customer-service issues. Those costs and

[28] Guidance Ruling, at 7-8.
[29] *Id.*, at 8-10.

burdens could significantly outweigh the incremental targeting benefit, particularly for a credit distributed only a few times each year.

The Commission should leverage existing, verified categories only if it elects to provide additional assistance. CARE status is the clearest existing option, although it does not identify every household experiencing affordability challenges. The California Advanced Electric Rate Design proceeding (R.26-04-009) is already examining income verification, baseline allowances, CARE, and the Base Services Charge and is better situated to develop broader income-based rate policies. The Climate Credit should remain distinct from CARE and should not be used to repair gaps in CARE eligibility or participation.

4. **Should a purely volumetric option (per kWh) be pursued, rather than the tiered approaches contemplated here? What questions and considerations should guide a choice between the two paths?**

CalCCA is still in the process of reviewing the provided IOU data requests, but a purely volumetric option does not appear to be the appropriate solution. A purely volumetric credit would be easy to express as cents per kilowatt-hour, but that apparent arithmetic simplicity obscures significant policy and implementation concerns. It would provide the greatest dollar benefit to customers who consume the most, regardless of income, efficiency, or the reason for the usage. It may reward consumption during high-demand periods increasing grid strain and weaken conservation and efficient price signals.

Should the Commission continue to explore a purely volumetric credit, at a minimum, the impacts to CARE and other low-income customers across usage levels, whether the methodology rewards beneficial electrification or consumption generally, effects on peak demand and conservation, and customer understanding and predictability should be evaluated.

5. **Does a volumetric electric credit approach (either tiered or per kWh; as conceptually proposed or otherwise) benefit customer affordability and support electrification goals? Consider the requirement in Section 748.5(a)(3) regarding provision of the credit in no more than four months, and whether this limits the credit's ability to support electrification.**

A volumetric credit may reduce bills more for high-usage customers, including some customers with electrified homes or vehicles, but it is not well designed to promote long-term electrification. Section 748.5(a)(3) concentrates the credit in no more than four high-bill months. A temporary credit in selected months is unlikely to materially influence a long-lived investment such as purchasing an electric vehicle or replacing a gas furnace or water heater. It functions principally as seasonal bill assistance.

Moreover, electricity usage is not a reliable measure of ability to pay or of beneficial electrification. A volumetric credit could provide less assistance to a low-income customer who suppresses usage and more assistance to a high-income customer with a large home and discretionary load. It could also disadvantage customers whose electrification investments are paired with efficiency measures.

If the Commission's objective is to encourage electrification through marginal price signals, the California Advanced Electric Rate Design, General Rate Cases, or other proceedings are the more appropriate forums. The Climate Credit should retain its comparative strength: a visible, predictable infusion of bill relief.

6. **What implementation issues or considerations do these options raise?**

The principal implementation challenges are cost, timing, billing-system capability, data availability and quality, billing accuracy, and customer understanding. Beyond those practical considerations, the baseline and climate-zone proposals also require the Commission to resolve numerous threshold design questions before they can be fairly evaluated.

For example, the Commission would need to determine:

- Which historical usage period establishes eligibility;
- How customers who move, change tariffs, lack a full year of billing history, or receive corrected bills should be treated;
- How the methodology applies to Medical Baseline, master-metered, NEM, and NBT customers;
- Whether climate zones and baseline territories should be standardized across utilities;
- How retroactive billing adjustments affect eligibility or credit amounts;
- When CARE eligibility should be measured; and
- How the program can be explained clearly when similarly situated customers receive different Climate Credit amounts.

7. **Should other modifications be made, such as to remove or reduce credits for second homes or vacation rentals (for utilities with such tariffs), or make any other programmatic changes?**

While CalCCA would likely support this option, the initial review of the utility provided data requests indicate that this information is not tracked. Excluding second homes or vacation rentals would require reliable identification, verification, continuing updates, and a process for correcting errors. Customer account data may not consistently distinguish a second home, seasonal residence, long-term rental, and vacation rental. Misclassification could deny a credit to an eligible customer, while administration could consume much of the amount reallocated.

8. **What additional or different reporting or oversight should accompany these changes to the credit?**

If the Commission adopts a new Climate Credit methodology, it should require annual reporting for at least the first three distribution years to confirm that the program is operating as intended and delivering the expected customer benefits. At a minimum, reporting should compare:

- Actual implementation and ongoing administrative costs against projections;
- Identify the total allowance proceeds received and the net amounts ultimately returned to customers;
- Evaluate customer outcomes across relevant customer groups, including, but not limited to, CARE, FERA, Medical Baseline, deed-restricted affordable housing, master-metered, NEM, NBT, climate zone, and usage categories;

- Summarize billing corrections, customer complaints, and customer understanding of the program; and
- Assess whether the methodology is achieving its intended distributional and policy objectives.

The Commission should also establish a formal reevaluation point to determine whether the new methodology continues to justify its costs and complexity. If implementation costs materially exceed estimates, reduce the aggregate value returned to customers, create unanticipated customer confusion, or produce unintended impacts for low-income or other customer groups, the Commission should retain the ability to modify or discontinue the methodology. Finally, reporting should monitor the expected decline and year-to-year variability in Climate Credit amounts so the Commission can proactively address those trends through future policy decisions rather than repeatedly redesigning the Climate Credit itself.

4.6. Assigned Commissioner's Natural Gas Credit Proposal Concepts

1. **Do you agree that the gas credit is likely to decline due to declining allowance allocations/revenues? Do you agree that this proceeding should make minimal changes to the gas credit, relative to the electric credit, due to these declining benefits?**

Yes. The Guidance Ruling reasonably concludes that declining gas allowance allocations reduce the potential benefit of a complex redesign and increase the importance of preserving customer value.[30] The Commission should make only the changes necessary to comply with CARB's 2028 requirements and protect low-income customers.

2. **For CARB's §95893(d)(8) requirement related to the usage of gas allowances, does my proposal concept meet the requirement that 30% of the total allowances primarily benefit low-income ratepayers? Is there an alternative to CARE enrollment status that CPUC should apply? Should an amount higher than the minimum required 30% be allocated to protecting low-income customers?**

CalCCA has no comments at this time.

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30 Guidance Ruling, at 11-12.

3. **Does this concept effectively protect low-income gas customers? What changes to this concept do you suggest? What modifications could be made to better benefit master-metered gas customers?**

CalCCA has no comments at this time.

4. **What additional or different reporting or oversight should accompany these changes to the credit?**

The transition away from the natural gas Climate Credit should be accompanied by clear, targeted communications to affected customers, particularly vulnerable and low-income households that are on the margins and may not be enrolled in CARE.

VI. 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,

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Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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**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 COMMENTS ON ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENT ON ASSIGNED COMMISSIONER'S PROPOSAL ON FLEXIBLE SERVICE CONNECTIONS

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July 27, 2026

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SUMMARY OF RECOMMENDATIONS[1]

The Commission should:

- Establish a working group and conduct workshops (WS) to address competition and market access considerations, including investigating a demand flexibility marketplace to complement the IOUs' Grid-Edge DERMS in the context of an overarching DER orchestration framework before finalizing the Proposal;

- Direct the IOUs to delay incurring additional expenditures for Grid-Edge DERMS deployment, beyond those previously approved, until after the fair market competition and marketplace platform evaluations have been completed to capture any potential cost and operational efficiencies;

- Include a discussion of a marketplace platform in the proposed WSs to support a more holistic DER orchestration framework designed to minimize ratepayer costs while supporting the state's policy goals;

- Evaluate the RIIO costs and benefits mechanisms employed by the UK energy regulator to inform the development of cost-effectiveness measures for demand flexibility;

- Incorporate the existing SCT when evaluating DER cost-effectiveness to capture environmental and societal benefits of demand flexibility measures; and

- Modify the Proposal to make participation in RTP programs or rates optional for customers participating in Variable or Dynamic Operating Envelopes until a complete evaluation of RTP pilot programs demonstrates their benefits.

[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 Energy Resource Future.	R.21-06-017

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENT ON ASSIGNED COMMISSIONER'S PROPOSAL ON FLEXIBLE SERVICE CONNECTIONS

California Community Choice Association[2] (CalCCA) submits these comments pursuant to the *Assigned Commissioner's and Administrative Law Judge's Ruling Requesting Comment on Assigned Commissioner's Proposal on Flexible Service Connections*[3] (Ruling), dated July 7, 2026, and the *Email Ruling Granting Schedule Modification*,[4] dated July 13, 2026. The Ruling seeks comments on the Assigned Commissioner's Proposal[5] (Proposal) and questions in Section 2 of the Ruling.

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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 *Assigned Commissioner's and Administrative Law Judge's Ruling Requesting Comment on Assigned Commissioner's Proposal on Flexible Service Connections*, Rulemaking (R.) 21-06-017 (July 7, 2026), https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=610354104.

4 *E-Mail Ruling Granting Schedule Modification*, R.21-06-017 (July 13, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M610/K764/610764723.PDF.

5 Ruling, Attachment 2, *Flexible Service Connections: Advancing Affordable Electrification Through Efficient Distribution Grid Utilization* (July 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M610/K354/610354105.PDF.

I. INTRODUCTION

The Assigned Commissioner's Proposal of a Flexible Service Connections (FSC) framework offers a pathway to expand the use of distributed energy resources (DER) to both accelerate the energization of new loads on constrained circuits and to avoid or defer costly grid upgrades. The Proposal, if adopted, could deliver ratepayer benefits, improve grid operations, provide value to flexible DER providers, and help achieve the state's climate and affordability goals. CalCCA appreciates the Proposal's consideration of competitive and market access concerns, which have been previously raised by community choice aggregators (CCA) and other stakeholders in this and other tracks of this proceeding.

CalCCA generally supports the Proposal but encourages the California Public Utilities Commission (Commission) view it in the broader context of a holistic DER orchestration framework. The Proposal provides for the IOUs to deploy Grid-Edge DER Management Systems (DERMS) to monitor current and emerging grid conditions and to signal DERs for demand flexibility services, thereby supporting new loads energizing on constrained grid infrastructure. CalCCA does not object to this approach, but suggests it be considered only after addressing the competition and market access considerations highlighted in the Proposal, including evaluating a demand flexibility marketplace platform that could greatly expand the pool of available DER. While Grid-Edge DERMS may be appropriate for the specific FSC use case addressed in the Proposal, there may be design or operational efficiencies to be gained from adding a flexibility marketplace that should be considered, and fair market competition issues to resolve before the Commission adopts the Proposal. Additionally, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (collectively, the investor-owned utilities (IOUs)) should not begin deploying new Grid-Edge

DERMS capabilities, beyond what the Commission has already approved, until these evaluations have concluded.

As discussed in response to the Ruling Questions below, the Commission should:

- Establish a working group and conduct workshops (WS) to address competition and market access considerations, including investigating a demand flexibility marketplace to complement the IOUs' Grid-Edge DERMS in the context of an overarching DER orchestration framework before finalizing the Proposal;
- Direct the IOUs to delay incurring additional expenditures for Grid-Edge DERMS deployment, beyond those previously approved, until after the fair market competition and marketplace platform evaluations have been completed to capture any potential cost and operational efficiencies;
- Include a discussion of a marketplace platform in the proposed WS to support a more holistic DER orchestration framework designed to minimize ratepayer costs while supporting the state's policy goals;
- Evaluate the Revenue = Incentives + Innovation + Outputs (RIIO) costs and benefits mechanisms employed by the United Kingdom (UK) energy regulator to inform the development of cost-effectiveness measures for demand flexibility;
- Incorporate the existing Societal Cost Test (SCT) when evaluating DER cost-effectiveness to capture environmental and societal benefits of demand flexibility measures; and
- Modify the Proposal to make participation in real-time pricing (RTP) programs or rates optional for customers participating in Variable or Dynamic Operating Envelopes until a complete evaluation of RTP pilot programs demonstrates their benefits.

II. CALCCA'S COMMENTS TO QUESTIONS IN SECTION 2 OF THE RULING: QUESTIONS ON PROPOSAL

1. Please provide feedback on the Proposal itself, identifying any concerns with and/or support for the direction and background. Comments on the Proposal shall be provided within the same structure as the Proposal where possible (e.g., discussion of Operating Envelopes should come in Section 4 of party comments).

The Proposal lays out a pathway for leveraging DERs and demand flexibility to avoid costly grid upgrades and optimize existing grid capacity, providing benefits to ratepayers and to customers seeking to energize new loads. CalCCA generally supports the Proposal as a meaningful addition to the static FSC mechanism recently adopted in the Energization

Proceeding[6] and appreciates the Commission's thoughtful approach to ensuring a level playing field for CCA and non-IOU-managed DER participation. While deploying Grid-Edge DERMS may be a reasonable approach for IOUs to implement FSCs, the Commission should consider a holistic approach to DER orchestration before implementing the Proposal by establishing a working group to address the Competition and Market Access Considerations in Section 7 of the Proposal.[7] Specifically, the Commission should consider the potential benefits of a marketplace platform that could serve as the foundation for enrolling and managing DERs for multiple use cases, including the infrastructure deferral opportunities identified in the Proposal.

An Enterprise DERMS, also known as a Grid DERMS, enables IOUs to manage their own DERs but is not intended to control behind-the-meter (BTM) resources.[8] It is tightly integrated with the IOUs' Advanced Distribution Management System (ADMS) and other enterprise systems, but is less scalable and requires a more costly communications infrastructure.[9] A Grid-Edge DERMS is specifically designed to manage large numbers of customer-owned BTM devices, including smart appliances, and generally uses low-cost, cloud-based monitoring and controls, enabling it to scale.[10] Enterprise and Grid-Edge DERMS offer distinct advantages and are increasingly deployed together to manage both utility- and non-utility-owned DERs.

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6 *See, generally,* Decision (D.) 26-02-025, *Establishing a Standard Offer for Flexible Service Connections*, R.24-01-018 (Energization Proceeding) (Feb. 10, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M598/K715/598715449.PDF.

7 Proposal, at 39-40.

8 Stacia Secreriat, "Grid DERMS vs. Grid-Edge DERMS: a Complete Utility Guide," *Virtual Peaker*, 3 June 2026, https://virtual-peaker.com/blog/grid-edge-derms-versus-grid-derms/.

9 Astrid Atkinson, "What is Grid Orchestration and how does it differ from DERMS?," *Camus Energy*, https://www.camus.energy/gridorchestration#Air-Traffic.

10 Amber Mullaney, "The Difference Between Grid-Edge DERMS and Grid DERMS," *Virtual Peaker*, 7 Aug. 2024, https://virtual-peaker.com/blog/the-difference-between-grid-edge-derms-grid-derms/.

In contrast, flexibility marketplaces facilitate the acquisitions of and transactions between utilities and flexible service providers, matching system needs with resource capabilities and availability. The marketplace operator, in coordination with the IOUs, prequalifies bidders and resources, publishes utility flexibility competitions, ranks bids, presents utility contracts, runs settlements, and may relay dispatch instructions.[11] The IOUs communicate their flexibility needs and instructions via their Enterprise or Grid-Edge DERMS, using standardized communications protocols such as Open Automated Demand Response (OpenADR) or Institute of Electrical and Electronic Engineers (IEEE) 2030.5. A centralized flexibility market can provide utilities with greater access to DER assets that do not participate in utility programs or contracts, increasing the number of resources available and the potential for system deferral.[12] It could also reduce participation barriers for DER providers by offering a single point of access to multiple market offerings and value-stacking opportunities.[13]

During this proceeding's Track 2 Transmission System Operator (TSO) – Distribution System Operator (DSO) Coordination Workshop (TSO-DSO WS), the independent flexibility market operator Piclo presented the UK approach to managing demand flexibility. Piclo stated that the marketplace platform they operate accommodates long-, medium-, and short-term flexibility needs.[14] The long-term use cases include permanent (non-wire) alternatives and bridging solutions, similar to those being considered for this Proposal. This approach may still necessitate that IOUs deploy Grid-Edge DERMS to monitor grid conditions and signal

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11 TSO-DSO WS Presentation, at 131.

12 Enrique Rael, "Unlocking the Full Potential of Distributed Energy – Combining Local Flexibility Markets with Utility DERMS," *Piclo*, February 11, 2025, https://www.piclo.com/blog/unlocking-the-full-potential-of-distributed-energy.

13 TSO-DSO WS Presentation, at 132.

14 *Track 2 Workshop Report: TSO-DSO Coordination*, R.21-06-017 (July 9, 2026), at 130, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M610/K353/610353842.PDF.

responses, but the addition of a marketplace platform may influence how, and to what extent, the IOUs must develop these capabilities. It could also influence communication protocols and interoperability requirements for non-IOU-managed resources.

If the goal of these collective efforts is to maximize ratepayer value and optimize the existing grid capacity, the Commission should take a holistic approach to ensure that duplicative and potentially expensive control platforms are not deployed. Further, achieving these objectives requires high levels of DER and flexible resource participation. A single marketplace platform that supports long-, medium-, and short-term use cases lowers participation barriers for demand flexibility providers, ensuring robust competition, a level playing field, and operational efficiencies. It could also allow IOUs to leverage resources enrolled in short-term, intraday markets as a backup to long-term deferral agreements during abnormal grid conditions or when a contracted resource is unexpectedly unavailable. The Commission should establish a working group and conduct technical workshops to investigate this option within the Section 7 Recommendations[15] and the overarching DER orchestration framework before finalizing the Proposal and before authorizing the IOUs to incur expenses related to the deployment of Grid-Edge DERMS, beyond what has already been authorized.

2. **Section 9 of the Proposal includes a summary of the recommendations for Commission action. Please provide feedback on the recommendations, being as specific as possible regarding the pros and cons of the proposed recommendations, and on the feasibility of implementation.**

CalCCA provides responses to the Proposal recommendations below.

A. Section 3 Recommendations

1) Extension of Standard Offer to SDG&E customers

CalCCA supports this recommendation.

15 Proposal, at 54-55.

2) Large IOUs to record and provide values helpful to dedicated infrastructure customers independently implementing Operating Limits

CalCCA supports this recommendation.

3) Rule 2 – Updating definitions of Controlled Load and alignment language between Large IOUs

CalCCA supports this recommendation.

4) Flexible connection evaluation requirements

CalCCA supports this recommendation.

B. Section 4 Recommendations

1) Large IOUs to provide Limited Power arrangements as the default mitigation for distribution transformer upgrades

CalCCA supports this recommendation.

2) SCE and SDG&E to implement Variable Operating Envelope bridging solutions modeled after PG&E's Flex Connect

CalCCA supports this recommendation.

3) Leveraging Enterprise DERMS based Variable Operating Envelope infrastructure for centralized Dynamic Operating Envelopes to address abnormal grid conditions

CalCCA supports the recommendation for the IOUs to host a workshop to further discuss the possibility of Dynamic Operating Envelopes, with the caveat that the workshop should include a discussion of a marketplace platform to expand the pool of available resources that could be leveraged for this purpose.

4) SCE and SDG&E should implement Grid Edge DERMS for 100 A residential customers whose EV charging would normally require an upgrade

CalCCA supports requiring SCE and SDG&E to implement a Grid-Edge DERMS approach for 100-ampere residential customers, using local controls as an interim measure to expand access to electric vehicle (EV) charging for customers on constrained secondary systems. The Commission should, however, weigh the costs, benefits, and scalability of this approach against a potential marketplace solution before considering it the default mitigation for residential EV charging.

5) Establish a series of Energy Division-led workshops with reports to further develop Grid Edge DERMS solutions

CalCCA supports the recommendation for Energy Division-led workshops to explore the development of Grid-Edge DERMS, with the caveat that they should occur after, and incorporate the findings of, the working groups discussing Section 7 Recommendations[16] and the evaluation of a marketplace platform to support a holistic DER orchestration framework that minimizes ratepayer costs while advancing the state's climate policy goals.

C. Section 5 Recommendations

1) Direct IOUs to propose implementation of baseline cybersecurity considerations from the SIO-CS

CalCCA has no comment at this time.

D. Section 6 Recommendations

1) Establish durable non-bridging solutions for new flexible connections

CalCCA supports this recommendation.

2) Clarification that current Static Variable Operating Envelope customers can elect to transition from a bridging to a persistent non-bridging solution

CalCCA supports this recommendation.

3) PG&E should formalize its Flex Connect offering and expand its non-bridging Flex Connect Generation option to load customers

CalCCA supports this recommendation.

[16] *Ibid*.

4) Large IOUs should be required to implement a non-bridging version of the Standard Offer

CalCCA supports this recommendation.

E. Section 7 Recommendations

1) Interoperability and Customer Choice Requirements

CalCCA strongly supports this recommendation and appreciates the Commission's efforts to ensure a level playing field for CCA, aggregator, and self-managed program participation in the proposed FSC framework. CalCCA recommends expanding this recommendation to establish a formal working group to address the Competition and Market Access Considerations in Section 7 of the Proposal.[17] This working group should also be tasked with investigating a demand flexibility marketplace to complement the IOUs' Grid-Edge DERMS in the context of an overarching DER orchestration framework. The working group should also address proprietary vendor arrangements, interoperability, customer choice, and local control within either an IOU Grid-DERMS or a marketplace platform.

F. Section 8 Recommendations

1) Real-Time Pricing Rate Enrollment

CalCCA opposes this recommendation for the following reasons cited in its December 19, 2025, Comments on the Near-Term Flexible Connections Ruling:[18]

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[17] Proposal, at 39-40.

[18] *Assigned Commissioner's Ruling Seeking Additional Information on DER Enabled Near Term Flexible Connections* (Near-Term Flexible Connections Ruling), R.21-06-017 (Nov. 3, 2025), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M586/K143/586143237.PDF.

> Initial evaluations of dynamic pricing pilots were not favorable, and current pilots are ongoing and have yet to be evaluated. PG&E's response to the Ruling's Question highlights its concern that "not all customers who can manage load within a variable or dynamic operating envelope may be able to manage load under a complex dynamic pricing structure." PG&E further expresses its support for allowing customers to opt in to a dynamic pricing rate rather than being required to do so. It is, therefore, premature to consider requiring flexible connection customers to enroll in pilots and default to a dynamic pricing rate, especially given the uncertain impacts on customers utilizing variable or dynamic operating envelopes.[19]

For the reasons cited above, the Commission should not require customers participating in Variable or Dynamic Operating Envelope options to be defaulted onto RTP rates or programs. Rather, these customers should be presented with the option to join the available rate or program when enrolling in the Variable or Dynamic Operating Envelope mechanisms. While such optionality will be important moving forward, this is especially true during the period when complete evaluations of the RTP pilot programs have not yet been completed.

2) Data Tracking

CalCCA opposes defaulting customers operating under a Variable or Dynamic Operating Envelope to an RTP program or rate, but does not oppose tracking data related to customers' voluntary participation in RTP rates.

3. **Section 9 of the proposal summarizes recommendations for Commission action based on the stated goal of the proposal. Do parties find that any additional recommendations are warranted in support of this goal?**

The Commission should consider adding a recommendation to investigate the possible deployment of a centralized demand flexibility marketplace before requiring the IOUs to file

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[19] CalCCA's Opening Comments on Near-Term Flexible Connections Ruling, R.21-06-017 (Dec. 19, 2025), at 12, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M591/K672/591672890.PDF.

Advice Letters for implementing Grid-Edge DERMS, as discussed in CalCCA's response to Question 1.

4. **For the proposed Advice Letters what, if any, additional implementation or program design elements should be addressed each Advice Letter. Do parties have recommendations on how to consolidate advice letters or make the process more efficient?**

CalCCA has no response at this time.

5. **Many of the Proposal's recommendations are premised on the goal of affordability and ratepayer savings from greater capacity utilization, speed to power, and deferral or avoidance of upgrade capital expenditure. To realize these goals, quantification of ratepayer costs and benefits will be necessary. For each recommendation how should the IOUs measure, track and report key costs and benefit metrics?**

The Commission should investigate cost-effectiveness evaluation methodologies used in other jurisdictions that have deployed flexibility marketplaces to inform the discussion of ratepayer costs and benefits associated with leveraging DER to avoid or defer grid investments. Specifically, the Commission should look at the UK flexibility markets, which were launched in 2018 to help DSOs acquire demand flexibility to advance the country's net-zero energy goals while keeping rates affordable.[20] Since the launch of these markets, the UK's National Energy System Operator has set a goal of 12 Gigawatts of consumer-led flexibility by 2030, an increase of 33 percent from 2024.[21] The continued growth of these markets is a strong indication of the environmental and societal benefits derived from demand flexibility.

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20 *See, e.g.*, "Energy UK Explains: How consumer-led flexibility works in power markets," *Energy UK*, Apr. 2026, https://www.energy-uk.org.uk/wp-content/uploads/2026/04/Energy-UK-Explains-How-consumer-led-flexibility-works.pdf.

21 *See, e.g.*, Suzanne Lycett, "5 Energy Flexibility Market Developments and Updates from the UK for 2026," *Electron*, 06 May 2026, https://electron.net/uk-flexibility-markets-developments-and-updates/.

In furtherance of the objective to expand flexibility markets, Energy Networks Association (ENA), an industry association representing grid operators in the UK, published the Common Evaluation Methodology (CEM) Tool (Version 3) in 2024 to:

> [P]rovide transparency on how decisions are made to choose the most suitable solution to meet network needs between traditional network asset solutions (reinforcement) and procuring flexibility services from generators, storage operators or demand side response.[22]

Additionally, Great Britain's energy regulator, the Office of Gas and Electricity Markets (Ofgem), is developing new rules for evaluating DSO performance under their RIIO Electricity Distribution Price Control (ED3) framework (RIIO-ED3).[23] Scheduled for implementation in 2028, the new RIIO-ED3 framework includes a "build and flex" requirement, explained below:

> A new 'build and flex' approach to minimise costs: DNOs will be required to prioritise flexibility and demand-side solutions to shift and manage demand so the existing network capacity is maximised before investing in physical upgrades, reinforcements and building. This reflects that traditional infrastructure projects are capital-intensive, while flexibility can deliver capacity more efficiently and at lower cost to consumers. Ofgem will enforce this through business plan assessment and regulatory tools, ensuring new build only proceeds where constraints are persistent and demand is sufficiently certain.[24]

The evolution of demand flexibility markets in the UK, and the lessons learned as the markets have grown and matured, can help inform the Commission's efforts to ensure that the proposed FSC and any future DER flexibility services provide ratepayer and grid benefits.

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[22] Energy Networks Association "Common Evaluation Methodology Tool v3 & Supporting Materials," Nov. 2024, https://www.energynetworks.org/publications/common-evaluation-methodology-tool-and-supporting-materials.

[23] Ofgem, "*Framework Decision: Electricity Distribution Price Control (ED3)*," 30 Apr. 2025, https://www.ofgem.gov.uk/decision/framework-decision-electricity-distribution-price-control-ed3.

[24] Ofgem, "Ofgem sets rules for 2028 to 2033 grid investment to meet growing electricity demand," *Ofgem*, May 21, 2026, https://www.ofgem.gov.uk/press-release/ofgem-sets-rules-2028-2033-grid-investment-meet-growing-electricity-demand.

Importantly, the UK's RIIO framework helps ensure that the DSO's financial motives align with the nation's climate and affordability goals. Despite differences in regulatory and utility business structures between the UK and California's IOUs, the underlying concept of aligning utility/DSO financial imperatives with policy goals is a key consideration for the success of any proposed demand flexibility framework or program.

The existing RIIO-ED2 structure also allows DSOs to capture societal and environmental benefits of their operations, supporting policy goals.[25] The Commission should consider including social and environmental benefits in its evaluation of the costs and benefits of the proposed FSC, and any future demand flexibility framework, using the existing Societal Cost Test (SCT) adopted in D.24-07-015.[26] Although D.24-07-015 adopted the SCT as information-only, it states that:

> The SCT, as an information-only test, allows the Commission the flexibility of balancing the societal costs and benefits of DER programs against any potential affordability impacts that could result from funding such programs through electricity rates. The Commission, when using the SCT as an information-only test, has the flexibility to weigh and consider multiple factors when making demand-side resource decisions, including the costs ratepayers pay in electric rates, societal benefits of reduced air pollution, environmental benefits of cleaner energy, and impacts on affordability.[27]

The potential benefits of avoided or deferred capital investment and greater utilization of existing grid capacity, as articulated in the Proposal, should result in a positive cost-effectiveness determination in many cases where flexible service connections are deployed. However,

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25 *See, e.g.*, SP Electricity North West, *Social DSO, Delivering Benefits in ED2* (SP Electricity North West, July 2026), https://www.enwl.co.uk/globalassets/future-energy/dso/reports/social-dso/dso---delivering-consumer-value-in-ed2.pdf/.

26 *See generally*, D.24-07-015, *Adopting the Societal Cost Test*, R.22-11-013 (July 15, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M535/K822/535822173.PDF.

27 D.24-07-015, at 23.

D.24-07-015 authorizes the Commission to incorporate SCT results in determining the cost-effectiveness of demand-side resource measures. The Commission should require that the results of the SCT be included in any cost-benefit evaluation of the proposed SCT measures. The Commission should also require Energy Division to evaluate the UK's RIIO framework to develop a more robust cost-evaluation methodology that captures the full range of costs and benefits associated with demand-flexibility use cases.

6. **How should IOUs ensure the existence of bridging solutions, non-bridging solutions, or the change from a bridging solution to a non-bridging solution are timely communicated with the California Energy Commission for forecasting purposes?**

CalCCA has no response at this time.

7. **The proposal recommends the Commission direct SDG&E to stand up a static FSC offering that is aligned with the requirements directed in D.26-02-025 for PG&E and SCE.3 a. For SDG&E to implement this proposal, what, if any, modifications to the requirements directed in D.26-02- 025 should the Commission consider?**

CalCCA has no response at this time.

8. **What hardware, software, or data sharing safeguards may be needed to ensure that customers can obtain a flexible connection without being restricted by proprietary arrangements?**

CalCCA supports the use of open-source communication protocols, such as OpenADR 3.0, for a marketplace platform or Grid-Edge DERMS signals to maximize participation in demand-flexibility markets or IOU-managed FSC options. CalCCA discussed the benefits of OpenADR for this purpose during the February 20, 2026, Track 3 All-Party Workshop.[28] The Proposal also correctly identifies stakeholder concerns about some equipment manufacturers' use of proprietary communications protocols and the practice of charging fees for access to those

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[28] *Track 3 All-Party Workshop Report*, R.21-06-017 (Mar. 3, 2026), at 10, 20, 139, 141, 142, and 144, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K998/602998929.PDF.

devices (*i.e.,* ”vendor lock-in”). CalCCA supports the recommendation to establish a workshop process to explore options for eliminating such barriers and facilitating participation in FSC offerings, including a potential flexibility marketplace.

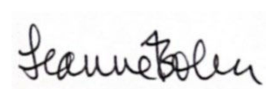
9. Are there any safety concerns that should be highlighted?

CalCCA has no response at this time.

III. 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,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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**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 OPENING COMMENTS ON ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGE'S RULING ISSUING QUESTIONS ON THE DISTRIBUTED ENERGY RESOURCES ORCHESTRATION WORKSHOP REPORTS

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July 27, 2026

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SUMMARY OF RECOMMENDATIONS[1]

The Commission should defer adopting a DER orchestration framework until completing the following steps:

- Adopt the following additional guiding principles to mitigate potential conflicts of interest, prevent market manipulation, and ensure a level playing field for non-IOU managed DERs under an IOU-led DER orchestration framework: (1) nondiscriminatory market access, operations, and dispatch; (2) independent monitoring and oversight of the DSO and market functions; (3) optimization of existing distribution grid capacity before authorization of capital investments; (4) competitive neutrality of the DSO and marketplace operator; (5) fair compensation for DER flexibility services; and (6) timely access to accurate customer usage, DER, integration capacity analysis, and grid data;

- Consider a holistic approach to developing a DER orchestration framework by incorporating all demand-flexibility use cases, including FSCs, to capture potential operational efficiencies and cost savings;

- Evaluate the costs and benefits of a flexibility marketplace working in conjunction with the IOUs' Grid-Edge DERMS to scale participation and create additional ratepayer benefits;

- Establish the following WGs to address unresolved issues from the two WSs: (1) DER Visibility and Data Systems; (2) TSO-DSO Operational Coordination; and (3) Market Design and Governance; and

- Investigate a decentralized DER data sharing framework that relies on secure data exchanges under a trust framework to ensure DER data remains up-to-date and does not become unusable.

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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 Energy Resource Future.	R.21-06-017

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGE'S RULING ISSUING QUESTIONS ON THE DISTRIBUTED ENERGY RESOURCES ORCHESTRATION WORKSHOP REPORTS

California Community Choice Association[2] (CalCCA) submits these opening comments pursuant to the *Assigned Commissioner's and Administrative Law Judge's Ruling Issuing Questions on the Distributed Energy Resources Orchestration Workshop Reports*[3] (Ruling), dated July 9, 2026. The Ruling seeks responses to questions about the Track 2 Workshop (WS) Report: Distribution System Operator (DSO) Distributed Energy Resources (DER) Orchestration WS (DER Orchestration WS Report)[4] and the Track 2 WS Report: Transmission System Operator (TSO)-DSO Coordination WS (TSO-DSO WS Report) (collectively, WS Reports).[5]

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[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] *Assigned Commissioner's and Administrative Law Judge's Ruling Issuing Questions on the Distributed Energy Resources Orchestration Workshop Reports*, Rulemaking (R.) 21-06-017 (July 9, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M610/K354/610354178.PDF.

[4] Ruling, Attachment 2, *Track 2 Workshop Report: Distribution Operator DER Orchestration*, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M610/K353/610353944.PDF.

[5] Ruling, Attachment 3, *Track 2 Workshop Report: TSO-DSO Coordination,* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M610/K353/610353842.PDF.

I. INTRODUCTION

CalCCA appreciates the opportunity to provide comments on the WS Reports, summarizing discussions held at the DSO DER Orchestration WS (WS 1) on May 21, 2026,[6] and the TSO-DSO Coordination WS (WS 2) on June 5, 2026.[7] WS 1 provided stakeholders with the opportunity to discuss the foundational elements of a proposed investor-owned utility (IOU)[8] -led DER orchestration framework. WS 2 further developed the record on enhancing coordination between the IOUs and the California Independent System Operator (CAISO), in its capacity as the TSO, enhancing CAISO visibility of DERs, and aligning DSO, TSO, and stakeholder priorities for DER orchestration.

The WS Recordings and Reports highlight significant differences among stakeholders on the proposed DSO functions, governance, DER visibility, data architecture, communications and interoperability protocols, TSO-DSO operational coordination, and overall market design. Before advancing a DER orchestration framework and requiring IOUs to file applications to develop their own frameworks, the California Public Utilities Commission (Commission) should resolve these outstanding issues. ***First***, the Commission should adopt a final set of guiding principles, including principles concerning governance and market access, to ensure open and fair market access and to align the IOU DER orchestration outcomes with policy goals. ***Second***, the Commission should take a holistic approach by incorporating multiple demand flexibility use cases, including flexible service connections (FSC), and developing flexible marketplace platforms to maximize DER participation and enhance ratepayer benefits. ***Third***, working groups

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6 *See* WS 1 Recording, *DER Orchestration Framework Development* (DER Orchestration WS Recording), R.21-06-017 (May 21, 2626), https://youtu.be/iok0dMjMw9I.

7 *See* WS 2 Recording, *TSO-DSO Coordination* (TSO-DSO WS Recording), R.21-06-017 (June 5, 2026), https://youtu.be/AHbDF0PsbZM.

8 As used herein, "IOUs" refer collectively to Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE).

should be established to investigate and propose solutions to address all unresolved issues identified in the WS and WS Reports.

As discussed in response to the Ruling Questions and in comments on the WS Reports below, the Commission should defer adopting a DER orchestration framework until completing the following steps:

- Adopt the following additional guiding principles to mitigate potential conflicts of interest, prevent market manipulation, and ensure a level playing field for non-IOU managed DERs under an IOU-led DER orchestration framework: (1) nondiscriminatory market access, operations, and dispatch; (2) independent monitoring and oversight of the DSO and market functions; (3) optimization of existing distribution grid capacity before authorization of capital investments; (4) competitive neutrality of the DSO and marketplace operator; (5) fair compensation for DER flexibility services; and (6) timely access to accurate customer usage, DER, integration capacity analysis, and grid data;
- Consider a holistic approach to developing a DER orchestration framework by incorporating all demand-flexibility use cases, including FSCs, to capture potential operational efficiencies and cost savings;
- Evaluate the costs and benefits of a flexibility marketplace working in conjunction with the IOUs' Grid-Edge DER Management Systems (DERMS) to scale participation and create additional ratepayer benefits;
- Establish the following working groups (WG) to address unresolved issues from the two WS: (1) DER Visibility and Data Systems; (2) TSO-DSO Operational Coordination; and (3) Market Design and Governance; and
- Investigate a decentralized DER data sharing framework that relies on secure data exchanges under a trust framework to ensure DER data remains up-to-date and does not become unusable.

II. CALCCA'S COMMENTS IN RESPONSE TO THE QUESTIONS IN SECTION 2 OF THE RULING

1. Are there any factual inconsistencies or areas needing clarification in the summary workshop reports set out in Attachments 1 and 2. Are the party perspectives discussed in the respective reports accurate?

See CalCCA's comments in Sections III and IV below.

2. What, if any, additional information or development on a proposed orchestration framework should be considered before directing the IOUs to file DER orchestration framework applications? What recommendations do parties have regarding any additional work needed and timelines for completing such work, including timing for filing of IOU DER orchestration applications?

The WS Reports highlight substantial unresolved questions and issues, including, but not limited to, DSO functions and roles, governance and oversight, DER visibility, data architecture, TSO-DSO operational coordination, and market design. Given the abundance and significance of unresolved issues, the Commission should defer applications for a DER orchestration framework until these issues can be comprehensively resolved. ***First***, the Commission should finalize the DSO guiding principles proposed in the DER Orchestration Ruling[9] to serve as a foundation for developing a consistent DER orchestration framework. CalCCA's Opening Comments on the DER Orchestration Ruling proposed a number of additional guiding principles to address governance issues and ensure a fair and competitive market, including:

- 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.[10]

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[9] *Assigned Commissioner's Ruling on Track 1 and Track 2 DER Orchestration* (DER Orchestration Ruling), R.21-06-017 (Mar. 3, 2026), at 7, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K997/602997407.PDF.

[10] *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), at 12, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M605/K328/605328509.PDF.

CalCCA's Comments on the FSC Ruling,[11] filed concurrently with these Comments, highlight the need to align the IOUs' financial imperatives with state policy goals, including carbon reduction and rate affordability.[12] Establishing any type of DER orchestration framework requires significant time, money, and effort, necessitating careful consideration of governance structures, nondiscriminatory market access, appropriate incentives, and compensation mechanisms to ensure the IOUs maximize DER flexibility opportunities. Only if these issues are addressed can DER orchestration fulfill the promise of reduced grid investments, optimized grid operations, and the resulting ratepayer savings.

As discussed in greater detail in CalCCA's Comments on the FSC Ruling, the Commission should evaluate governance structures, incentive mechanisms, and cost-benefit structures and mechanisms adopted by the Office of Gas and Electricity Markets (Ofgem) for the United Kingdom's (UK) DSO framework.[13] Ofgem's Revenue = Incentives + Innovation + Output (RIIO) framework establishes price controls to ensure DSOs support Great Britain's climate and other policy goals. The RIIO framework establishes revenue targets, which are determined by the DSOs' ability to safely and reliably operate the grid, provide value to ratepayers, meet customer satisfaction and reliability objectives, and earn incentives for improving service.[14] An evaluation of Ofgem's oversight of regional DSOs will provide valuable

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[11] *See Assigned Commissioner's and Administrative Law Judge's Ruling Requesting Comment on Assigned Commissioner's Proposal on Flexible Service Connections* (FSC Ruling), R.21-06-017 (July 7, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M610/K354/610354104.PDF.

[12] *CalCCA's Comments on the Assigned Commissioner's and Administrative Law Judge's Ruling Requesting Comment on Assigned Commissioner's Proposal on Flexible Service Connections*, R.21-06-017 (filed concurrently with these comments on July 27, 2026), at 12.

[13] *Id*. at 11-13.

[14] Ofgem, "Energy Network Price Controls," https://www.ofgem.gov.uk/energy-regulation/how-we-regulate/energy-network-price-controls.

insights for refining the guiding principles and should be undertaken before the Commission adopts a DER orchestration framework.

Second, the Commission should take a holistic approach to developing a DER orchestration framework by incorporating all demand-flexibility use cases, including static and dynamic FSCs and generation interconnections. The platforms, systems, and mechanisms that control flexible resources across these use cases are interrelated, and a DER orchestration framework encompassing all related use cases could deliver operational efficiencies and cost savings.

In furtherance of this objective, the Commission should evaluate the costs and benefits of a flexibility marketplace working in conjunction with the IOUs' Grid-Edge DERMS. A marketplace platform facilitates transactions between IOUs and flexibility providers, giving them access to the broader population of non-IOU-managed DERs and reducing the complexity and costs of participation for flexibility providers. The addition of a flexibility marketplace accelerates DER participation and creates more opportunities for grid infrastructure deferral or avoidance, resulting in greater ratepayer benefits. Rather than displacing an IOU Grid-Edge DERMS, a well-designed marketplace amplifies its effectiveness and benefits.[15]

Third, once these principles and objectives have been developed, the Commission should establish WG to address unresolved issues. CalCCA recommends that the Commission establish the following three WG: (1) DER Visibility and Data Systems; (2) TSO-DSO Operational Coordination; and (3) Market Design and Governance. These WGs should include IOUs, CCAs, third-party DER providers, Energy Division staff, CAISO staff, and other stakeholders, and be tasked with investigating challenges and proposing solutions related to deploying Enterprise and

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[15] CalCCA discusses the benefits of marketplaces in greater detail in response to Question 11(a) and (b), and in response to comments in Sections III and IV.

Grid-Edge DERMS and flexibility marketplace platforms to support DER orchestration. The WG should incorporate lessons from utility regulators, DSOs, TSOs, and marketplace operators in the UK, Australia, and other jurisdictions where demand-flexibility frameworks have been deployed. CalCCA provides additional details, including objectives and topics, in response to Question 5 below.

3. Given the time required to prepare and decide on potential IOU DER orchestration applications and the related IOU pilots currently underway, how can IOUs:

a. Ensure DER orchestration strategies and implementation stages proposed in future applications incorporate lessons learned, relevant data, and any other benefits generated from the currently ongoing pilots and the information set forth in the record of this proceeding?

CalCCA has no response at this time.

b. Coordinate the pilots with the formal DER orchestration application proceeding?

CalCCA has no response at this time.

4. What, if any, specific pre-application steps and activities related to DER orchestration, such as convening workshops or a working group process, should be completed prior to the IOUs filing of DER orchestration applications?

See CalCCA's response to Question 2 above.

5. If convening a working group or workshops is warranted, what should be the explicit objectives and key topics to address?

As discussed in response to Question 2 above, the Commission should create three separate stakeholder WG to address DER visibility and data systems, TSO-DSO operational coordination, and market design and governance. CalCCA provides recommendations for the objectives and topics for each WG below.

A. DER Visibility and Data Systems WG

The objective of this WG is to evaluate and identify potential measures, platforms, systems, and data-sharing opportunities to unlock the potential benefits of DER orchestration, including interoperability and communication protocols and standards. The evaluation should address IOU and third-party Grid Edge DERMS, IOU Advanced Distribution Management Systems (ADMS)/Enterprise DERMS, and flexibility marketplace platforms. Suggested topics to be addressed by the DER Visibility and Data Systems WG include:

- DSO and TSO DER visibility;
- Centralized and decentralized DER registries, including trust frameworks;[16]
- Data sharing platforms;
- ADMS/ Enterprise DERMS;
- IOU and aggregator Edge-DERMS;
- Flexibility marketplace platforms;
- Communication protocols and standards; and
- Interoperability requirements.

B. TSO-DSO Operational Coordination WG

The objective of this WG is to evaluate TSO-DSO coordination and DER visibility challenges, and to identify potential solutions for orchestrating DER/demand-flexibility resources, including the possible deployment of flexibility marketplaces. Topics to be addressed by the TSO-DSO Operational Coordination WG include:

- Forecasting and modeling;
- Bulk system visibility;

[16] See CalCCA's comment in Section IV for a discussion of trust frameworks. A trust framework is a set of standardized rules and procedures governing secure data sharing without the need for multiple bilateral agreements. They are low-cost, quick to deploy, and offer a high degree of security. Trust frameworks could be used to share DER asset and performance data among participants in a flexibility marketplace as an alternative to a centralized DER registry, helping ensure the data remains up-to-date and usable.

- Reliability;
- Operational coordination;
- Data access and sharing;
- Market interactions; and
- Value stacking and dual participation.

C. Market Design and Governance WG

The objective of the Market Design and Governance WG is to facilitate the development of a fair, open, and competitive demand flexibility market under various DER orchestration frameworks. The WG should also be charged with evaluating and recommending governance structures that align IOU financial motives with state policy goals, including climate change mitigation, customer rate affordability, reduced customer energization and DER interconnection times, and support for social justice/equity.

- DSO functions;
- Market operators;
- Roles of CCAs and third-party aggregators;
- Dispatch authority;
- Marketplace structures;
- Aligning IOU financial motivations with state policy goals; and
- Oversight and monitoring.

6. Parties provided recommendations on regulatory pathways. Please provide feedback on the recommended regulatory pathways or provide alternative proposals.

As discussed in greater detail in CalCCA's response to Question 2 above, the Commission should first adopt guiding principles, including the proposed principles for establishing effective governance and fair and competitive market opportunities. Next, the Commission should adopt a holistic approach to evaluating DER orchestration, encompassing multiple use cases and a potential marketplace, to accelerate the growth of demand flexibility.

The Commission should establish WG to address the many unresolved issues, including data architecture, operational roles, and market structures. Only after these steps have been completed should the Commission determine the appropriate regulatory pathway for implementation of a DER orchestration framework.

7. Of the six key discussion topic areas identified during Workshop 1 for developing a DER orchestration framework, which topics or subtopics are best suited for development through stakeholder working groups or future workshops?

In addition to the key topics listed in CalCCA's response to Question 5 above, the following discussion topics from WS 1 are best suited for development through the stakeholder WG recommended above:

- Open, Interoperable Communications for DER Visibility;
- Dispatch Mechanisms and Aggregator Roles;
- Cost-Benefit Methodologies and Valuation Frameworks;
- Incentive Structures and Mechanisms; and
- Grid Services and Use Cases.

Other topics, including IOU readiness and scalability, should be addressed later, since they depend on the established framework.

8. How should the Commission and/or IOUs ensure engagement with California Tribal Nations, environmental social justice communities, and other communities that may be impacted by implementation of the DER orchestration framework that may not be tracking the current proceeding, or have capacity to engage on the highly technical aspects of the proceeding?

CalCCA has no response at this time.

9. Regarding PG&E's Workshop 1 presentation, when implementing the primary use cases described under Key Topic #1 (system peak reduction, speed to power, and resource-efficient grid investments), are these the correct use cases to implement? If so, which use cases should be implemented first, and which should be implemented in parallel or sequentially?

DER orchestration can serve all of the use cases identified by PG&E (system peak reduction, speed to power, and resource-efficient grid investments). These three use cases can be implemented in parallel. However, emphasis should be placed on developing a framework to employ DER orchestration as a planning-grade grid resource to avoid or defer grid investments, since DERs are already being used to reduce system peak and accelerate customer energization.

10. How should the Commission coordinate DER orchestration implementation for IOUs in different stages of technical readiness with regards to telemetry, DER management systems, and other DER orchestration aspects?

As discussed in CalCCA's response to Question 2 above, the Commission should first adopt a robust set of guiding principles, including establishing governance structures, then evaluate DER orchestration frameworks and possible use cases using a holistic approach. Finally, the Commission should establish WG to address unresolved issues related to data access, interoperability, communications, TSO-DSO coordination, and market access before attempting to coordinate the implementation of DER orchestration across IOUs in different stages of technical readiness.

The results of these three efforts will provide guidance on the IOUs' development of their DERMS system, telemetry, and other technical aspects related to the specific framework that is adopted. If, for example, the IOU Grid-Edge DERMS will be used to publicize flexibility needs and offers through a flexibility marketplace platform, it could impact how and to what extent the IOUs develop telemetry and interoperability requirements. A marketplace, which could be deployed statewide or within each IOU's service area, would reduce the number of resources that must be directly connected to the IOU Grid-Edge DERMS, potentially affecting the design of the IOUs' systems.

Once these three steps are completed, the Commission will have a much clearer picture of the IOUs' technical readiness to support the adopted DER orchestration framework. Until this has been accomplished, it is premature for the Commission to attempt to coordinate technical readiness among the three IOUs.

11. How can current AMI 1.0 and next-generation AMI 2.0 Grid Edge DERMs capabilities support IOU-led DSO DER orchestration programs?

CalCCA has no response to the question regarding AMI 1.0 and AMI 2.0 Grid-Edge DERMS capabilities, but provides responses to Questions 11(a) and (b) below.

a. What additional communications or technical capabilities are necessary to enable reliable dispatch and settlement of DERs via Grid Edge DERMs?

As CalCCA has discussed in prior Comments, the Commission should consider adopting Open Automated Demand Response (OpenADR) as the communications protocol for the IOU Grid-Edge DERMS.[17] The IOUs already use OpenADR for many of their demand response programs, and the protocol is cloud-based and well-suited for scaling.[18] As discussed in more detail in its responses to Question 11(b) and in Section III, the Commission should evaluate the potential costs and benefits of deploying flexibility marketplaces in conjunction with the IOU Grid-Edge DERMS to scale the participation of non-IOU-managed DERs and increase ratepayer benefits. A marketplace platform would communicate with the IOUs' Grid-Edge DERMS using the IOUs' preferred protocol, but could also support other communication protocols for managing enrolled demand flexibility providers. This approach would enable the IOUs to use their preferred communications protocols and could provide aggregators, CCAs, and customer-owned DERs with a lower-cost communications option.

b. What are differences in capabilities, advantages, and disadvantages of Grid Edge DERMs compared to centralized Enterprise DERMs for enabling IOU-led DSO DER orchestration?

Enterprise DERMS, also called Grid DERMS, are tightly integrated with the utility's ADMS and other grid management platforms. They are typically designed to manage IOU-

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17 *See, e.g., CalCCA's Opening Comments on Assigned Commissioner's Ruling Seeking Additional Information on DER Enabled Near Term Flexible Connections*, R.21-06-017 (Dec. 19, 2025), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M591/K672/591672890.PDF.

18 *Id*. at 5-6.

owned or contracted DERs and rely on IOU power flow modeling to dispatch resources.[19] Since they are integrated with the IOUs' enterprise systems, they sit behind the IOU firewall and typically require more expensive communications options for the resources that they control.[20] These factors also make them less scalable than a Grid-Edge DERMS.

Grid-Edge DERMS are specifically designed to monitor and control customer-owned DER via price and dispatch signals to third-party and CCA-managed DERMS. They rely on lower-cost cloud-based systems to communicate with customer-owned DERs, enabling them to scale more easily. Because they are located beyond the IOU firewalls, they lack the grid visibility that Enterprise DERMS provide. Increasingly, utilities are deploying Grid-Edge and Enterprise DERMS together to leverage the advantages of both.

Achieving the full benefits of DER orchestration requires robust participation from a large pool of DER providers. Flexibility marketplace platforms complement IOU Grid-Edge DERMS by providing a centralized platform that more easily facilitates transactions between IOUs and flexibility providers. Rather than entering into contracts or participating in individual IOU tariffs or programs, flexibility providers would only need to register and be pre-qualified by the marketplace operator, which in turn matches resources with needs tendered by the IOUs via their Grid-Edge DERMS. This greatly simplifies participation and increases the number of DERs available to provide flexibility services.

The Commission should investigate the development of flexibility marketplaces as a means of significantly scaling DER participation and of unlocking greater ratepayer value. These

[19] Astrid Atkinson, "What is Grid Orchestration and how does it differ from DERMS?," *Camus Energy*, https://www.camus.energy/gridorchestration#Air-Traffic.

[20] Amber Mullaney, "The Difference Between Grid-Edge DERMS and Grid DERMS," *Virtual Peaker*, 7 Aug. 2024, https://virtual-peaker.com/blog/the-difference-between-grid-edge-derms-grid-derms/.

marketplaces can either be centralized and independently run or provided as Software-as-a-Service (SaaS) under contract with the IOU. Regardless of the framework, the Commission should also investigate measures to align the IOUs' financial motivations with state policy goals for carbon reduction and rate affordability, ensuring that they prioritize demand flexibility over grid asset investments. The ultimate success of any DER orchestration framework depends on whether, and to what extent, the IOUs maximize opportunities to leverage demand flexibility from DERs to defer or avoid grid investments.

12. What customer-owned DER technologies (e.g., EVs, smart thermostats, water heaters, batteries, other flexible loads) are currently capable of and/or best fits for participating in IOU-led DSO DER orchestration programs to provide value to ratepayers?

a. What technical or operational barriers remain for broader participation?

The current dual participation rules, which are set on an ad hoc basis, pose a barrier to broader participation in a DER orchestration construct. The Commission should ensure that robust dual participation policies are developed under the Demand Response Proceeding[21] to enable broad customer participation in DER orchestration and to maximize the value it can provide through value stacking.

Additionally, there is currently no framework for IOU DSOs to provide clear, transparent signals, tied to grid value, to third-party and CCA-managed DERs to provide distribution grid constraint management. This is also a major barrier to broader participation in DER orchestration, which could be resolved by deploying a flexibility marketplace, as previously discussed. The Commission should clearly define the role of IOUs, acting as DER orchestrators, in providing demand-flexibility signals and compensating DER providers for these services.

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21 *See generally*, *Order Instituting Rulemaking to Enhance Demand Response in California* (Demand Response Proceeding), R.25-09-004 (Sept. 18, 2025), https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:R2509004.

Additionally, the Commission should establish appropriate guardrails to ensure open access to markets, transparent rules for resource selection and dispatch, and fair and accurate settlements. This issue should be addressed in the Market Design and Governance WG, as discussed in CalCCA's response to Question 4 above.

13. What requirements should be established to enable reliable integration of customer-owned DERs into IOU DER orchestration programs?

As discussed in response to Question 2 above, and in comments in Sections III and IV below, CalCCA believes that flexibility marketplace platforms provide the most effective, scalable, and cost-effective means of matching non-IOU-owned or managed DERs with flexibility needs. While IOU Grid-Edge DERMS can orchestrate customer-owned DERs, either directly or through CCAs and third-party aggregators, the technical requirements of transactions may discourage participation. Under an IOU Grid-Edge DERMS, customers and aggregators may be required to participate via individual programs, tariffs, or under bilateral agreements, potentially limiting value-stacking opportunities. From the IOU's perspective, it would need to enroll enough DERs at specific locations to enable grid deferral opportunities.

A marketplace platform, on the other hand, provides the IOUs with access to a significantly larger pool of DERs managed by CCAs or third-party aggregators. The marketplace pre-qualifies DER assets and flexibility providers, supports multiple transactions and use cases, creates value-stacking opportunities, and handles settlement and verification. These functions reduce the transactional burden on both DER providers and IOUs. The Commission should direct the WGs to evaluate these potential benefits and their associated costs before establishing requirements for an IOU Grid-Edge DERMS as the primary means of orchestrating DERs.

a. How should IOUs account for customer behavior and resource availability when determining the dependability of orchestrated DERs on the distribution grid?

See CalCCA's response to Question 13 above.

14. How should circuit-level demand flexibility be modeled by IOU DSOs to better inform how distribution planning investments should be allocated in future planning cycles?

CalCCA has no response at this time.

15. In PG&E's opening comments on the Assigned Commissioner's Ruling Issuing Questions on the Electrification Impact Study Part 2 Final Reports, PG&E stated that "the EPIC 4.08 pilot is intended to improve how load flexibility is represented in scenario planning by helping translate flexible load potential into inputs that can be assessed in" distribution system investment plans. What, if any, learnings from PG&E's EPIC 4.08 pilot and its ongoing development can be used to model load flexibility into the annual Distribution Planning and Electrification Process (DPEP) and how would that be accomplished?

CalCCA has no response at this time.

16. The DSO ensures that the system is operated in a safe, reliable manner and is responsible for optimizing system performance. What components are needed for a DER orchestration framework that will ensure these operations continue while also allowing for the flexibility needed to manage load that incorporates a high level of DERs?

The Commission must ensure that any adopted DER orchestration framework prioritizes the safe, reliable operation of the distribution system with increasing levels of DER participation. However, the WS Reports demonstrate that stakeholders are far from reaching consensus on many components of a DER orchestration framework, including how to maintain safe and reliable grid operations. This critical question should be thoroughly explored through the stakeholder WG processes described in CalCCA's response to Questions 2 and 5 above.

17. The IOUs have previously made statements regarding opportunities for lowering costs. Please provide explicit examples of these opportunities including how these opportunities may shift between initial implementation and further scaling.

As discussed in its response to Questions 11(a) and (b) above and comments in Section III below, the Commission should investigate the deployment of a flexibility marketplace in coordination with IOU Grid-Edge DERMS. Marketplaces have the potential to unlock greater value for ratepayers and the grid by reducing barriers and costs for non-IOU-managed flexible resources, thereby expanding the pool of available resources. Limiting the framework to IOU Enterprise or Grid-Edge DERMS will discourage participation and significantly reduce potential ratepayer and grid benefits.

18. Are there any other relevant issues not discussed in the March 23 Assigned Commissioner's Ruling, but brought up in the workshops that the Commission should consider for the DER orchestration application process?

See CalCCA's response to Question 2 above, and its comments in Sections III and IV below.

III. CALCCA'S COMMENTS ON THE TRACK 2 WS REPORT: DISTRIBUTION SYSTEM OPERATOR DER ORCHESTRATION, WS DATE MAY 21, 2026

While the DER Orchestration WS Report captures several of the points CalCCA made during its presentation at the WS, it should be revised to better reflect CalCCA's positions on the unresolved issues in Track 2, including the "build versus buy" bias inherent in the existing utility business model. The DER Orchestration WS Report should also be revised to better reflect CalCCA's positions on the need for additional record building in Track 2 of this proceeding, including the recommendation that the Commission first adopt guiding principles to inform the development of a DSO-led DER orchestration framework.

CalCCA also clarifies its position on flexibility marketplaces, which could not be fully articulated during the DER Orchestration WS due to time constraints. Flexibility markets can exist as an independent, centralized entity that matches grid needs tendered by DSOs and flexibility resources that have been pre-qualified and registered with the marketplace operator. Marketplace providers can also contract directly with a DSO under a SaaS arrangement. Under either approach, the marketplace operator is providing a transactional platform through which flexibility needs and vendors are matched. The DSO plays an active and important role regardless of the structure, identifying the needs, setting the transactional criteria, and sending dispatch signals, typically via a Grid-Edge DERMS platform. Hence, both of these structures fit under the context of a DSO-led DER orchestration framework.

The purpose of the marketplace is to facilitate transactions and provide the DSO access to a significantly larger pool of DERs, creating more value for the DSO, ratepayers, and DER providers.[22] A flexibility marketplace leverages cloud-based communications to lower participation costs and achieve greater scale than would be possible under an IOU DERMS system alone. More precisely, the IOU Grid-Edge DERMS approach would require DER providers to enroll in programs, contracts, or tariffs, which are essentially bilateral transactions. A marketplace, on the other hand, provides a single platform for DSOs and DER providers, reducing transactional costs. It can also support long (grid deferral/avoidance), medium (bridging solutions, resource adequacy), and short-term (intraday/real-time grid support) transactions.[23]

IV. CALCCA'S COMMENTS ON THE TRACK 2 WS REPORT: TSO-DSO COORDINATION, WS DATE JUNE 5, 2026

While the TSO-DSO Coordination WS Report presented a high-level overview of the WS, it did not include Piclo's discussion of trust frameworks in the context of DER asset registries. During its presentation, Piclo highlighted the fact that, in its experience operating in markets around the world, nearly every statewide or countrywide DER registry has failed to deliver value over time.[24] In describing the potential value of DER asset registries, Piclo emphasized the need for high-resolution data, including each asset's availability for dispatch beyond existing operational commitments. However, unless this data is tied to a value (monetary or nonmonetary), asset owners have little incentive to keep this data up to date, and the DER

22 TSO-DSO Coordination WS Report, at 132.
23 *Id*. at 130.
24 TSO-DSO WS Recording, starting at 2:50.

registry becomes stale and unusable. Piclo later described the UK's move towards trust frameworks that govern coordinated data sharing among various market and other platforms within a decentralized structure.[25] Trust frameworks, which are used extensively in the financial, healthcare, and other industries that require secure data sharing,[26] offer an alternative to a centralized, statewide registry and reduce the risk of data becoming stale.

Regardless of the DER orchestration framework adopted, the Commission should consider Piclo's experience with centralized DER registries and the risk of data becoming stale. Specifically, the Commission should investigate a decentralized data-sharing schema that relies on secure data exchanges within a trust framework and ensure that any DER asset database has a clear purpose and is tied to some form of value creation for the asset owner or manager. This value could be compensation for providing verified grid services or for early energization on constrained circuits under an FSC mechanism as contemplated in Track 2.

V. 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,

Leanne Bober

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

July 27, 2026

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25 *Id*. starting at 3:13.

26 *See, e.g.*, "*Trustwork Framework*," Icebreaker One Limited, https://ib1.org/definitions/trust-framework/.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION EXTENDING THE ARREARAGE MANAGEMENT PLAN PROGRAM UNTIL FEBRUARY 1, 2027

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July 30, 2026

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California Public Utilities Commission Proceedings

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends that the Commission:

- Adopt the Proposed Decision extending the sunset date of the AMP from October 1, 2026, to February 1, 2027, to minimize customer disruption and confusion, align the AMP sunset date with the PIPP's sunset date, and allow the Commission more time to deliberate on the potential extension of both programs.

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 Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION EXTENDING THE ARREARAGE MANAGEMENT PLAN PROGRAM UNTIL FEBRUARY 1, 2027

The California Community Choice Association[2] (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[3] on the proposed *Decision Extending the Arrearage Management Payment Plan Program Until February 1, 2027*[4] (Proposed Decision), dated July 10, 2026.

I. THE PROPOSED DECISION EXTENDING THE AMP SUNSET DATE TO FEBRUARY 1, 2027, TO ALLOW THE COMMISSION MORE TIME TO DELIBERATE AND MINIMIZE CUSTOMER DISRUPTION AND CONFUSION SHOULD BE ADOPTED

The Proposed Decision to extend the Arrearage Management Program (AMP) until February 1, 2027, should be adopted. The Proposed Decision points out that the AMP is

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[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*, https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

[4] Proposed *Decision Extending the Arrearage Management Payment Plan Program Until February 1, 2027*, Rulemaking (R.) 18-07-005 (July 10, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M610/K356/610356276.PDF.

scheduled to sunset on October 1, 2026, but the Commission has yet to decide whether to extend the AMP. Extending the AMP to February 1, 2027, and aligning its sunset date with the sunset date of the Percentage of Income Payment Plan Pilot Program (PIPP) is a simple solution with low administrative burden. The additional time will allow the Commission time to deliberate over extending the AMP and/or PIPP, while preventing the customer disruption and confusion of the AMP temporarily terminating even if the Commission ultimately extends the program.[5] As CalCCA has argued in previous comments, the AMP provides much-needed assistance to customers struggling to pay down their arrearages and should be established as a permanent program.[6] The Commission should adopt the Proposed Decision's proposal to extend the AMP from October 1, 2026, to February 1, 2027.

II. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and respectfully requests adoption of the recommendations proposed herein.

Respectfully submitted,

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

July 30, 2026

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5 Proposed Decision, at 4 (describing the impacts of allowing the AMP to sunset before the Commission has decided on whether to extend the program).

6 *See California Community Choice Association's Opening Comments on Assigned Commissioner's Ruling Setting Workshop and Ordering Comments*, R.18-07-005 (Mar. 25, 2026), at 11 (recommending the Commission establish the AMP as a permanent program), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K529/603529083.PDF.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering	R.14-07-002
And Related Matters.	Application 16-07-015

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF PROGRAM REPORT
APRIL 1, 2026 TO JUNE 30, 2026 FOR MARIN CLEAN ENERGY

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July 30, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering	R.14-07-002
And Related Matters.	Application 16-07-015

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF PROGRAM REPORT
APRIL 1, 2026 TO JUNE 30, 2026 FOR MARIN CLEAN ENERGY

Marin Clean Energy ("MCE") submits this Disadvantaged Communities Green Tariff ("DAC-GT") quarterly report in accordance with Resolution E-4999, issued June 3, 2019. Ordering Paragraph ("OP") 1(f) of Resolution E-4999 states:

> "Once an IOU has completed its first RFO or initiated customer enrollment, whichever occurs first, within 30 Calendar Days after the end of each calendar quarter, PG&E, SCE, and SDG&E shall file a report in R.14-07-002, or a successor proceeding, and serve the same report on that service list, for the previous quarter and cumulatively, with the following minimum information for the DAC-GT and CSGT programs: capacity procured, capacity online, and customers subscribed. The quarterly reports should also identify the DACs in which DAC-GT or CSGT project is located and list the number of customers participating in each program in each DAC within a utility's service territory. Finally, the quarterly reports must include the number of customers who have successfully enrolled in CARE and

FERA in the process of signing up for the DAC-GT or CSGT programs."[1]

As program administrators, CCAs are subject to the same reporting requirements as investor-owned utilities ("IOUs"). Accordingly, MCE hereby submits this quarterly report for DAC-GT covering the period of April 1, 2026 to June 30, 2026, attached hereto as Attachment A. Per D.24-05-065,[2] the CSGT program is closed for further procurement. MCE has not procured a CSGT project to date and has closed its CSGT program.

Respectfully submitted,

/s/ *Rachel Dec*

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July 30, 2026

[1] Resolution E-4999, Pursuant to Decision 18-06-027, Approving with Modification, Tariffs to Implement the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs, p. 63, OP 1(f).
[2] Decision 24-06-065, Decision Modifying Green Access Program Tariffs and Adopting A Community Renewable Energy Program, issued May 30, 2024, p. 169.

ATTACHMENT A

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF PROGRAM REPORT
APRIL 1, 2026 TO JUNE 30, 2026

Pursuant to Decision 18-06-027 ("Decision")[3] and in accordance with Resolution E-4999,[4] Marin Clean Energy ("MCE") files this quarterly report on the Disadvantaged Communities Green Tariff ("DAC-GT") program for the period April 1, 2026 to June 30, 2026. MCE reports on the following program metrics as required by Resolution E-4999:

1. Capacity procured and online;
2. Participating customers, including breakdown by Disadvantaged Community ("DAC");
3. California Alternate Rates for Energy ("CARE") and Family Electric Rate Assistance ("FERA") enrollment.[5]

1. Capacity Procured and Online

The DAC-GT program (branded as MCE's "Green Access" program) has a capacity cap of 4.64 MW. D.24-05-065 allocates an additional 3.609 MW to the program, for a total cap of approximately 8.25 MW[6].

On August 27, 2021, MCE launched the first DAC-GT and CSGT solicitation, with bids due on November 19, 2021. MCE received bids for the DAC-GT program and signed PPAs to fill the total program capacity (4.64 MW). In March of 2023, the developer notified MCE that it would be unable to perform under the requirements of Conflitti PPA 2 after receiving results of the project's interconnection studies and permitting requirements, requiring modifications to the commercial operation date and price. Upon receiving the permitting and interconnection results, the developer requested a price increase for both Conflitti PPA 1 and Conflitti PPA 2. MCE negotiated with the developer to reduce the requested price increase. The developer indicated that without the negotiated price increase, it would be unable to perform under Conflitti PPA 2.

MCE performed due diligence with respect to the proposed amendments. MCE confirmed that the developer's requested price increase is below the Commission-determined price cap for DAC-GT projects. The developer's requested price increase is competitive with bids received by MCE for its 2021 DAC-GT RFO. The increased contract price requested by the developer is lower than the contract prices in all other offers MCE received in the 2021 DAC-GT solicitation. MCE determined it would be prudent and reasonable to accept the price increase and avoid the administrative cost of going back out to market as well as the higher anticipated price of offers.

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[3] Decision 18-06-027, Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities, issued June 22, 2018, p. 55.
[4] Resolution E-4999, p. 40 and p. 63, OP 1(f).
[5] Resolution E-4999, OP 1(f).
[6] D.24-05-065, p. 138 and p. 170, OP 3(e).

In exchange for the negotiated price increase and COD extension, MCE negotiated that the developer must pursue the new Low Income ITC Bonus to negate the price increase. MCE also negotiated a doubling of both the Development and Performance Security of the projects.

MCE's Board of Directors reviewed the negotiated amendments to the Conflitti PPAs during its October 6, 2023 Technical Committee meeting and approved the execution of the Amendments. The amendments were executed on October 13, 2023 and submitted to the CPUC for Energy Division approval on October 24, 2023[7]. The Advice Letter was approved by the CPUC on January 31, 2024, effective November 24, 2023.

After the approval of the October 13, 2023 amendments, the counterparty learned that their financing entity had decided not to move forward after the amendments were signed. This required the developer to go back out to market for replacement financing. The developer was able to final alternate financing, but at higher financing costs which caused the projects to no longer be economically feasible at the compensation provided under the PPA. The developer requested another price increase for Conflitti 1 and Conflitti 2. After performing due diligence and determining that the increased price was reasonable and in line with market prices, MCE granted the price increase and further extensions of the construction schedule. MCE executed the additional amendments on May 3, 2024. MCE submitted the amendments to the CPUC for Energy Division approval on May 20, 2024[8]. The Advice Letter was approved by the CPUC on June 24, 2024, effective June 19, 2024. Conflitti 1 and Conflitti 2 are both now complete, entering commercial operations on January 27, 2026.

MCE's DAC-GT program was allocated an additional 3.609 MW of capacity in 2024. To procure resources for this additional capacity, MCE launched a solicitation on February 23, 2026 for solar generation and/or solar generation paired with energy storage. The submission deadline was April 3, 2026. MCE received bids from multiple developers and is currently engaged in commercial negotiations with preferred projects to fulfill the program's capacity allocation.

MCE is serving the expanded capacity of DAC-GT customers with solar generation from an interim resource, the Goose Lake project, located at 15004 Corcoran Rd., Lost Hills, CA 93249 in DAC census tract 6031001300, in accordance with Resolution E-4999.[9].

2. Participating Customers

The DAC-GT program provides a 20% bill discount to eligible customers located in DACs. DACs are defined under D.18-06-027 as communities that are identified in the CalEnviroScreen ("CES") tool as among the top 25 percent of census tracts statewide, plus the census tracts in the highest

[7] Advice Letter MCE 71-E
[8] Advice Letter MCE 76-E.
[9] Resolution E-4999, p. 24 and p. 63 OP 1(i), permits PAs to serve DAC-GT customers through existing eligible resources that meet all other DAC-GT program rules on an interim basis, until new DAC-GT projects are interconnected.

five percent of CES' Pollution Burden that do not have an overall CES score because of unreliable socioeconomic or health data.[10]

The DAC-GT program is available to residential customers who live in DACs, receive generation service from MCE, and meet the income eligibility requirements for the CARE program and/or the FERA program.[11] In MCE AL 42-E-A, MCE opted to auto-enroll eligible customers that live in one of the top 10% of DAC census tracts statewide in MCE's service area if they meet certain criteria.[12]

Table 1 sets forth, for each program, the number of customers participating in each program to date. As noted above, participating customers under the DAC-GT program are being served by interim resources.

Table 1: Participating Customers in DAC-GT and Program

	DAC-GT	
Customers Subscribed as of 6/30/2026	5,611	

Table 2 indicates the number of customers participating in the DAC-GT program grouped by DAC census tract number.

Table 2: Participating Customers in DAC-GT by DAC Census Tract

Census Tract	County	City (closest by proximity)	Count
6013309000	Contra Costa	Pittsburg	46
6013310000	Contra Costa	Pittsburg	320
6013311000	Contra Costa	Pittsburg	452
6013312000	Contra Costa	Pittsburg	179
6013313101	Contra Costa	Pittsburg	252
6013313204	Contra Costa	Pittsburg	7

[10] D.18-06-027, p. 16 and p. 96, Conclusion of Law 3.
[11] D.18-06-027, p. 51.
[12] MCE AL 42-E-A, p. 3.

6013313206	Contra Costa	Pittsburg	1
6013314102	Contra Costa	Pittsburg	13
6013314103	Contra Costa	Pittsburg	4
6013314104	Contra Costa	Pittsburg	68
6013314200	Contra Costa	Pittsburg	495
6013315000	Contra Costa	Pittsburg	9
6013327000	Contra Costa	Concord	10
6013358000	Contra Costa	Rodeo	44
6013365002	Contra Costa	Richmond	327
6013366002	Contra Costa	San Pablo	10
6013373000	Contra Costa	Richmond	10
6013374000	Contra Costa	Richmond	2
6013375000	Contra Costa	Richmond	58
6013376000	Contra Costa	Richmond	410
6013377000	Contra Costa	Richmond	565
6013378000	Contra Costa	Richmond	14
6013379000	Contra Costa	Richmond	472
6013380000	Contra Costa	Richmond	17
6013381000	Contra Costa	Richmond	453
6013382000	Contra Costa	Richmond	289
6013383000	Contra Costa	Richmond	1
6013386000	Contra Costa	Richmond	8
6095250701	Solano	Vallejo	188
6095250801	Solano	Vallejo	3
6095250900	Solano	Vallejo	297

6095251000	Solano	Vallejo	16
6095251200	Solano	Vallejo	21
6095251300	Solano	Vallejo	0
6095251400	Solano	Vallejo	1
6095251500	Solano	Vallejo	24
6095251600	Solano	Vallejo	23
6095251802	Solano	Vallejo	124
6095251901	Solano	Fairfield	21
6095251902	Solano	Vallejo	22
6095252305	Solano	Fairfield	1
6095252402	Solano	Fairfield	326
6095252502	Solano	Fairfield	7
6095253500	Solano	Suisun City	1
Grand Total			**5,611**

3. CARE and FERA Customer Enrollments

MCE auto-enrolled its customers in the DAC-GT program. To date, no CARE/FERA enrollment occurred as a result of the DAC-GT or CS-GT enrollment for customers in MCE's service area.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update Rules for the Safety, Reliability, and Resiliency of Electrical Distribution Systems.	Rulemaking 24-05-023 (Filed May 30, 2024)

JOINT LOCAL GOVERNMENTS AND JOINT CCAS' COMMENTS ON THE PROPOSED DECISION

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Dated: July 30, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update Rules for the Safety, Reliability, and Resiliency of Electrical Distribution Systems.	Rulemaking 24-05-023 (Filed May 30, 2024)

JOINT LOCAL GOVERNMENTS AND JOINT CCAS' COMMENTS ON THE PROPOSED DECISION

In accordance with Rule 14.3 of the Commission's Rules of Practice and Procedure, the Counties of Napa, San Luis Obispo, and Sonoma (the Joint Local Governments), and Marin Clean Energy and Pioneer Community Energy (the Joint CCAs) submit these comments on the proposed decision adopting a unified investor-owned utility customer reliability report. The proposed reporting template appears structured to provide the Commission with a fair amount of information about utility outages, though it remains to be seen whether reporting on outages will translate to Commission or utility action that improves reliability. The proposed decision's primary shortcoming, however, is that it closes the proceeding prematurely. The Commission must leave R.24-05-023 open to address the practical questions about protective equipment configuration, outage prioritization, and repetitive outage remediation identified in the rulemaking and reserved for later tracks of the proceeding. The Commission should also require the utilities to submit an interim report by no later than December 2026 to help inform future tracks of the proceeding and confirm that the report framework will provide information necessary to support reliability improvements.

I. THE PROCEEDING MUST REMAIN OPEN

The Joint Local Governments and Joint CCAs oppose the proposed closure of this proceeding after Track 1 when the Track 2 issues remain unaddressed. Closure is inconsistent with the scoping memo and with stakeholder expectations.

The scoping memo stated that "[t]his proceeding will be conducted in several tracks, with each track considering discrete issues identified within the scope of the proceeding. Subsequent rulings will provide the scope and schedule of each track."[1] Track 1, which focused on producing the outage reporting template, was intended to "build the foundation to establish parameters and rules for increased outage transparency for customers."[2] But Track 1 was never intended to be the only track. The Order Instituting Rulemaking identifies a number of issues that are critical to addressing the ongoing degradation of electric reliability in the large utilities' service territories. Distribution system risk analysis and response was intended to assess whether the current planning process properly assesses the risk to distribution services and whether the utilities' response and recovery plans match their risk assessment.[3] Support for short-term reliability, safety, and system resiliency was intended to examine whether the Commission should modify or establish any new rules, standards, or requirements to ensure that the utilities are providing reliable service while stressing the need for increased distribution infrastructure system resilience in the face of a changing risk landscape. As part of this issue, the Commission would examine the configuration of protective equipment and whether additional rules or standards are necessary, prioritization of outages and whether the utilities should triage outages based on certain criteria, and whether the utilities should be required to provide additional information on infrastructure subject to repeated outages and take remedial action for that infrastructure.[4] These issues are critical to the on-the-ground experience of the large utilities'

[1] Assigned Commissioner's Scoping Memo and Ruling, p. 5.

[2] *Id.* at p. 3.

[3] Order Instituting Rulemaking, pp. 5–6, preliminary issue 1(c).

[4] *Id.* pp. 6–7, issue 3.

customers.

The Joint Local Governments and Joint CCAs have argued for years that the decline in electric reliability, driven largely by PG&E's fast-trip outage program, is a significant issue that cannot go unaddressed. Wildfire-mitigation outages, whether de-energizations or fast-trip, have compounding negative effects on affected customers and communities. The new outage reporting template may help the Commission gain a better understanding of the scope and impact of the utilities' reliability issues, but data alone will not address the real-life impacts of the outages. Moreover, the Commission does not need to wait for the first iteration of the new outage reports in mid-2027 to understand the scope and scale of PG&E's fast-trip outage program, which is subject to monthly reports that provide a significant amount of information regarding affected circuits, vulnerable customers, and critical facilities. As Sonoma and Napa detailed in their opening comments on the Order Instituting Rulemaking, in 2023, 1.97 million PG&E customer accounts (726,708 unique customers) experienced fast-trip outages, with 50 circuits experiencing 10 or more outages (two circuits experienced 24 outages and one circuit experienced 29).[5] Two years later, as of November 30, 2025, PG&E's fast-trip outages had affected 1.82 million customer accounts (838,925 unique customers), with 46 circuits experiencing 10 or more outages (and one experiencing 30 outages).[6] The Commission planned to examine the utilities' reliability issues and consider ordering remedial measures when it opened this proceeding two years ago. The outages have continued apace in the intervening years with no corresponding regulatory action.

It would also be inadvisable to close this proceeding before the utilities' first report is

[5] Opening Comments of Napa and Sonoma Counties on the Order Instituting Rulemaking, pp. 3–4.

[6] PG&E–EPSS Monthly Report, Excel Spreadsheet, Tab Summary, Tab YTD EPSS Outages Circuit (December 15, 2025)

submitted, as it may be necessary to make changes to the reporting framework before the three-year cycle of utility advice letters begins in mid-2029. If the Commission is serious about addressing utility reliability issues, it cannot be complacent about the information it is receiving from the utilities. An interim report, submitted no later than December 2026, but ideally earlier, would also be valuable in helping to shape future tracks of the proceeding.

II. CONCLUSION

The Commission must leave this proceeding open to address the on-the-ground reliability improvements it identified in the original rulemaking. It is not enough for this proceeding to adopt a new outage reporting template with no near-term action based on the significant amount of outage data already available. The proposed decision must be modified to address the start of Track 2.

Dated: July 30, 2026

Respectfully submitted,

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**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 REPLY COMMENTS ON ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGE'S RULING ISSUING QUESTIONS ON THE DISTRIBUTED ENERGY RESOURCES ORCHESTRATION WORKSHOP REPORTS

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July 31, 2026

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SUMMARY OF RECOMMENDATIONS[1]

In response to party Opening Comments, the Commission should:

- Evaluate marketplace mechanisms to address the technical and operational barriers identified in the IOUs' Opening Comments; and
- Only authorize IOU pilots that include CCA-managed DERs, are time-limited, and that focus on demonstrating IOU Grid-Edge DERMS technical and operational capabilities to avoid unnecessary delays in deploying a marketplace mechanism.

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 Energy Resource Future.	R.21-06-017

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGE'S RULING ISSUING QUESTIONS ON THE DISTRIBUTED ENERGY RESOURCES ORCHESTRATION WORKSHOP REPORTS

California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to the Assigned Commissioner's and Administrative Law Judge's Ruling Issuing Questions on the Distributed Energy Resources Orchestration Workshop (WS) Reports[3] (WS Reports Ruling), dated July 9, 2026.

I. INTRODUCTION

Opening Comments[4] by the investor-owned utilities[5] (IOUs) identify technical and operational barriers to the widespread deployment of a distributed energy resource (DER) orchestration framework. The IOUs' Opening Comments call for developing early-stage

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[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] *Assigned Commissioner's and Administrative Law Judge's Ruling Issuing Questions on the Distributed Energy Resources Orchestration Workshop Reports*, Rulemaking (R.) 21-06-017 (July 9, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M610/K354/610354178.PDF.

[4] Opening Comments refer to party opening comments on the WS Reports Ruling submitted in this proceeding on or about July 27, 2026.

[5] As used herein, "IOUs" refer collectively to Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE).

demonstrations and pilot programs to address some of these perceived barriers, leveraging IOU Enterprise or Grid-Edge DER Management Systems (DERMS). While CalCCA agrees that pilots and demonstration projects provide learning opportunities, the IOUs' singular reliance on deploying multiple pilots and/or demonstration programs built around their DERMS platforms may delay the potential benefits of a demand flexibility marketplace and the rollout of a comprehensive DER orchestration framework. Working groups, such as those proposed in CalCCA's Opening Comments,[6] should be established while any pilots and/or demonstration programs are pursued to continue discussions around the final DER orchestration framework and a demand flexibility marketplace. Additionally, the Commission should ensure that CCA-managed DERs are explicitly eligible and included within the IOUs' proposed pilots and demonstration programs.

As CalCCA stated in Opening Comments,[7] many of the technical and operational barriers identified by the IOUs can be addressed more efficiently and effectively by deploying a demand flexibility marketplace that works in conjunction with IOU DERMS. Marketplaces are well suited to scaling demand flexibility, which is critical to the success of any DER orchestration framework. Any pilots or demonstrations should be limited in duration and focused on resolving technical issues related to IOU DERMS communications, including interoperability with CCAs and non-IOU-managed DERs. The California Public Utilities Commission (Commission) should therefore evaluate the deployment of a marketplace in concert with IOU Grid-Edge DERMS and authorize limited-duration, targeted demonstration programs that include CCA-managed DERs.

In response to party Opening Comments, the Commission should therefore:

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6 CalCCA Opening Comments, at 6-9.
7 CalCCA Opening Comments, at 11-19.

- Evaluate marketplace mechanisms to address the technical and operational barriers identified in the IOUs' Opening Comments; and
- Only authorize IOU pilots that include CCA-managed DERs, are time-limited, and that focus on demonstrating IOU Grid-Edge DERMS technical and operational capabilities to avoid unnecessary delays in deploying a marketplace mechanism.

II. MARKETPLACE MECHANISMS SHOULD BE EVALUATED TO ADDRESS TECHNICAL AND OPERATIONAL BARRIERS IDENTIFIED IN THE IOUS' OPENING COMMENTS

The Commission should evaluate marketplace mechanisms to address the barriers to scaling customer-owned DER participation in orchestration efforts identified in the IOUs' Opening Comments. As set forth below, the barriers described in SDG&E's and SCE's Opening Comments demonstrate the need for flexibility markets, which are well-suited to addressing many of these issues. Also as discussed below, PG&E identifies technical and operational barriers in its Opening Comments, but seems to acknowledge the potential value of market-based solutions to overcome them.

In response to Ruling Question 12(a), which asks about the technical and operational barriers that inhibit the broader participation of customer-owned DER, SDG&E identifies the following:

> 3. Aggregator readiness and operational complexity, particularly the complexity of coordinating and dispatching specific subsets of DERs when resources are aggregated.
> 4. Telemetry, settlement, and [measurement and verification (M&V)] costs relative to the value of the service provided.
> 5. Customer acquisition costs, customer interest, and compensation expectations – DER owners will require compensation sufficient to permit utility dispatch, and at compensation levels that provide overall ratepayer benefit. Opportunities have to date been limited.
> 6. Dependability for planning-grade commitments, discussed in response to Question 13.[8]

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[8] SDG&E Opening Comments, at 18.

SCE also describes barriers in response to the same question:

- Technical barriers include availability and interoperability of devices, reliability of the communications backbone, cybersecurity constraints, lack of measurement and verification, and challenges of integration with utility systems.
- Operational barriers take the form of uncertain availability due to customer override behavior, participation fatigue, and changing customer needs.
- Economic barriers include customer equipment costs, absent and/or insufficient incentives (whether compensation or alternative rate design), as well as split or conflicting incentives.[9]

SCE later discusses the potential "need to adopt an over-enrollment strategy" as part of an effort to "account for variability in customer participation and resource availability."[10]

While CalCCA acknowledges these technical and operational barriers identified by SDG&E and SCE, many of these barriers can be better addressed through marketplaces than via Grid-Edge DERMS programs. As described in CalCCA's Flexible Service Connections (FSC) Ruling Opening Comments in this proceeding:

> [F]lexibility marketplaces facilitate the acquisitions of and transactions between utilities and flexible service providers, matching system needs with resource capabilities and availability. The marketplace operator, in coordination with the IOUs, prequalifies bidders and resources, publishes utility flexibility competitions, ranks bids, presents utility contracts, runs settlements, and may relay dispatch instructions.[11]

Marketplaces also serve as a single interface between DER providers and IOUs for the provision of demand flexibility services, providing IOUs with "greater access to DER assets,"

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9 SCE Opening Comments, at 10.

10 *Ibid*.

11 *See CalCCA Comments on Assigned Commissioner's and Administrative Law Judge's Ruling Requesting Comment on Assigned Commissioner's Proposal on FSC* (CalCCA FSC Ruling Opening Comments), R.21-06-017 (July 27, 2026), at 5, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M612/K353/612353887.PDF.

and offering demand flexibility providers "access to multiple market offerings and value-stacking opportunities."[12] A well-designed marketplace lowers transactional barriers and encourages robust participation by demand flexibility providers, obviating the need to "over-enroll" DER assets as might be required under a program-, contract-, or tariff-based IOU offering. It also shifts customer acquisition and management costs and responsibilities to demand flexibility providers, reducing the burden on IOUs.

PG&E recognizes the potential benefits of a scalable platform to coordinate flexibility services from multiple providers and resources, stating:

> To fully realize the potential of behind-the-meter DERs, continued evolution of the technology ecosystem will be necessary, including the development of interoperability standards, coordination mechanisms, and aggregation capabilities that enable multiple resource types to operate in concert and provide grid services in a reliable and scalable manner. Such advancements will enhance the ability of DER portfolios to deliver greater system value and support a broader range of distribution grid needs.[13]

PG&E specifically lists "market-based approaches" among the participation models for a DER orchestration framework.[14]PG&E therefore sees value in pursuing a marketplace option as part of its DER orchestration strategy.

The IOUs' comments reinforce CalCCA's recommendation to incorporate a demand flexibility marketplace platform into the IOU-led DER orchestration framework. Indeed, the Utility Consumers' Action Network (UCAN) recommend a process for deploying statewide or IOU-specific market functions, including an implementation working group supported by a systems administrator consultant, resulting in a proposal for party comment.[15] The Commission

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[12] *Ibid*.
[13] PG&E Opening Comments, at 16.
[14] *Id*. at 19.
[15] UCAN Opening Comments, at 15-18.

could consider this approach in requiring the evaluation of a flexibility marketplace to support DER orchestration.

III. ANY IOU PILOTS SHOULD INCLUDE CCA-MANAGED DERS, BE TIME-LIMITED, AND SHOULD FOCUS ON DEMONSTRATING THE TECHNICAL AND OPERATIONAL CAPABILITIES OF IOU GRID-EDGE DERMS

If the Commission authorizes IOU pilots, it should avoid IOU overreliance on early-stage demonstrations and instead authorize only pilots that include CCA-managed DERs, are time-limited, and that focus on demonstrating IOU Grid-Edge DERMS technical and operational capabilities. While CalCCA does not oppose the use of pilot programs to inform the development of a DER orchestration framework, IOU Opening Comments included proposals for lengthy, IOU-centric, and potentially unnecessary demonstrations and pilot programs that could delay implementation of the framework. If the proposed pilots focus only on IOU-managed DERs, are designed around a single use case, or include costly communication or interoperability equipment, they will not accurately demonstrate demand flexibility capabilities that could be sourced via a marketplace platform.

SCE proposes a DER Orchestration Development Framework designed as a "pathway for the implementation of full-scale DER orchestration through structured, capability-building development activities."[16] SCE further describes the intent of its proposal:

> [t]he framework should help utilities generate empirical evidence on how DER orchestration can maximize customer value, support location and time-specific grid needs, operate reliably with customers and third parties, and identify the conditions necessary for future scaling.[17]

Similarly, SDG&E advocates for piloting programs to demonstrate targeted infrastructure deferral opportunities, but limiting compensation to "DERs that are in the right place, at the right

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16 SCE Opening Comments, at A1.

17 *Ibid*.

time, in the right quantity, and with the right performance characteristics to provide the needed distribution service."[18] It bases its recommendation on its experience with the now-defunct Distribution Infrastructure Deferral Program, which incorporated numerous design flaws, including a lengthy, uncertain application process that yielded small-scale, short-term deferral opportunities with limited commercial appeal.

Unless the IOUs' proposed demonstrations include a marketplace platform, they are unlikely to provide the empirical evidence SCE seeks. Small-scale, limited demonstrations with no long-term revenue certainty and potentially high-cost communications or interoperability requirements may not attract sufficient participation to yield meaningful insights. Likewise, limited participation in such demonstrations may lead to the incorrect conclusion that customer-owned DERs cannot support grid deferrals.

One of the keys to the success of a DER orchestration framework is the ability to access large numbers of diverse DERs located throughout the distribution grid that can reliably and consistently provide the necessary flexibility. Marketplace platforms working in concert with IOU DERMS offer the greatest opportunity to achieve this goal compared with standalone IOU Grid-Edge or Enterprise DERMS solutions.[19] A well-designed marketplace amplifies the impact of the IOU Grid-Edge DERMS, increasing the potential for infrastructure deferral or avoidance, resulting in ratepayer savings.[20] Markets also provide value-stacking opportunities for demand flexibility providers, encouraging participation and providing greater resource diversity.[21]

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18 SDG&E Opening Comments, at 24.

19 *See* CalCCA Opening Comments, at 6.

20 *Ibid*.

21 *See* CalCCA FSC Ruling Opening Comments, at 6 (proposing a flexibility marketplace to accelerate DER participation and create more opportunities for grid deferral or avoidance, resulting in greater ratepayer benefits).

Underscoring the importance of avoiding overreliance on pilots in its response to a question posed during the TSO–DSO Coordination WS, the independent marketplace operator Piclo stated that "there will be a lot of nervousness from a lot of players if DSOs and IOUs start launching pilots for flexibility."[22] Piclo advised focusing instead on creating a framework that "sets you up for something which is really going to scale," and cautioned against "spending too much time worrying about how orchestration systems will work in five years."[23] To overcome the IOUs' reticence about whether enough market flexibility will emerge, Piclo argued that only "real data on what is performing at scale" will suffice.[24]

The Commission should consider lessons learned from Piclo's experience in the United Kingdom's flexibility markets and limit pilots to short-duration demonstrations focused on addressing the technical and operational challenges of deploying IOU Grid-Edge DERMS in preparation for integration with a marketplace platform. Further, these pilots should include CCA and third-party-managed DERs to help prepare these entities for an eventual demand-flexibility marketplace. The Commission should also ensure that the pilot and demonstration activities do not delay necessary stakeholder discussions to develop the DER orchestration framework and demand flexibility marketplace.[25]

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22 *WS Recording, Transmission System Operator* (TSO) – *Distribution System Operator* (DSO) *Coordination WS*, R.21-06-017 (June 5, 2026), at 3:20:15, https://youtu.be/AHbDF0PsbZM.

23 *See id*., at 3:19:30.

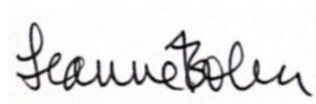
24 *See id*. at 3:21:31.

25 *See* CalCCA Opening Comments, at 6-9 (proposing a working group process to ensure fulsome discussion of the DER orchestration framework and marketplace).

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,



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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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