Regulatory Filings

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	R.19-03-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO PETITION FOR MODIFICATION OF DECISION 21-06-033 BY THE ALLIANCE FOR RETAIL ENERGY MARKETS, CALIFORNIA COALITION OF LARGE ENERGY USERS, DIRECT ACCESS CUSTOMER COALITION, REGENTS OF THE UNIVERSITY OF CALIFORNIA, SHELL ENERGY NORTH AMERICA (US), L.P. AND WESTERN POWER TRADING FORUM

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May 6, 2026

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SUMMARY OF RECOMMENDATIONS[1]

The Commission should reject the Petition and refrain from recommending Direct Access expansion at this time, because:

- The Commission has fulfilled its obligation required in section 365.1(f), which is now inoperative, and has no further role in making additional recommendations to the Legislature on the Direct Access cap;
- Even if the Commission were to reconsider the DA Decision as a result of this Petition or otherwise, it should continue to recommend against expanding Direct Access because
    - Clean energy sales and resource development related factors driving the Commission to recommend against expanding the Direct Access cap in the DA Decision have not materially changed; and
    - Claims that Direct Access service is "better-suited" for large load customers than other LSEs, including CCAs, have not been adequately supported.

[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 Implement Senate Bill 237 Related to Direct Access.	R.19-03-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO PETITION FOR MODIFICATION OF DECISION 21-06-033 BY THE ALLIANCE FOR RETAIL ENERGY MARKETS, CALIFORNIA COALITION OF LARGE ENERGY USERS, DIRECT ACCESS CUSTOMER COALITION, REGENTS OF THE UNIVERSITY OF CALIFORNIA, SHELL ENERGY NORTH AMERICA (US), L.P. AND WESTERN POWER TRADING FORUM

Pursuant to Rule 16.4(f) of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[2] the California Community Choice Association[3] (CalCCA) hereby submits this Response to the *Petition for Modification of Decision 21-06-033 by The Alliance for Retail Energy Markets, California Coalition of Large Energy Users, Direct Access Customer Coalition, Regents of The University of California, Shell Energy North America (US), L.P. and Western Power Trading Forum*[4] (the Petition), dated April 6, 2026. For the reasons set forth herein, the Petition should be denied.

[2] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021), https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

[3] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, 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, and Valley Clean Energy.

[4] *Petition for Modification of Decision 21-06-033 by The Alliance for Retail Energy Markets, California Coalition of Large Energy Users, Direct Access Customer Coalition, Regents of The University of*

I. INTRODUCTION

The Alliance for Retail Energy Markets(AReM), California Coalition of Large Energy Users (CLEU), Direct Access Customer Coalition (DACC), Regents of The University of California (UC), Shell Energy North America (US), L.P. (Shell), and the Western Power Trading Forum (WPTF) (collectively, Petitioners) request the Commission modify D.21-06-033[5] (DA Decision) which recommended to the Legislature against further expansion of the Direct Access program.[6] The DA Decision concluded that expansion would have risked the state's reliability goals and potentially result in increased greenhouse (GHG) gas emissions, criteria air pollutants, and toxic air contaminants when compared to maintaining the cap.[7]

In support of their request, Petitioners first contend that the Commission's concerns set forth in the DA Decision no longer exist, given those concerns have "long since been addressed by both the Legislature and the Commission."[8] Petitioners cite the comprehensive framework of Resource Adequacy (RA), Renewables Portfolio Standard (RPS), and IRP under which ESPs are

California, Shell Energy North America (US), L.P. and Western Power Trading Forum, R.19-03-009 (Apr. 6, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M604/K025/604025685.PDF.

[5] Decision (D.) 21-06-033, *Decision Recommending Against Further Direct Access Expansion*, Rulemaking (R.) 19-03-009 (June 24, 2021), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K215/390215673.PDF.

[6] Petitioners also filed an application for rehearing (AFR) of the 2026 Integrated Resource Planning (IRP) decision, D.26-02-057. Petitioners argue that the IRP Decision will cause inappropriate cost shifting to Direct Access customers given the IRP Decision orders procurement by all investor-owned utilities (IOU), community choice aggregators (CCAs), and electric service providers (ESP) for system reliability needs, despite ESPs not being allowed to serve the new load driving the need for incremental procurement due to the Direct Access cap. CalCCA filed a Response to the AFR on April 21, 2026, arguing that: (1) the IRP Decision does not constitute legal error given the Commission assigned procurement obligations to ESPs based on system reliability need; (2) the request that the ESP share be reallocated to other load-serving entities (LSEs) should be rejected and instead addressed in the IRP procurement track or in the Reliable and Clean Power Procurement Program given the impacts on all parties; and (3) the request for reconsideration of Direct Access expansion in the AFR should be rejected given it is outside the scope of the IRP Decision.

[7] DA Decision, at 2.

[8] Petition, at 21.

now required to make contributions to system reliability and the State's clean energy goals.[9] Petitioners also argue that Direct Access is "ideal" and "better suited" than CCAs or IOUs for serving new large commercial loads, such as data centers.[10]

The Petitioners' requested modification should be rejected, and no recommendation should be made to the Legislature to reopen Direct Access. As an initial matter, it is the Legislature, not the Commission, that has the authority to modify the Direct Access cap, and the Commission has no current role in providing a recommendation to the Legislature on this topic. Public Utilities Code section 365.1(a) allows the Legislature, by statute, to lift the suspension or otherwise authorize Direct Access.[11] The DA Decision was decided pursuant to former section 365.1(f), which has since become inoperative. Section 365.1(f) required the Commission to provide recommendations and findings to the Legislature regarding potential Direct Access reopening *on or before June 1, 2020.* In making its recommendation in the DA Decision, the Commission fulfilled its obligation required in section 365.1(f) and has no further obligation to make additional recommendations to the Legislature on this matter.

Even if the Commission were to reconsider the DA Decision as a result of this Petition or otherwise provide recommendations on Direct Access to the Legislature, however, the Commission should still find that lifting the Direct Access cap is not the right policy decision for California at this time. Indeed, the factors driving the Commission to recommend against expanding the Direct Access cap in the DA Decision have *not* materially changed. For example, although all LSEs are subject to the same RPS and IRP compliance requirements, ESPs' share of retail sales from clean resources and progress on new resource development continues to lag

[9] Petition, at 9, 21.
[10] Petition, at 11.
[11] All subsequent code sections cited herein are references to the California Public Utilities Code specified.

behind other LSEs, suggesting these factors are still relevant. In addition, the Petitioners fail to justify their claims that ESPs are *better-suited* than other LSEs, including CCAs, to serve new large commercial loads, such as data centers. Even if an argument could be made to open Direct Access for data center load, the Petitioners' recommendation is overly broad, extending to "all non-residential customers."[12]

In summary, the Commission should reject the Petition and refrain from recommending Direct Access expansion to the Legislature at this time, because:

- The Commission has fulfilled its obligation required in former section 365.1(f), which is now inoperative, and has no further role in making additional recommendations to the Legislature on the Direct Access cap;
- Even if the Commission were to reconsider the DA Decision as a result of this Petition or otherwise make any recommendations on reopening Direct Access, it should continue to recommend against expanding Direct Access because
    - Clean energy sales and resource development related factors driving the Commission to recommend against expanding the Direct Access cap in the DA Decision have not materially changed; and
    - Claims that Direct Access service is "better-suited" for large load customers than other LSEs, including CCAs, have not been adequately supported.

II. THE COMMISSION HAS FULFILLED ITS OBLIGATION REQUIRED IN SECTION 365.1(F) AND HAS NO FURTHER ROLE IN MAKING ADDITIONAL DIRECT ACCESS EXPANSION RECOMMENDATIONS TO THE LEGISLATURE

The Petition should be rejected because it is the Legislature, not the Commission, that has the authority to modify the Direct Access cap, and the Commission has no current role in providing the Legislature with recommendations on this topic. The DA Decision was decided pursuant to former section 365.1(f), which has since become inoperative. Section 365.1(f) required the Commission to provide recommendations and findings to the Legislature regarding

[12] *See* Petition, at 5, and Exhibit A.

potential Direct Access reopening on or before June 1, 2020. The recommendations were to address "implementing a further direct transactions reopening schedule, . . . for all remaining nonresidential customer accounts in each electrical corporation's service territory."[13] The findings, to be considered when developing the recommendations, were that the recommendations: (1) are consistent with the state's GHG emission reduction goals; (2) do not increase criteria air pollutants and toxic air contaminants; (3) ensure electric system reliability; and (4) do not cause undue shifting of costs to bundled service customers of an electrical corporation or to direct transaction customers.[14]

The Commission concluded in the DA Decision that it could not recommend reopening Direct Access because it could not make findings (1) through (3) (and therefore did not need to address finding (4)).[15] While the section 365.1(f) requirements are no longer operative, current section 365.1(a) does allow the Legislature, by statute, to lift the suspension or otherwise authorize Direct Access. In making its recommendation in the DA Decision, the Commission fulfilled its obligation required in section 365.1(f) and has no further role in making additional recommendations to the Legislature on this matter.

III. EVEN IF THE DA DECISION IS RECONSIDERED OR DIRECT ACCESS RECOMMENDATIONS ARE MADE, THE COMMISSION SHOULD CONTINUE TO RECOMMEND AGAINST DIRECT ACCESS EXPANSION BECAUSE ESP CLEAN ENERGY SALES AND RESOURCE DEVELOPMENT HAVE NOT MATERIALLY CHANGED

Petitioners argue that factors cited by the DA Decision to recommend not lifting the Direct Access cap are no longer present, especially given ESPs are now subject to the same RPS, IRP, and RA requirements as all other LSEs. As set forth below, however, certain factors have

13 Pub. Util. Code § 365.1(f)(1).
14 *Id.* § 365.1(f)(2).
15 DA Decision, at 18-22.

not materially changed, including that: (1) historical progress demonstrates that ESPs lag behind other LSEs in the amount of retail sales from clean resources, and the significant procurement necessary to meet future compliance requirements indicates that this trend may continue; and (2) a review of the Commission's 2026 RPS Report and LSE IRP Plans suggest ESPs continue to lag behind on new resource development, and catching up may already be infeasible given current market conditions and interconnection constraints. As a result, Petitioners' request to reopen Direct Access should be rejected.

A. ESPs' Share of Retail Sales from Clean Resources Has Historically Been Below the Share Achieved by the CCAs and IOUs

The DA Decision recommends against further expansion of the Direct Access program in part because "[i]f past procurement indicates future outcomes, then load migration from IOUs or CCAs to ESPs may lead to a net decline in RPS procurement, relative to maintaining the current cap on Direct Access, which may increase GHG emissions and increase criteria air pollutants and toxic air contaminants."[16] The Petitioners state that concerns regarding RPS procurement and criteria air pollutants are unfounded because ESPs, like all LSEs, are subject to the same RPS and criteria air pollutant standards and ESPs recently met their requirements for the 2021-2024 RPS compliance period.[17] Although all LSEs are subject to the same requirements, ESPs' share of retail sales from clean resources has historically been below the share achieved by the IOUs and CCAs, as demonstrated in Figure 1, below.

[16] DA Decision, at 11.
[17] *See* Petition, at 17-18.

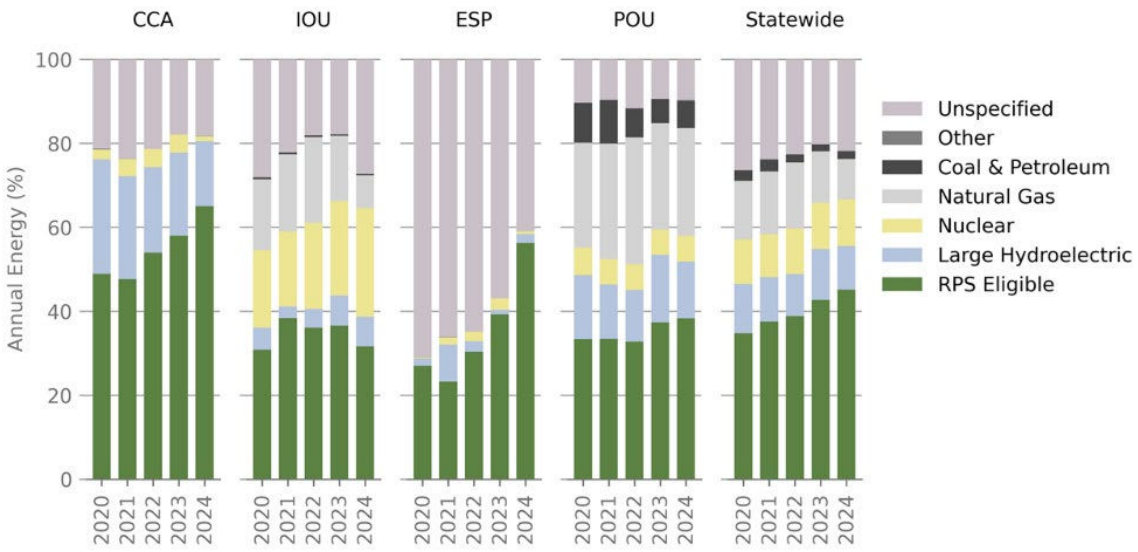


Figure 1: Sources of Annual Energy Sales by LSE Type[18]

ESPs have historically been minimally compliant with RPS requirements, and going forward, the 2025 RPS Report suggests the 2025-2027 and 2028-2030 compliance periods may be a challenge for ESPs, as demonstrated by Figure 2, below.

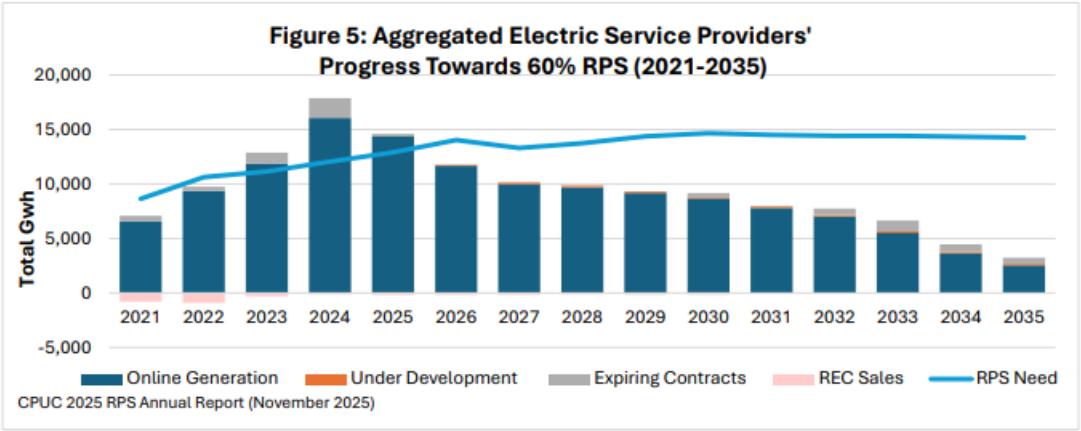


Figure 2: Aggregate ESP Progress towards 60 Percent RPS (Source: CPUC 2025 RPS Report)

The Commission's 2025 RPS Report finds that, "[t]he ESPs' forecasted procurement percentages are lower in the future because a substantial amount of the ESPs' RPS procurement

[18] CalCCA analysis of the Power Source Disclosure Annual Reports submitted to the CEC for 2020-2024, https://www.energy.ca.gov/programs-and-topics/programs/power-source-disclosure-program.

is in short-term contracts…" and "many will need significant procurement to meet the RPS 2025-2027 compliance period and beyond."[19]

Historical progress demonstrates that ESPs lag behind other LSEs in the amount of retail sales from clean resources. The significant amount of procurement necessary to meet future compliance requirements indicates that this trend may continue. The Commission's concern expressed in the DA Decision that "…load migration from IOUs or CCAs to ESPs may lead to a net decline in RPS procurement, relative to maintaining the current cap on Direct Access, which may increase GHG emissions and increase criteria air pollutants and toxic air contaminants," is therefore still relevant.

B. The RPS Report and LSE IRP Plans Suggest ESPs Continue to Lag Behind on New Resource Development, and Catching Up May Already Be Infeasible

The DA Decision also recommends against further expansion of the Direct Access program because of "ESPs' lack of track record in building new generation resources," which the Commission found may increase reliability risks.[20] As demonstrated in Figure 2 above, thus far, ESPs have very little generation under development to meet RPS requirements. This is in contrast to CCAs, who plan to meet RPS requirements with significant amounts of generation under development, as demonstrated in Figure 3, below.

[19] *See 2025 California Renewables Portfolio Standard Annual Report* (Nov. 2025), at 24, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2025/2025-california-renewables-portfolio-standard-rps-annual-report.pdf.

[20] DA Decision, at 11.

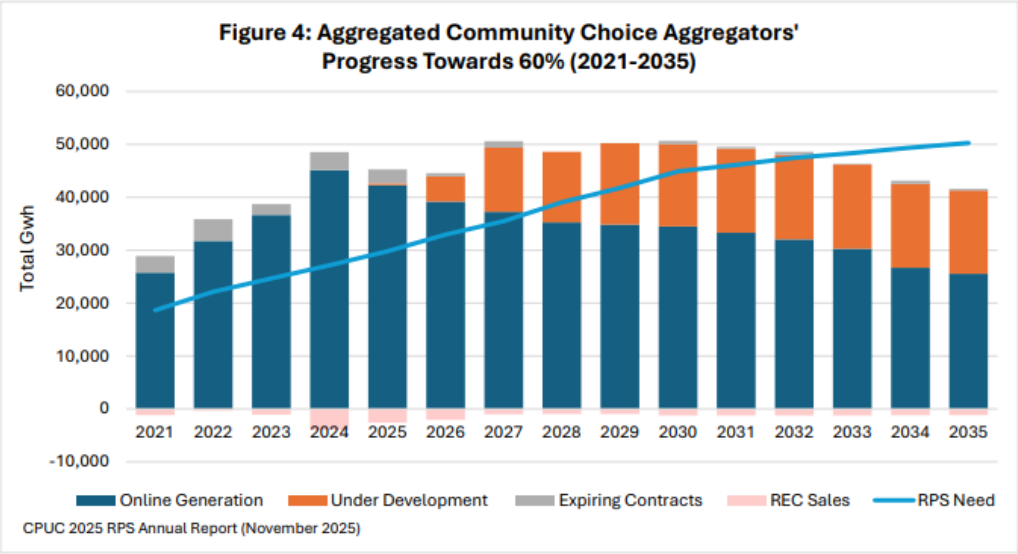


Figure 3: Aggregate CCA Progress Towards 60 Percent RPS (Source: CPUC 2025 RPS Report)

IRP plans similarly demonstrate that ESPs are lagging behind other LSEs, as a percentage of peak demand, in the development of new clean resources, as demonstrated in Figure 4, below. LSEs most recently filed IRP plans in 2022.

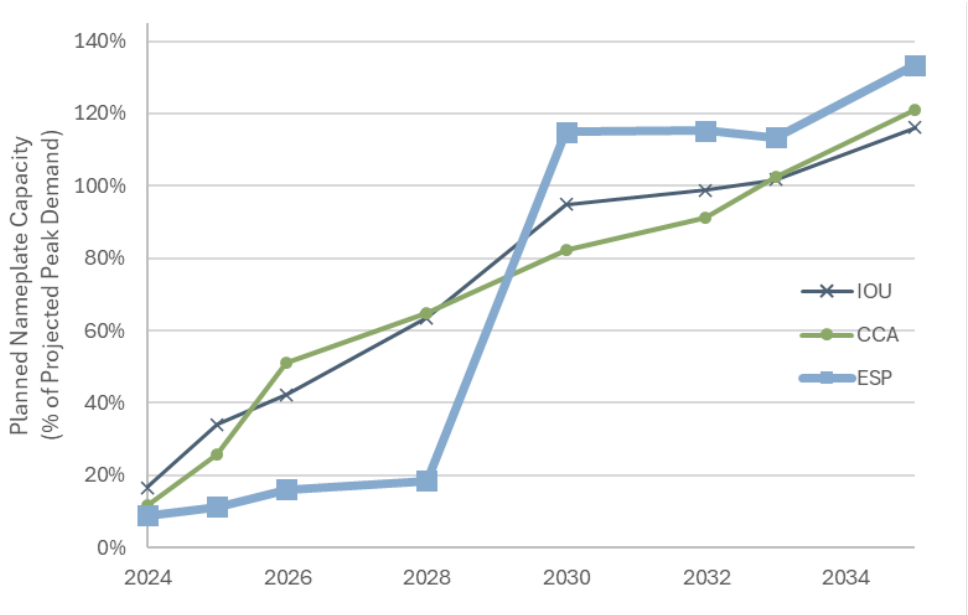


Figure 4: New Resource Additions using Aggregated 25 MMT Plans from 2022 LSE IRPs[21]

[21] CalCCA analysis of new resource additions for the aggregated 25 MMT plans in the 2022 IRPS on Slide 17-19, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-

In those plans, ESPs show very little planned new resource additions, as a percentage of projected peak demand, from 2024-2028. Additionally, ESPs forecasted increase in new resource additions between 2028 and 2030 – going from 20 percent to over 110 percent – will likely be a significant challenge under current market conditions and interconnection timelines.

The ability for the state to meet climate and reliability objectives requires expeditious development of new resources. Figures 2 through 4 demonstrate that it may not be possible to achieve the same pace of new resource development if Direct Access is expanded relative to maintaining the current cap. For these reasons, the Commission's concern around the "ESPs' lack of track record in building new generation resources," continues to be relevant.

IV. THE PETITIONERS FAIL TO DEMONSTRATE WHY ESPS ARE "BETTER-SUITED" THAN OTHER LSES FOR SERVING LARGE LOAD CUSTOMERS GIVEN IOUS AND CCAS ARE CURRENTLY SERVING LARGE LOAD CUSTOMERS

The Petitioners' argument that ESPs are somehow in a better position to serve large customers than other LSEs, including CCAs, is unfounded and unsubstantiated. Petitioners state that "ESPs are *better suited* at preventing cost shifting to existing customers than CCAs and IOUs to meet the needs of new large customers because ESPs will place such customers under dedicated contract."[22] Petitioners further state that "[n]ew large loads get the advantage of

division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/2022_lse_plan_aggregation_steps_20231004.pdf. To obtain a percentage of projected peak demand, CalCCA used the peak load share from 2021 that was used to define MTR requirements (Slide 12 of https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/compliance-status-reportmid-term-reliability-mtr-and-supplemental-mtr.pdf), then assumed that the ratio of peak demand to retail sales in 2021 remains constant out through 2035. CalCCA then used the Individual "LSE Energy Load Forecast Assignments for Use in 2022 LSE IRPs", which shows the projected retail sales out through 2035, (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2022-final-ghg-emission-benchmarks-for-lses_public.xlsx) to calculate the projected peak demand for each LSE category.

[22] Petition, at 16.

flexibility in contracting that can meet their needs including providing the customer's desired level of green power attributes, while other customers bear no risk of generation rate increases or stranded costs."[23]

This "win-win situation for large load customers and the rest of the state,"[24] however, is not unique to Direct Access service. CCAs can already structure individual transactions with new large loads in the same way ESPs can today, tailoring the agreement to the situation. CCAs can structure any such transactions so that the CCA can remain consistent with the clean energy and environmental objectives of their communities. The Commission is now considering the IOUs' approach to these issues in the Advanced Rate Design proceeding (R.26-04-009), and nothing prevents the Commission from enabling customer-specific contracts for this purpose. CCAs and IOUs alike can "ring fence" transactions using long-term obligations and security requirements, designed for each scenario, to prevent shifting costs to other customers in the future.

For example, Silicon Valley Clean Energy (SVCE) entered into a special agreement with Google in 2022 to provide 24/7 carbon-free energy service for Google's offices in Mountain View and Sunnyvale, California. SVCE agreed to match carbon-free electricity with Google's local demand for at least 92 percent of all hours in the year – from a tailored portfolio of renewable energy resources meeting additionality requirements. Google also agreed to flex its building electric loads to further improve carbon-free energy and cost performance, and to invest in electrification at its local facilities.[25]

[23] Petition, at 11-12.
[24] *Ibid.*
[25] *See* "Silicon Valley Clean Energy and Google Announce Comprehensive 24/7 Carbon-Free Energy Agreement" (June 15, 2022), https://svcleanenergy.org/news/silicon-valley-clean-energy-and-google-announce-comprehensive-24-7-carbon-free-energy-agreement/.

San José Clean Energy (SJCE) provides another example of how CCAs can provide benefits to large loads. The City of San José, of which SJCE is a part, has its own Large-Load Energy Customer Development department to "support the next generation of data centers" by providing a "concierge-style support" to help data centers developers and operators navigate energy interconnections, zoning, and permitting.[26] In addition, the City of San José and PG&E have partnered to streamline the interconnection process for large-load energy users such as data centers. SJCE is connected to the process through its transparent pricing for data centers, clean energy options, and energy efficiency programs and initiatives that can help data centers reduce peak demand and improve operational resilience. In short, Petitioner arguments that Direct Access service is somehow "better suited" to serve large loads, including data centers, is misguided and can be easily debunked.

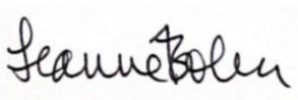
Even if an argument could be made to open Direct Access for data center load, the Petitioners' recommendation is also unjustifiably broad. While the Petitioners claim that Direct Access is "ideal" for data centers, the Petitioners propose to expand Direct Access eligibility to "all non-residential customers." The Petition offers no justification for this broad approach. For these reasons, the Petition does not demonstrate a need to lift the Direct Access cap for the purpose of serving large loads.

[26] *See* "Powering San Jose," https://www.sjeconomy.com/how-we-help/programs-and-services/powering-san-jos-energy-infrastructure-for-data-centers#sjce.

V. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests that the Commission deny the Petition for Modification.

Respectfully submitted,



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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on California Advanced Electric Rate Design.	R.26-04-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE ORDER INSTITUTING RULEMAKING ON CALIFORNIA ADVANCED ELECTRIC RATE DESIGN

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California Public Utilities Commission Rules of Practice and Procedure

Rule 6.2 1

SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends the Commission:

- Ensure that any tariff changes preserve customer choice and recognize the role of CCAs as the default generation providers for customers within their service territories;

- Adopt the proposed scope of the proceeding, with the addition of: (1) statewide information-sharing requirements between IOUs and CCAs regarding large load interconnection requests and new customer development; and (2) the consideration of rate designs to best leverage behind-the-meter storage as a grid asset;

- Establish clear coordination mechanisms between this proceeding and related proceedings, including the use of shared workshops, aligned procedural schedules, and iterative record development to reduce duplication and improve consistency across proceedings;

- Structure the proceeding into separate tracks and phases to better manage complexity and statutory deadlines, including: (1) first determining whether data centers warrant distinct tariff treatment separate from other large loads before developing broader large load tariff structures; and (2) sequencing broader rate reform issues before revisiting the Base Services Charge (BSC) to ensure that fixed-charge discussions are informed by overall rate structure decisions; and

- Authorize the use of an outside consultant to support rate design analysis in this proceeding.

[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 on California Advanced Electric Rate Design.	R.26-04-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE ORDER INSTITUTING RULEMAKING ON CALIFORNIA ADVANCED ELECTRIC RATE DESIGN

The California Community Choice Association[2] (CalCCA) submits these comments pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[3] in response to the *Order Instituting Rulemaking on California Advanced Electric Rate Design*[4] (OIR), issued April 10, 2026, and the directives therein.

I. INTRODUCTION

This proceeding reflects a broad and ambitious effort by the Commission to revisit foundational elements of electric rate design across customer classes, policy objectives, and statutory directives. As the Commission explains, this proceeding is tasked with updating both

[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, Peninsula Clean Energy, 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, and Valley Clean Energy.

[3] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021), https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

[4] *Order Instituting Rulemaking on California Advanced Electric Rate Design*, Rulemaking (R.) 26-04-009 (Apr. 10, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M604/K677/604677976.PDF.

residential and non-residential rate design, revisiting marginal cost inputs, addressing affordability concerns, and incorporating new and evolving policy priorities—including demand flexibility, electrification, and the treatment of large new loads such as data centers.[5] At the same time, the OIR will tackle issues deferred from R.22-07-005, while also implementing new legislative mandates from Senate Bill (SB) 57[6] and Assembly Bill (AB) 2109.[7] The resulting scope spans a wide array of interdependent issues, from time-of-use rate design and fixed charge structures to cost allocation, equity considerations, and emerging load impacts, all of which are deeply interconnected and will require careful coordination to avoid unintended consequences.

Notwithstanding this breadth, the Commission has established an aggressive procedural timeline, with an expectation that the proceeding will be completed within 24 months and with key policy proposals and decisions advancing on a much shorter cadence.[8] This compressed schedule underscores the urgency of the Commission's objectives, particularly with respect to affordability and system efficiency, but also presents practical challenges given the complexity of the issues presented and their overlapping nature. Many of the questions identified in the preliminary scope are interrelated, such that changes in one area will necessarily drive changes in others.[9] Accordingly, while the goals of this proceeding are appropriately ambitious, the Commission should remain attentive to the need for sequencing, prioritization, and iterative

[5] OIR, at 1–2.

[6] Senate Bill 57 (Padilla, Ch. 647, Stats. 2025). SB 57 requires the Commission to provide an assessment by January 1, 2027, on the potential cost impacts from new, large transmission-connected loads from data centers on electrical corporations and their customers, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202520260SB57.

[7] Assembly Bill 2109 (Carrillo, Ch. 700, Stats. 2024). AB 2109 requires the Commission to implement an exemption from non-bypassable or departing load charges for certain industrial customers that utilize process heat recovery technology, subject to a cap and prescribed requirements to be established by the Commission, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240AB2109.

[8] *Id.*, at 14.

[9] *Id.*, at 11–13.

development of the record to ensure that the resulting rate design framework is both well-founded and durable.

Further, though the proceeding will focus in part on evaluating rate design for current customers, it will also encompass the broader framework for providing electric service to new customers. While the investor-owned utilities (IOU) are the sole delivery service providers in their service territories, community choice aggregators (CCA) within those service territories are the default generation service providers for new load located within the CCA territories, subject to a customer's ability to opt out of CCA service. Accordingly, any tariff changes considered by the Commission should preserve and reflect customer choice.

Further, consistent with this default role for serving new customers, CCAs require timely access to information regarding new large loads and anticipated generation needs to enable procurement of sufficient resources on behalf of those customers. As the Commission considers information sharing requirements and data sharing provisions, it should ensure, consistent with statutory requirements and Commission precedent, that CCAs maintain access to customer and load data necessary to fulfill their procurement and service obligations.[10]

Given these considerations, CalCCA recommends the Commission adopt the scope proposed in the OIR, with the following additions:

- Ensure that any tariff changes preserve customer choice and recognize the role of CCAs as the default generation providers for customers within their service territories;

[10] Cal. Pub. Util. Code § 366.2(c)(9) requires IOUs to "cooperate fully with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs." In D.04-12-046, the Commission interpreted this section to provide the CCAs with "all relevant usage information, load data and customer information." D.04-12-046, *Order Resolving Phase 1 Issues on Pricing and Costs Attributable to Community Choice Aggregators and Related Matters*, R.03-10-003 (Dec. 16, 2004), at 52, https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/42389.PDF.

- Adopt the proposed scope of the proceeding, with the addition of: (1) statewide information-sharing requirements between IOUs and CCAs regarding large load interconnection requests and new customer development; and (2) the consideration of rate designs to best leverage behind-the-meter storage as a grid asset;
- Establish clear coordination mechanisms between this proceeding and related proceedings, including the use of shared workshops, aligned procedural schedules, and iterative record development to reduce duplication and improve consistency across proceedings;
- Structure the proceeding into separate tracks and phases to better manage complexity and statutory deadlines, including: (1) first determining whether data centers warrant distinct tariff treatment separate from other large loads before developing broader large load tariff structures; and (2) sequencing broader rate reform issues before revisiting the Base Services Charge (BSC) to ensure that fixed-charge discussions are informed by overall rate structure decisions; and
- Authorize the use of an outside consultant to support rate design analysis in this proceeding.

Each of these recommendations is discussed below in CalCCA's responses to the questions set forth in the OIR.

II. QUESTION 1: Please provide comments on the list of preliminary issues. Are there any missing issues?

CalCCA generally supports the scope of this proceeding as set forth in the OIR and agrees that a comprehensive examination of electric rate design is both timely and necessary given the scale of ongoing affordability pressures and the consideration of load growth (including from large loads and data centers) and the potential for resulting cost shifts to customers.[11] The breadth of issues identified, including updates to time-of-use rate design, evaluation of marginal cost methodologies, consideration of changes to the BSC, wildfire costs, and rate design for data center customers, reflects the complexity of aligning rates with cost-causation principles while advancing state policy objectives.[12]

[11] OIR, at 10–11.
[12] OIR, at 11–13.

CalCCA proposes an addition to Issue J in the Preliminary Scoping Memo (OIR Section 3), which addresses whether new tariffs are required for data centers and/or other large load customers and if yes, what should be included in those tariffs. In the ongoing Pacific Gas and Electric Company (PG&E) Rule 30 proceeding (A.24-11-007)[13], a proposed Settlement includes agreement between CalCCA and PG&E for certain information sharing timelines to ensure that CCAs operating in PG&E's territory receive notice of new transmission-interconnected loads requesting interconnection at sites where the CCA is the default generation provider.[14] CalCCA recommends that the scope of this proceeding clearly include the adoption of similar information sharing provisions in the other large IOU territories regardless of whether the CPUC determines that new tariffs for data centers and/or other large loads are needed. Extending these information sharing provisions across the state improves consistency and promotes the ability of CCAs to serve all of their customers affordably and efficiently.

CalCCA also proposes the Commission adopt an additional issue to the scope to consider rate designs that incentivize the utilization of behind-the-meter (BTM) storage resources to support state goals. Specifically, the Commission should consider rate designs that leverage the technical ability of storage to provide maximum value to the grid, rather than limiting BTM storage to serving on-site load. In this enhanced role, grid charging and grid exports could be driven by market needs and distribution constraints. Current export limitations to standalone BTM storage and grid charging restrictions to storage paired with solar are an unneccessary

[13] *Pacific Gas and Electric Company Application for Approval of Electric Rule 30 for Transmission Level Service for Retail Electric Service Rebuttal Testimony,* A.24-11-007 (Nov. 21, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M547/K155/547155949.PDF.

[14] *See Joint Motion for Adoption of Partial Settlement Agreement of Pacific Gas and Electric Company (U 39 E), the Public Advocates Office, the California Community Choice Association, and Sierra Club*, A.24-11-007 (May 7, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M606/K273/606273116.PDF.

regulatory constraint that limit the system value of BTM storage assets. CalCCA members are very interested in growing programs that support adoption and utilization of BTM storage but cannot accomplish this objective under the status quo. There is urgency to act: the storage investment tax credit will phase-out after 2032, and a larger and more flexible BTM fleet will increase distribution system utilization and provide opportunities to minimize needed grid upgrades necessitated by electrification.

With these additions, CalCCA recommends that the Commission adopt the proposed scope. At the same time, CalCCA highlights several additional issues within that scope that illustrate the breadth and complexity of the proceeding and the range of potential policy pathways available to the Commission. CalCCA recommends that the Commission include the following within its analysis of the following scoping items:

- **In response to Issue (e) (potential adjustments to the BSC):**
  - Adjustments to the BSC should be evaluated in conjunction with corresponding reductions to volumetric rates to improve marginal price signals, support beneficial residential electrification, and avoid unintended bill impacts; and
  - Consideration of fixed cost recovery and demand charge structures should prioritize designs that incentivize load shifting and efficient grid utilization, rather than merely reallocating cost recovery in a manner that weakens marginal price signals.
- **In response to Issue (j) (tariffs for data center/large load customers to prevent stranded costs and/or cost shifting):**
  - Large load planning and cost allocation should be aligned with Resource Adequacy (RA) and Integrated Resource Planning (IRP) frameworks to ensure that costs and risks are appropriately assigned; and
  - The Commission should evaluate tariff provisions that protect against speculative load, which could enable more accurate incorporation of such loads into RA planning.
- **In response to Issue (m) (rate design requirements for dynamic rates):**

- Improvements to customer data access is critical to enable CCAs to design and implement dynamic rates and related programs; and[15]
- To meaningfully evaluate rate design proposals in this proceeding.

The above list is not meant to be exhaustive but rather reflects a subset of topics that demonstrate the range of potential pathways this proceeding could take and the importance of developing a flexible, well-informed record. These examples also underscore the importance of data access, which is critical to enabling meaningful participation in dynamic rate design. Also absent sufficient access to the data necessary to evaluate proposals, parties will be unable to meaningfully assess rate design options or support the Commission in achieving the objectives identified in the OIR.

Further, as the list demonstrates, the success of this proceeding will depend in large part on how it is coordinated with a number of parallel Commission proceedings and related regulatory efforts. Several of the issues identified in the OIR, such as cost allocation, wildfire costs, demand flexibility, and rate structures for large and dynamic loads, are also being actively examined in other forums, including proceedings addressing the Power Charge Indifference Adjustment (PCIA), Demand Response, various ongoing dynamic rate pilots, and General Rate Cases (GRC), to name a few.[16] In addition, the Distributed Energy Resource (DER) proceeding (R.22-11-013) is examining data access issues that will likely overlap with the scope of this proceeding. Absent careful coordination, there is a risk that determinations made in this proceeding could either preempt or conflict with findings in those related dockets, leading to inefficiencies or inconsistent policy outcomes.

[15] *See, e.g., San Diego Community Power and Clean Energy Alliance Prehearing Conference Statement*, A.26-02-001 (Mar. 23, 2026), at 5-10, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K998/602998552.PDF.

[16] *See* PCIA (R.25-02-005), Enhanced Demand Response (R.25-09-004), Real Time Pricing Pilots (R.22-07-005), PG&E GRC Phase 2 (A.24-09-014), San Diego Gas & Electric Demand Flexibility Rates (A.26-02-001).

In addition, this proceeding will necessarily intersect with ongoing efforts outside the Commission, including work at the California Energy Commission regarding the Load Management Standards (LMS), which impact customer-facing rate designs and demand flexibility strategies. The OIR itself recognizes the importance of aligning rate design with load management objectives and dynamic pricing frameworks.[17] CalCCA therefore recommends that the Commission establish clear coordination mechanisms, such as shared workshops, aligned timelines, or iterative record development, to ensure that insights from dynamic rate pilots, LMS implementation, and related proceedings are effectively incorporated into this rulemaking. Doing so will help avoid duplicative efforts and support the development of a rate design framework that is both effective and responsive to evolving grid and customer needs.

III. QUESTION 2: Please provide comments on the schedule. Should this proceeding initially focus on only a portion of the preliminary issues? If so, which issues should be addressed first and why?

CalCCA recommends that the Commission establish separate tracks and phased implementation in this proceeding. While the issues before the Commission are connected by the overarching goals of improving affordability and advancing electrification, certain matters warrant more immediate attention due to statutory deadlines and pressing policy considerations. CalCCA recommends that Track 1 focus on large load and data center issues, while Track 2 address the broader set of rate reform questions. Within Track 1, a Phase 1 should prioritize the deadlines established by SB 57 and the threshold question of how best to prevent cost shifts and stranded costs associated with data centers. The broader issues of commercial and industrial rate signals and the legislative directives established by AB 2109, while important, are not subject to the same statutory timeline and would be better suited for more deliberate consideration in a Phase 2.

[17] OIR, at 2-4.

Track 2, which could proceed in parallel with Track 1, can provide a forum for the broader rate reform topics identified in the OIR. Although affordability remains an urgent concern, the scope, complexity, and interdependency of these issues warrant a more measured schedule. Accordingly, Phase 1 of Track 2 should prioritize broader rate design considerations, with a potential reevaluation of the BSC in Phase 2. Because the BSC has only been implemented for several months (and was only implemented by PG&E in March of this year), allowing time for additional data collection, while also addressing complex issues such as marginal cost methodologies, will support a more iterative, informed, and efficient process.

With these considerations in mind, CalCCA proposes the following scoping issues be addressed in the Tracks and Phases discussed below. The table below is also provided for ease of reference and to summarize CalCCA's procedural proposal.

Track	**Phase**	**Primary focus/Issues**	**Potential Timing**
Track 1 – Large Loads / Data Centers	Phase 1	Immediate issues related to SB 57 and data centers. (Issue j.)	Near-term
	Phase 2	Issues related to improving rate signals for large load customers and implementing the requirements of AB 2109. (Issues k. and l.)	Longer-term
Track 2 – Rate Reform	Phase 1	TOU, Dynamic Rates, Cost of Service, Wildfire, Equity, Marginal Cost, Demand Charges (Issues a. through d., g., i., and m.), BTM Storage.	Can run parallel with Track 1, but needs time for proper evaluation
	Phase 2	BSC (Issues e. and h.)	After Track 2 Phase 1 is completed

Track 1, Phase 1 would focus on data centers, which has been identified as Issue j.[18] SB 57 requires the Commission to submit a report on the potential for data center loads to result in

[18] OIR, at 12.

cost shifts of stranded costs by January 1, 2027.[19] In light of this deadline, CalCCA recommends that Issue j., considering whether new tariffs for data centers are needed to prevent cost shifts and stranded costs, should be prioritized for completion in an initial Track of this proceeding.

SB 57 directs the Commission to study:

- Increased procurement costs to meet data center energy demand;
- Costs of interconnection infrastructure to serve new data centers including the cost of stranded assets were a new customer stop operations; and
- "Opportunities" to address cost shifts driven by data center load.[20]

The Commission's report to address the statutory directives regarding data centers will assist the Commission and parties in addressing the threshold question of whether separate tariffs for data center customers are needed and by extension whether other large load tariffs are needed. Given the statutory deadline, Issue j. should therefore be taken up in the first track of this proceeding.

To the extent the Commission determines that new tariffs are needed for data centers or other large load customers, the Commission must acknowledge the unique regulatory and retail choice landscape in California. The tariffs should reflect the default role of CCAs serving new loads locating in their territory subject to each customer's ability to opt out of CCA service. CalCCA and PG&E have addressed in A.24-11-007 the tariff language required for PG&E's Rule 30 tariff to reflect the role of the CCA. Similar language should appear in any new tariff adopted by the Commission for data center and/or other large load customers.

Track 1, Phase 2 would focus on the remaining large load issues identified in Issue k. and l.[21] The issues related to improving rate signals for large load customers and implementing the requirements of AB 2109 are important and warrant careful consideration by the Commission.

19 OIR, at 8.
20 Cal. Pub. Util. Code § 913.22 (a).
21 OIR, at 12-13.

However, unlike the threshold questions related to data centers and the statutory deadlines established by SB 57, these issues are not subject to the same immediate Legislative mandates and would benefit from additional stakeholder development and analysis. Questions regarding how to design rate signals to support electrification, beneficial load growth, and load flexibility for large commercial and industrial customers involve complex policy tradeoffs with potentially broad implications for rate design and cost allocation. Similarly, implementation of AB 2109 will require the Commission to establish detailed eligibility criteria, caps, and operational requirements for customers utilizing process heat recovery technology. These topics are therefore better suited for Phase 2 of Track 1, where parties can build upon the record developed in Phase 1. In particular, the Commission's conclusions regarding the treatment of data centers, cost responsibility, and protections against stranded costs in Phase 1 may help inform and guide the Phase 2 discussion regarding appropriate rate structures for specific customer classes and technologies.

Track 2 would focus on the broader goals of rate reform. Phase 1 would concentrate on TOU, Dynamic Rates, Cost of Service, Wildfire, Equity, Marginal Cost, Demand Charges, BTM Storage and Phase 2 on BSC, covering Issues a. through i. and m..[22] CalCCA appreciates the Commission's effort to quickly address rate-related topics with significant impacts on customers. However, the complexity of topics such as TOU, dynamic rates, cost-of-service analyses, wildfire costs, demand charges, and equity will likely require more time for discussion than the contemplated timeline allows. CalCCA proposes including its additional request to evaluate BTM storage rate design in Phase 1 of Track 2. Transformative changes to rates require careful consideration and robust analysis to mitigate unintended consequences and achieve desired goals. The Commission is balancing the inherent tensions between the current, volumetric rate paradigm,

[22] OIR, at 11-13.

which historically incentivized energy efficiency investments and conservation, and the need to incentivize electrification with lower volumetric rates. Additionally, the PG&E and SCE dynamic pricing pilots are ongoing, with mid-term evaluations coming in Quarter 3 of 2026. Results from these pilots will provide valuable insights for consideration in any future rate structure changes.

The Commission should also carefully prioritize issues and consider how some proposed issues could inform others. Specifically, consideration of rate structures and potential proposals for adjustments would be beneficial before any discussion of the BSC. As a fixed charge, the BSC itself is a specific element of the broader rate structure. If parties propose and agree to adjustments to the balance between fixed and volumetric charges, those discussions could inform any needed changes to the BSC. Otherwise, changes could be made to the BSC, which are then overridden by larger structural changes. This would result in an inefficient and potentially confusing process. Additionally, as of the date of this filing, no IOU has implemented the BSC for a full year, and PG&E has only just begun implementing the BSC in its service area. Before contemplating changes to the BSC, the Commission should allow more time for gathering data from the implementation.

Therefore, the Commission should address broader rate design considerations in Phase 1 of this proceeding and defer consideration of potential BSC modifications to a subsequent Phase 2. This sequencing will promote an efficient process, mitigate unintended consequences, and allow for the collection and evaluation of additional BSC implementation data.

IV. QUESTION 3: What changes or updates are needed to improve the income verification processes used for the Base Services Charge (formerly the income-graduated fixed charge), as adopted in D.24-05-028? Please refer to the Process Working Group Final Report, served to the R.22-07-005 Service List on January 15, 2026, and included as Attachment A to this OIR.

CalCCA has no recommendations at this time for modifying the income verification process associated with the BSC. However, the Commission should carefully weigh the potential

approaches for income verification outlined in the Process Working Group Final Report (Income Verification Report) against their potential benefits and implementation costs. Decision 24-05-028 satisfied the statutory objectives by establishing a 3-tier BSC structure that minimized administrative complexity and costs by leveraging existing CARE/FERA enrollment processes, as well as deed-restricted housing eligibility.[23] The Commission adopted this approach, in part, because of concerns regarding the complexity and potentially significant costs associated with implementing a new statewide income verification framework.

The Commission subsequently established the Process Working Group to explore potential improvements to the BSC income verification process.[24] However, despite the recommendations contained in the Income Verification Report, additional investigation into implementation costs remains necessary before the Commission considers adopting any new verification framework. Notably, the Income Verification Report does not include cost estimates from the IOUs,[25] which would ultimately be responsible for implementing and administering any revised income verification process. The absence of this information leaves a significant gap in the record and makes it difficult to fully evaluate the operational and ratepayer impacts of either the Near-Term or Long-term Proposal.

Additionally, the Commission should remain mindful that the BSC is not inherently a cost-saving measure; it is a redistribution of costs. Accordingly, pursuing income verification changes that require substantial new administrative investments could increase overall costs for all customers, in direct opposition to the affordability goals the BSC is intended to advance.

[23] D.24-05-008, *Decision Addressing Assembly Bill 205 Requirements for Electric Utilities,* Rulemaking (R.) 22-07-005 (May 9, 2024), at Ordering Paragraph (OP) 3, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M531/K318/531318301.PDF.

[24] *Id.*, Conclusion of Law 14.

[25] *Income Verification Process Working Group Final Report* (Jan. 15, 2026), at 5-6, Table ES-1, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M603/K849/603849545.pdf.

More time for implementation, together with additional analysis of costs and operational impacts associated with potential income verification proposals, is necessary to effectively evaluate whether further BSC modification is necessary.

V. QUESTION 4: Are there any statutory interpretation issues of the Public Utilities Code that were not resolved in R.22-07-005 and should be considered in this proceeding regarding the Base Services Charge, reform of residential rates to better reflect cost causation, or regarding the interplay between the California Alternate Rates for Energy (CARE) program and the Base Services Charge?

Please see the answer to question 3, above.

VI. QUESTION 5: AB 205 amended Pub. Util. Code Section 739.9(c) to eliminate the requirement that the Commission "require each electrical corporation to offer default rates to residential customers with at least two usage tiers." Is it consistent with Public Utilities Code for the Commission to consider adopting default time-of-use rates that do not include usage tiers?

CalCCA has no comment on this issue at this time.

VII. QUESTION 6: What rate designs and tariff service agreement terms have been adopted in other states or regions for data center customers? Have other states or regions created a separate customer class for data center customers? Should these rates be applicable in California? If so, how?

Across the country, states are taking a wide variety of approaches to data centers and other large loads. Any consideration of potential tariff terms for data centers must be informed by California's retail competition and the role of CCAs as the default providers of generation service for new customers in their territories subject to the customer's opportunity to opt out of CCA service. Because very few states operate under a comparable retail competition structure, any effort by the Commission to adopt or adapt another state's approach to data center customers should account for the distinct role of CCAs in providing generation service.

As an initial matter, PG&E's proposed Rule 30 tariff, under consideration in A.24-11-007, provides a model for how to reflect the unique role played by the CCA. PG&E proposes to

incorporate clear language in its tariff highlighting the role of the CCA as the default provider of generation service for new customers in their tariff:

> INFORMATION SHARING WITH CCAs. For any Facility at a location within the service area of a CCA, the CCA is the default provider of generation service. The affected CCA will automatically serve any new Applicant in its service area subject to the choice of the Applicant to opt out of CCA service to receive generation service from PG&E. Upon receipt of an application for Retail Service for a Facility in a CCA's service area, PG&E will provide the affected CCA a copy of the application within twenty (20) business days of receipt, to ensure the CCA receives key information about the Retail Service request to inform the CCA of the new customer, including the customer contact information, location, facility type, capacity ramp schedule, on-site generation, and requested timing for the interconnection. PG&E will also provide to the affected CCA quarterly reports that provide updates on the proposed interconnection timelines related to Applicant, and any changes to customer information or timelines. Information provided by PG&E to the CCA is subject to confidentiality protections established by the CPUC.[26]

PG&E's proposed tariff language not only acknowledges the role of the CCA but also ensures that customers are on notice that relevant information will be shared with the CCA. Comparable provisions should be incorporated into any interconnection or delivery service tariffs adopted by the other California IOUs.

While only a limited number of states have retail generation choice, and therefore limited examples of tariff language highlighting the role of generation competition, there is precedent in other states for language highlighting the role of non-IOU generation providers. For example, American Electric Power (AEP) Ohio has clear language in its large load tariff highlighting the role of competitive service providers. Schedule DCT, AEP Ohio's Data Center tariff reads:

[26] A.24-11-007, Attachment A-4.

"Customers receiving service under this schedule may select competitive service from a CRES [Competitive Retail Electric Service] Provider or Standard Offer Service."[27]

Beyond ensuring that adequate information is provided both to new customers regarding the role of the CCA and to the CCAs regarding new customers they will serve, as proposed in the PG&E Rule 30 proceeding (A.24-11-007), at this time, CCAs do not seek to dictate or modify the substantive terms of the IOU tariffs. CCA Governing Boards retain sole governing and ratemaking authority over the terms and conditions of their generation service, and CCA Governing Boards will set the terms and conditions of service to large load or data center customers. Service to new customers will be consistent with cost of service as well as the requirements of section 366.2 (c)(4) requiring universal access, reliability and equitable treatment of all classes of customers.[28]

As CCAs consider developing new terms and conditions for data center customers, they are also considering provisions adopted in other states including minimum service length, prepayment of contract costs, minimum demand charges, and other risk-mitigation mechanisms. As the needs of each CCA will vary, so will the necessary terms and conditions to meet the needs of their new and existing customers.

VIII. QUESTION 7: What rate designs have been adopted in other states or regions for other large load customers, including for industrial heat process producers and large commercial hydrogen generation, to support electrification, beneficial load growth and load flexibility? Should these rate designs be applicable in California? If so, how?

CalCCA has no comment on this issue at this time.

[27] Ohio Power Company Tariff Book, P.U.C.O. No. 22 at 223-4, https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/AEP_Ohio_Tariff_Bookv1.pdf.

[28] Cal. Pub. Util. Code § 366.2(c)(4)(A)-(C).

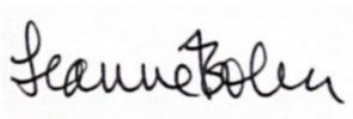
IX. QUESTION 8: Should the Commission authorize the Proposal for Consultant Contract provided in Attachment B? Should any amendments to the proposal be made?

CalCCA supports the use of an outside consultant to assist with rate design analysis

X. 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

May 11, 2026

Docket No. R.25-02-005
Exhibit No. _____
Date May 12, 2026
Witness Brian Dickman

TRACK 2 DIRECT TESTIMONY OF BRIAN DICKMAN ADDRESSING THE STAFF REPORT AND PROPOSALS ON PRE-2019 BANKED RENEWABLE ENERGY CREDITS ON BEHALF OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

ORDER INSTITUTING RULEMAKING TO UPDATE AND REFORM ENERGY RESOURCE RECOVERY ACCOUNT AND POWER CHARGE INDIFFERENCE ADJUSTMENT POLICIES AND PROCESSES

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I.! INTRODUCTION AND SUMMARY

The California Community Choice Association (**CalCCA**)[1] presents this Track 2 Direct Testimony Addressing the Pre-2019 Banked REC Staff Report in the ***! "#$"% &()*)+)* , % +./ 01* , %2%3 4#0)$%0' #% $52"/ %6' $", 7% $(2+"8$% 829"7% 882+')%0' #% ; 2<$"%>0", $%&#*5$"$' 8$%#?+()/ $')%2.*8*$(%0' #%"28$(($(%*** (**OIR**). This testimony was prepared on behalf of CalCCA by Brian Dickman, Partner, NewGen Strategies and Solutions, LLC. Mr. Dickman's qualifications are set forth in Attachment B of his Track 2 Direct Testimony.[2]

In their Opening and Reply Testimony, Pacific Gas and Electric Company (**PG&E**), Southern California Edison Company (**SCE**), and San Diego Gas & Electric Company (**SDG&E**)[3] (collectively, **the Joint IOUs**) argue against providing Later Departing Customers[4] compensation for renewable energy credits (**RECs**) generated prior to January 1, 2019, and banked for later use (**Pre-2019 Banked RECs**) that were paid for in part by those Later Departing Customers when they were bundled customers. The Joint

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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, Peninsula Clean Energy, 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, and Valley Clean Energy.

[2] Rulemaking (**R.**) 25-02-005, !"#$%& '& ()"*$+& !*,+)-./0& .1& 2")#/& ()$%-#/& ./& 2*3#41& .1& +3*& 5#4)1."/)#&5.--6/)+0&53.)$*&7,,.$)#+). / (Mar. 2, 2026) (CalCCA-Dickman Direct Testimony).

[3] 8.)/+& 9:*/)/;& !*,+)-./0& .1& <#$)1)$& =#,&#/>& ?4*$+")$& 5.-:#/0& A.6+3*"/& 5#4)1."/)#& ?>),./& 5.-:#/0&#/>&A#/& ()*;.&=#,&B& ?4*$+")$& 5.-:#/0, R.25-02-005 (Mar. 2, 2026) (Joint IOU Opening Testimony); 8.)/+& C*:40& !*,+)-./0& .1& <#$)1)$& =#,&#/>& ?4*$+")$& 5.-:#/0& A#/& ()*;.&=#,&B& ?4*$+")$& 5.-:#/0&#/>&A.6+3*"/& 5#4)1."/)#& ?>),./& 5.-:#/0, R.25-02-005 (Mar. 23, 2026) (Joint IOU Reply Testimony).

[4] This testimony uses the terms Previously Departed Customers, Then-Bundled Customers, Later Departing Customers, and Current Bundled Customers as they were defined in the CalCCA-Dickman Direct Testimony. A**&CalCCA-Dickman Direct Testimony at 1, 10-16.

IOUs argue that Pre-2019 Banked RECs should be valued at $0 when used for Current Bundled Customer Renewables Portfolio Standard (**RPS**) compliance.

In my Direct and Rebuttal Testimony I set forth CalCCA's proposal to value Pre-2019 Banked RECs using the current year RPS Market Price Benchmark (**MPB**). Specifically, when an IOU uses Pre-2019 Banked RECs for compliance, those RECs would be valued at the current-year RPS MPB, and a credit equal to the total value of those RECs would be recorded to the PCIA vintage subaccount corresponding to the year in which the REC was generated and banked. Current Bundled Customers would be charged the market value of those RECs but would simultaneously receive a credit through the PCIA equal to their own load ratio share of that value. The net effect is that Current Bundled Customers pay only for Later Departing Customers' share of the RECs and nothing more.

This testimony responds to the Energy Division Staff Report and Proposals on Pre-2019 Banked Renewable Energy Credits (**Staff Report**) that was attached to the March 27, 2026, Administrative Law Judge's (**ALJ**) Ruling Issuing Staff Report (**ALJ Ruling**).[5] CalCCA appreciates Staff's acknowledgement in the Staff Report that the current treatment of Pre-2019 Banked RECs raises legitimate indifference concerns and that a $0 valuation would leave a subset of unbundled customers without benefit for RECs they partly funded.[6] However, CalCCA does not support any of the four options for valuing Pre-2019 Banked RECs that Staff presents because they are not designed to estimate the compliance value Staff itself identifies as the appropriate basis for valuation.[7] Rather, Staff's options are

[5] A** 7> -)/),+"#+)D*&E#F&86>;*G,&C64)/;&H,,6)/;&A+#11&C*:."+, R.25-02-005 (Mar. 27, 2026), at 2-3.

[6] A**&Staff Report at 7 ("the Joint IOU proposal to value pre-2019 RECs at $0 would result in a subset of unbundled customers receiving no benefit for RECs they partly paid for when they were bundled customers. As a result, that subset of unbundled customers would no longer be indifferent.").

[7] A**&)>. at 8 ("ED staff observe that these banked RECs – which were funded in part by later departed customers – do have value in that they can be used for compliance.").

presented as a compromise designed to limit the financial impact on Current Bundled Customers relative to the status quo — a different objective than achieving indifference.

Based on my review of the Staff Report, I make the following recommendations:

- The Commission should adopt CalCCA's proposal to value Pre-2019 Banked RECs at the current-year RPS MPB when used for Current Bundled Customer RPS compliance, with the resulting value credited to the PCIA vintage subaccount corresponding to the year the RECs were generated. The current-year RPS MPB is the best measure of the value of Pre-2019 Banked RECs because it reflects the cost the IOUs avoid by not having to procure equivalent RECs in the market. In the alternative, the Commission should direct that Pre-2019 Banked RECs be allocated to the LSEs serving Later Departing Customers as described in my Direct Testimony.
- None of Staff's four options should be adopted. Staff's Load-Share Weighted RPS MPB produces geographically differentiated prices with no basis in market fundamentals. The U.S. Department of Energy (**DOE**) REC Value reflects market conditions from more than a decade ago and was never designed as a standalone measure of REC value in the PCIA. The 50/50 Split is an arbitrary reduction to the RPS MPB. And the Adjusted Weighting Mechanism, as proposed by Staff, produces a double benefit for Current Bundled Customers and would permit the IOUs to indefinitely defer the use of Later Departing Customers' share of the Pre-2019 Banked RECs.
- If the Commission determines that Pre-2019 Banked RECs should not be valued at the current-year RPS MPB, and should not be allocated to LSEs, any

alternative methodology adopted should reflect the compliance value of those RECs, *@@the value Staff itself identifies as the appropriate basis for valuation. CalCCA proposes that if its RPS MPB or allocation proposals are not adopted, the Commission consider valuing Pre-2019 Banked RECs using a weighted formula: 90 percent of the current-year RPS MPB plus 10 percent of the market price for PCC-3 RECs. This formula reflects a blended avoided cost of market REC procurement foregone by the IOUs when they use Pre-2019 Banked RECs for compliance, weighted by the statutory compliance tier limits that govern the mix of PCC-1 and PCC-3 RECs an IOU may procure.

¥ The Commission's decision on how to value Pre-2019 Banked RECs has no bearing on the Joint IOUs' ability to use those RECs for RPS compliance. Under any of the proposals that assign a dollar value to the Pre-2019 Banked RECs, the Joint IOUs retain the full quantity of Pre-2019 Banked RECs for their own compliance use. Adopting a non-zero valuation means that Current Bundled Customers would be required to pay for Later Departing Customers' share of the value of those RECs, which is precisely what indifference requires.

II.! STAFF REPORT OVERVIEW

Energy Division provided its Staff Report on March 27, 2026, in response to proposals submitted by the Joint IOUs and CalCCA regarding how to value Pre-2019 Banked RECs in the PCIA.[8] Staff identifies the following problem statement driving the need for Commission action:

[8] The Staff Report almost exclusively references statements and documents that are not in the record of this proceeding, instead relying on parties' testimony and briefs from the utilities' 2026 ERRA Forecast cases. However, the Joint IOUs and CalCCA proposals in this case are the same as those made in the 2026

> A significant portion of departed load customers were still receiving bundled service through 2019 when pre-2019 banked RECs were generated. This raises a question of whether customer indifference will be maintained if the benefits of holding and using pre-2019 banked RECs remain entirely with the IOU, when later-departed customers paid in part for them. For example, 80% or more of SDG&E load was in bundled service in 2019 and paid the RPS adders at the time, whereas remaining banked RECs will serve to meet RPS compliance for the remaining 20% of bundled load.[9]

CalCCA appreciates Staff's acknowledgement that Pre-2019 Banked RECs provide benefits that are retained by the IOUs for the benefit of Current Bundled Customers, even though Later Departing Customers paid for a share of the costs of those RECs when they were generated. The Staff Report does not draw a conclusion on the appropriate value of Pre-2019 Banked RECs but instead presents four alternative options as potential compromises between the parties' positions.

A.! Staff's analysis of parties' positions

When analyzing the Joint IOU proposal, Staff concludes that once a REC is banked it is essentially devoid of monetary value in the sense that it can no longer be bought or sold in the market. Staff also observes, however, that banked RECs do have compliance value.[10] Staff acknowledges that any methodology that values Pre-2019 Banked RECs at more than $0 would require an additional charge to Current Bundled Customers to make the revenue requirement whole because the revenue requirement is fixed, *@@any credit provided to Later Departing Customers must be collected from Current Bundled Customers. However, Staff also concludes that the Joint IOUs' $0 value approach would

ERRA Forecast ()l*l, Joint IOUs' propose zero valuation and CalCCA proposes valuation at RPS MPB) except CalCCA also provides an alternative methodology of allocation.

9 Staff Report at 5.

10 ⊦>. at 6.

result in a subset of unbundled customers receiving no benefit for RECs they partly paid for when they were bundled customers.[11]

In its review of CalCCA's proposal, Staff acknowledges that CalCCA "makes a compelling argument" that Later Departing Customers paid for a portion of the Pre-2019 Banked RECs.[12] While Staff suggests that applying the current-year RPS MPB may overvalue those RECs because they are non-tradeable and have no direct market value once banked, the Staff Report acknowledges the banked RECs do have value in that they can be used for compliance.[13]

B.! Staff's alternative options

Rather than seek to specifically estimate that compliance value, or adopt either party's proposal, Staff presents four alternative options as potential compromises intended to reduce the impact on both bundled and unbundled customers.[14] The first three options differ with respect to the price used to value the Pre-2019 Banked RECs, but all three would credit the resulting value to the PCIA vintage subaccount corresponding to the year the RECs were generated and banked, consistent with CalCCA's proposed methodology. The four options are as follows:

Option 1 — Load-Share Weighted RPS MPB. Under this option, Pre-2019 Banked RECs would be valued as a percentage of the current-year RPS MPB, determined by the current percentage of unbundled load share in the relevant IOU service territory.

Option 2 — DOE REC Value. This option would use the DOE statewide renewable energy premium from 2011 through 2018 as a proxy for the value of Pre-2019

11 ⊧>. at 7.
12 ⊧>. at 8.
13 ⊧>.
14 ⊧>. at 9.

Banked RECs, sourced from the IOU's ERRA Forecast workpapers for the year in which the REC was generated and banked. These values generally ranged from approximately $15 to $17 per MWh.

Option 3 — 50/50 Split. This option would value Pre-2019 Banked RECs at 50 percent of the current-year RPS MPB.

Option 4 — Adjusted Weighting Mechanism. Staff describes this option as a hybrid mechanism. Under this approach, the Pre-2019 Banked RECs would be divided into two separate buckets: a bundled load share and a departed load share. The bundled load share of RECs would be valued at $0, consistent with the Joint IOU proposal, while the departed load share would be valued using any of the pricing options presented by CalCCA or Staff (*@@current RPS MPB, Load-Share Weighted RPS MPB, DOE REC Value, or 50/50 Split). Staff suggests the IOUs would have the flexibility to choose which RECs to apply toward compliance, effectively allowing them to count bundled load's share of RECs toward compliance first and avoid any charge in bundled customer generation rates. When the departed load share of RECs is used for compliance, that value would flow through the PCIA and be shared with bundled and unbundled customers, similar to the other options.

III.! STAFF'S COMPROMISE OPTIONS FOR VALUING PRE-2019 BANKED RECS DO NOT REFLECT THE VALUE OF RPS COMPLIANCE

Staff argues the value of Pre-2019 Banked RECs should be more nuanced than simply applying the current-year RPS MPB. Staff states: "A banked REC is no longer tradeable, so it has no market value because it cannot be bought or sold. However, [Energy Division] staff observe that these banked RECs — which were funded in part by later departed customers — do have value in that they can be used for compliance."[15] However,

[15] ⊩>. at 8.

Staff found that "there are compelling arguments on both sides, [and that] it could be concluded that both proposals could result in either bundled or unbundled customers no longer being indifferent. Staff is cognizant of imposing undue cost-shifts on either class of customers and suggest finding a compromise approach." [16] Therefore, rather than determining the appropriate compliance value of the RECs, Staff developed various compromise options that produce an effective price for Pre-2019 Banked RECs somewhere between CalCCA's proposal (current-year RPS MPB) and the Joint IOUs' proposal ($0).[17]

Staff seems to be motivated by the Joint IOU argument that a non-zero value for Pre-2019 Banked RECs results in a charge to Current Bundled Customers compared to the status quo of valuing these RECs at $0.[18] But as Staff also acknowledges, continuing the status quo means a subset of unbundled customers will receive no benefit for RECs they partly paid for when they were bundled customers, which is contrary to California statute.

Figure 1 below illustrates the effect of each of Staff's proposals in terms of the effective price for Pre-2019 Banked RECs that would be conveyed to unbundled customers. Each option is calculated assuming the current RPS MPB is equal to the 2026 Forecast RPS MPB of $62.45/MWh.

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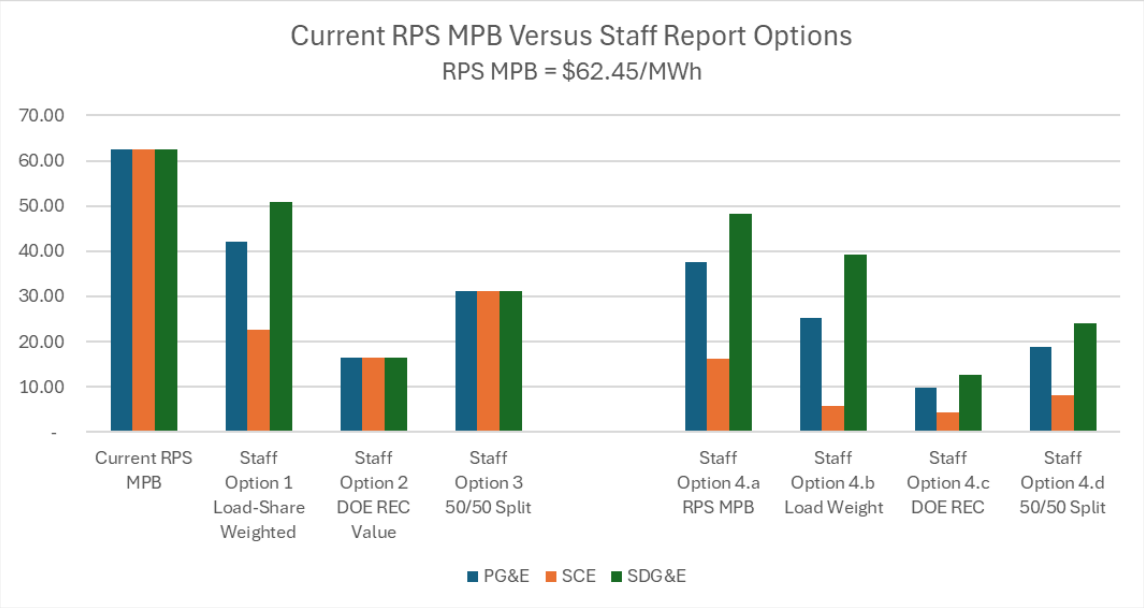
[16] ⊧>. at 9.

[17] Note that Staff Option 2 currently results in a price between CalCCA's and the Joint IOUs' proposals, but that will no longer be the case if the RPS MPB drops below $17 per MWh in the coming years (as seen in Figure 2 below).

[18] Staff Report at 7.

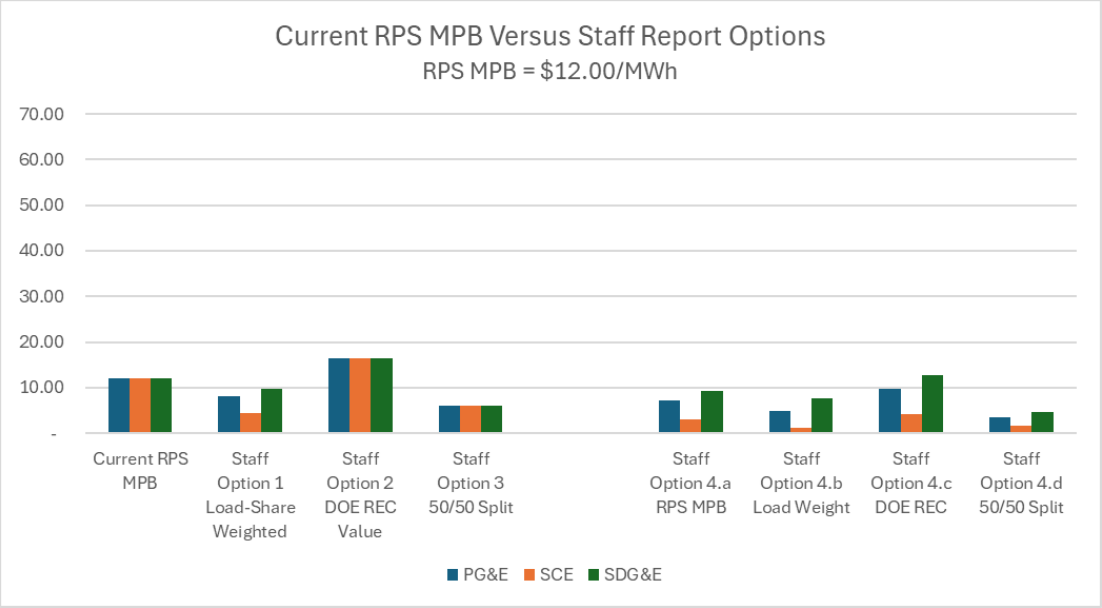
Figure 1 – Current RPS MPB Versus Staff Report Options



While the 2026 Final RPS MPB and 2027 Forecast RPS MPBs have not yet been issued, RPS pricing has in general substantially decreased since the 2026 Forecast RPS MPB of $62.45 was issued by Energy Division in October 2025.[19] Figure 2 below illustrates the effect of each of Staff's proposals in terms of the effective price for Pre-2019 Banked RECs that would be conveyed to unbundled customers, assuming a lower RPS MPB of $12/MWh.

[19] *See* S&P Global, *California RECs Face Headwinds In January, as New Bill May Drive Prices* (Feb. 10, 2026), https://www.spglobal.com/energy/en/news-research/latest-news/energy-transition/021026-california-recs-face-headwinds-in-january-as-new-bill-may-drive-prices#.

Figure 2 – Lower RPS MPB Versus Staff Report Options



CalCCA understands that Staff's proposals are presented as compromises, but as discussed in detail below, each of Staff's four options suffers from at least one key flaw that should prevent it from being adopted by the Commission.

A. Option 1 — Load-Share Weighted RPS MPB

Staff's first option would weigh the current-year RPS MPB by the current percentage of unbundled load in each IOU service territory. Staff explains that this option is intended to moderate the impact on a shrinking pool of bundled customers by reducing the credits departed load would receive. However, this approach produces a counterintuitive result: the price used to value banked RECs varies by IOU service territory, even for RECs with identical characteristics.

Using each IOU's 2026 PCIA workpapers, CalCCA calculated the 2026 unbundled load shares for PG&E, SCE, and SDG&E to be approximately 67 percent, 36 percent, and 82 percent, respectively. Applying Staff's Option 1 at a current RPS MPB of $62.45/MWh

produces the effective prices by service territory shown in Table 1 (and reflected in Figure 1 above).

Table 1 – Load-Share Weighted RPS MPB by IOU Service Territory

IOU	Unbundled Load Weight	RPS MPB ($/MWh)	Staff Option 1 Price ($/MWh)
PG&E	67%	$ 62.45	$ 42.02
SCE	36%	$ 62.45	$ 22.55
SDG&E	82%	$ 62.45	$ 50.92

As Table 1 demonstrates, a Pre-2019 Banked REC held by SDG&E would be valued at approximately $50.92/MWh in 2026, while an identical REC held by SCE would be valued at approximately $22.55/MWh, a difference of more than $28/MWh solely because SDG&E has a higher proportion of departed load in its service territory. There is no basis in market fundamentals for this disparity. Given that the market price for a REC in California is not differentiated by geography, it is counterintuitive to conclude that a banked REC held by SDG&E is worth more than a banked REC held by SCE simply because SDG&E has more departed load in its service territory. Staff argues that weighting the RPS MPB by the current load share would "promote proportionate financial impact on the shrinking pool of bundled customers in today's market realities."[20] In practice, however, Staff's Option 1 does the opposite. The smaller the pool of Current Bundled Load in a given service territory, the higher the effective price used to value banked RECs.

B.! Option 2 — DOE REC Value

Staff's second option would use the "DOE statewide renewable energy contract value" from the year the REC was generated and banked as a proxy price.[21] As Staff notes,

[20] Staff Report at 10.

[21] ⊦>.

the DOE REC value was one of the inputs incorporated into the RPS premium calculation under the PCIA framework adopted in Decision (D.) 11-12-018,[22] where it was "recognized as the best representative value for the statewide RPS market among alternatives that could be determined at the time."[23] Staff describes the typical DOE REC value prior to 2019 as ranging from roughly $15 to $17.[24] However, as D.11-12-018 makes clear, the DOE REC value was never intended to represent the standalone value of a REC — it was only one component of a weighted average benchmark that also incorporated IOU resource data.[25] When combined with PG&E's contract data, for example, the RPS premium used to value RECs in the PCIA ranged from $24 to $66 for the years 2013 through 2018.[26] Staff does not explain why only one component and not all of the RPS premium calculation approved in D.11-12-018 should serve as a proxy for valuing Pre-2019 Banked RECs.

Moreover, the DOE REC value reflects historical market conditions from more than a decade ago, not the value of RPS compliance today. In D.18-10-019, the Commission adopted The Utility Reform Network's (**TURN**) proposal to abandon reliance on the published DOE price and instead value RPS attributes based on the prices of purchases and sales of renewable energy by the IOUs, CCAs, and energy service providers.[27] At that time, TURN criticized the method adopted in D.11-12-018 as being inadequate because it did

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22 D.11-12-018, (*$),). /&7>. :+)/ ;&( )"*$+&7$$*, ,&C*1." - ,, R.07-05-025 (Dec. 1, 2011).

23 Staff Report at 10.

24 H>.

25 D.11-12-018 at 22-23, Ordering Paragraph 5.

26 CalCCA-Dickman Direct Testimony, Attachment C (PG&E response to CalCCA data request 3.04).

27 A** D.18-10-019, (*$),). /&M.>)10)/ ;&+3*&<. F*"&53#"; *&H/>)11*"*/$*&7>N6,+ - */+&M*+3.>.4. ;0, R.17-06-026 (Oct. 11, 2018), at 24 and 73.

not reflect the actual benefits an IOU would earn selling RPS resources in the market.[28] Using a price derived from conditions in 2013 to measure the benefit Current Bundled Customers receive from using those RECs in 2026 does not reflect the current market value of RPS attributes or the cost the Joint IOUs avoid by counting the RECs toward Current Bundled Customer RPS compliance.

Notwithstanding the flaws described above, Staff's Option 2 does have attributes that are preferable to Option 1. The DOE REC value is uniform across all three IOU service territories, avoiding the geographically differentiated pricing of Option 1. Under Staff's proposal the price would remain fixed until the Pre-2019 Banked RECs are exhausted, providing the benefits of administrative certainty and a fixed priced for portfolio optimization.

C.! Option 3 — 50/50 Split

Staff's third option would value Pre-2019 Banked RECs at 50 percent of the current-year RPS MPB. Staff frames this 'split-the-difference' approach as a compromise intended to "provide unbundled customers with some value, while mitigating the burden placed on bundled customers."[29] While a 50/50 split of the REC value may avoid impacting one group of customers more than another, this seeming neutrality does not overcome the fact that it does not achieve customer indifference. Staff's problem statement asks whether indifference will be maintained if the benefits of using Pre-2019 Banked RECs remain with the IOU even though Later Departing Customers paid in part for them. Rather than achieve indifference, an arbitrary division of the RPS MPB ensures that Later Departing Customers

[28] A**)>. at 38-39. Notably, TURN also explained that the DOE REC value was no longer published by that time.

[29] Staff Report at 10.

receive only a portion of the value of Pre-2019 Banked RECs that remain with Current Bundled Customers. Even though Staff describes this and the other proposals as "compromises that may better ensure indifference by reducing impacts on both sets of customers,"[30] indifference should be rooted in accuracy (i.e., compliance value) rather than based on compromises.

D.! Option 4 — Adjusted Weighting Mechanism

Staff's fourth option would divide the Pre-2019 Banked REC bank into a bundled load share and a departed load share. The bundled load share would be valued at $0, consistent with the Joint IOU proposal, while the departed load share would be valued using one of the pricing methods described above. Staff states that this hybrid mechanism "seeks to ensure departed load is credited for the share of RECs that they claim to have funded, while only requiring bundled load to buy out the share of RECs attributable to departed load, but also to provide the IOUs with the flexibility and time to adjust their procurement planning."[31]

Staff states that its weighting mechanism "ensures bundled load is only buying out the share of banked RECs attributable to departed load — and nothing more."[32] In reality, Option 4 reaches well beyond that objective. Under Staff's proposal, after segregating departed load's share of the Pre-2019 Banked RECs, any value assigned to the departed load share would still flow through the PCIA as a vintage-specific credit and the value would be shared between bundled and unbundled customers.[33] As a result, Current Bundled Customers ***<2+.#%8*9$%<2%B$' $5)(***: (1) their share of the Pre-2019 Banked

30 ╟>. at 9.
31 ╟>. at 10-11.
32 ╟>. at 11.
33 ╟>.

RECs valued at $0; and (2) a portion of the value attributed to the departed load share of the RECs. In other words, bundled customers would get their own share of the RECs for free while also receiving a portion of the credit intended to compensate departed load for its share. Because the credit for departed load's share of the RECs would flow through the PCIA under this proposal, and because bundled customers remain in the most recent PCIA vintage, these bundled customers would receive a portion (reflecting their load share) of the value they were supposed to be compensating departed load with. Under Staff's Option 4, bundled load would retain all of the Pre-2019 Banked RECs but would only partially compensate Later Departing Customers for their share.

It is CalCCA's proposal, to value Pre-2019 Banked RECs at the current-year RPS MPB when used for Current Bundled Customer RPS compliance, that most closely achieves what Staff says it is trying to accomplish with Option 4. As demonstrated in my Direct Testimony, when the value of ***0..*** Pre-2019 Banked RECs (**@@** bundled and unbundled customer shares) is credited to the PCIA vintage corresponding to the year the RECs were generated, Current Bundled Customers would be charged the market value of those RECs but would simultaneously receive a credit equal to their own load ratio share of that value.[34] The net effect is that Current Bundled Customers pay only for Later Departing Customers' share of the RECs and nothing more. Table 2 below, reproduced from my Direct Testimony, demonstrates this outcome using a hypothetical scenario in which an IOU uses banked RECs generated in 2015 with a total value of $6 million.

[34] CalCCA-Dickman Direct Testimony at Attachment A, Tables 3 and 4.

Table 2 – PCIA Rate Impact of Vintage-Specific Credit

PCIA Template (Simplified)

Vintage	UOG Legacy	2009	#####	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Cost of Portfolio ($000)																
Market Value of Portfolio ($000)																
RPS Value				($6,000)												($6,000)
Indifference Amount	$0	$0	#####	($6,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6,000)
IOU System Sales by Vintage (GWh)	70,000	70,000		63,000	59,564	56,127	52,691	49,255	45,818	42,382	38,945	35,509	32,073	28,636	25,200	
PCIA Rates	-	-		(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	
Value to Bundled Load															($2,400)	($2,400)
Value to Later Departed Load	$0	$0	#####	($327)	($327)	($327)	($327)	($327)	($327)	($327)	($327)	($327)	($327)	($327)		($3,600)
Total Banked REC Value ($000)	**$0**	**$0**	**#####**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($2,400)**	**($6,000)**
Charge to Bundled Load in Gen Rates																$6,000
Value to Bundled Load																($2,400)
Net Impact to Bundled Load Customers																$3,600

As Table 2 shows, under CalCCA's proposal, bundled customers (assumed to be 40 percent of load in this example) would be charged $6 million when the RECs are used for compliance but would simultaneously receive a credit of $2.4 million representing their own load ratio share of the banked RECs. The net payment by bundled customers is $3.6 million, which corresponds to the entire share of the RECs attributable to Later Departing Customers. Staff Option 4, however, results in the net payment by bundled customers being only a portion of the value of the Later Departing Customer share of the RECs (and Current Bundled Customers therefore receiving two benefits as described above). Applying Staff Option 4 to the example above, bundled customers would use 40 percent of the RECs at no cost and would also receive 40 percent of the value that should go to Later Departing Customers (**$@@**40 percent of $3.6 million). Therefore, bundled customers would benefit twice.

In addition to providing double benefits to Current Bundled Customers, Staff's Option 4 would permit the IOUs to sequence their use of banked RECs, applying the bundled load share toward compliance first and deferring use of the departed load share, potentially preventing Later Departing Customers from ever realizing the benefit of their

share of the Pre-2019 Banked RECs. Under CalCCA's proposal, when Pre-2019 Banked RECs are used for compliance, they are assumed to be provided proportionally from bundled and unbundled customers' shares of the bank. This proportionate approach eliminates the opportunity for the IOUs to intentionally delay utilizing the unbundled customer share of RECs while also ensuring that Current Bundled Customers only pay for the share of the RECs attributable to Later Departing Customers. The Commission should not adopt any methodology that would permit the Joint IOUs to indefinitely defer the use of departed load's share of the Pre-2019 Banked RECs, effectively allowing them to strand Later Departing Customers' share of value.

IV.! RESPONSE TO ALJ RULING QUESTIONS

The ALJ Ruling directs parties to respond to the following four questions:

1. Does the Staff Report accurately characterize party positions, parties' proposals, Commission precedent, and applicable law?
2. Which, if any, of the proposals offered by Energy Division Staff appropriately capture the value of Pre-2019 Banked RECs for the purpose of PCIA calculations? Why or why not?
3. Are there modifications that should be made to any of the methodologies proposed in the ED Staff Report that the Commission should consider when weighing the proposals for valuing Pre-2019 Banked RECs that are in the record of this proceeding?
4. Do any of the proposals offered in the Staff Report address, in whole or in part, concerns regarding the impacts of a non-zero valuation of Pre-2019 Banked RECs on RPS compliance and load serving entities' (**LSE**) procurement

strategies? Can LSEs request compliance deferrals that would further mitigate concerns about impacts on RPS compliance and procurement strategies?

The following subsections of my testimony respond to each of these questions in turn.

A.! The Staff Report Accurately Characterizes the Parties' Positions but Requires Minor Clarifications

The Staff Report generally provides an accurate characterization of the parties' positions and the applicable Commission precedent. CalCCA offers the following clarifications on two points where the Staff Report's description of the pre-2019 PCIA methodology and the vintage-crediting approach warrants additional context.

1.! How Then-Bundled Customers Paid for Pre-2019 Banked RECs

The Staff Report states that "resources in the utilities' PCIA-eligible portfolios generated these pre-2019 banked RECs and all customers who were bundled at that time paid for the RECs at the renewable adder, as determined in each utility's Energy Resource Recovery Account (ERRA) Forecast Proceeding."[35] The Staff Report also states that "[i]n the original 2011 methodology, the RPS value was charged to customers through the PCIA in the year the RECs were generated."[36] CalCCA agrees that under the original 2011 PCIA methodology Then-Bundled Customers paid for all RECs in the year the RECs were generated. However, additional context is helpful to fully understand how that payment occurred and why it is relevant to the issue before the Commission.

As described in my Direct Testimony, Then-Bundled Customers paid for Pre-2019 Banked RECs in two ways.[37] First, Then-Bundled Customers paid their load ratio share of the cost of the RPS-eligible resources in the IOU's portfolio through generation rates.

35 Staff Report at 3.
36 ⊦>. at 4.
37 CalCCA-Dickman Direct Testimony at 12-14, and Attachment A, Tables 1 and 2.

Second, Then-Bundled Customers paid the RPS MPB for Previously Departed Customers' share of the RPS attributes that remained with the IOU. This second payment occurred through the PCIA: Previously Departed Customers received a credit at the RPS MPB for their share of the RECs retained by the IOU, and Then-Bundled Customers effectively funded that credit. As a result, Then-Bundled Customers paid for all of the Pre-2019 Banked RECs, both their own share through generation rates and the Previously Departed Customers' share through the PCIA. Later Departing Customers (those leaving bundled service after the RECs were generated and banked) paid for those RECs that became Pre-2019 Banked RECs when they were Then-Bundled Customers, but have never received any benefit for those RECs, which remain in the bank and will be used to benefit Current Bundled Customers.

2.! The Vintage-Specific Credit Methodology Is Consistent with Commission-Approved Practice in PG&E's ERRA Forecasts

The Staff Report states that crediting the value of Pre-2019 Banked RECs to the PCIA vintage subaccount corresponding to the year the REC was generated and banked is "in line with the methodology for post-2018 banked RECs."[38] As I described in my Direct Testimony, PG&E used this vintage-specific crediting methodology in its 2023, 2024, and 2025 ERRA Forecast proceedings when its forecasted RPS generation fell short of its annual RPS compliance obligation, and it used banked RECs to make up the difference.[39] PG&E explained the rationale for this approach in its 2023 ERRA Forecast testimony, stating that the customers who originally paid for the surplus RPS generation are the same

[38] Staff Report at 9.

[39] CalCCA-Dickman Direct Testimony at 31-32. PG&E applied the same methodology to some Pre-2019 Banked RECs (those generated in 2018) in its 2026 ERRA Forecast case, as well, but not others (those generated in years prior to 2018).

customers who should now benefit from an accounting adjustment when those banked RECs are used for compliance.[40]

It is important to note that PG&E applied this vintage-specific credit method to banked RECs generated from 2018 – 2022)>0)%$"$%2)%"$9*2+(.7%2+')$#%(% '(2.#%; C as defined in D.19-10-001.[41] When RECs are counted as Unsold RPS pursuant to D.19-10-001, they are valued at $0 in the year of generation and then valued at the current RPS MPB when used for compliance.[42] Under this framework, when RECs are used for compliance and credited to the PCIA, the full value of the credit is spread across all PCIA vintages according to the RPS-eligible generation volume in each vintage. While the Commission approved PG&E's treatment of banked RECs in its 2023, 2024, and 2025 ERRA Forecast cases, PG&E changed its approach in its 2026 ERRA Forecast case and instead valued Pre-2019 Banked RECs at $0. The Commission noted in its 2026 ERRA Forecast Decision approving this change "on an interim basis" that it would take up Pre-2019 Banked REC valuation in a rulemaking (which it has now done in this proceeding).[43]

B.! None of Staff's Proposals Appropriately Capture the Value of Pre-2019 Banked RECs for the Purpose of PCIA Calculations

None of Staff's four options arrive at an accurate value for Pre-2019 Banked RECs because none are intended to estimate the compliance value Staff itself acknowledges should apply. As discussed in Section III above, Staff's Load-Share Weighted RPS MPB

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40 A.22-05-029, <=B?&'O'P&?CC7&J."*$#,+&<"*:#"*>&!*,+)-./0, at 11-17, lines 1-4.

41 D.19-10-001, (*$),).//&C*1)//);&+3*&M*+3.>&+.&(*D*4.:&#/>&!"6*&Q:&M#"%*+&<")$*&2*/$3-#"%,, R.17-06-026 (Oct. 10, 2019).

42 H>. at 30.

43 D.25-12-027, (*$),)./&7::".D)/;&<#$)1)$&=#,&#/>&?4*$+")$&5.-:#/0G,&'O'R&?/*";0&C*,.6"$*&C*$.D*"0&7$$.6/+&C*4#+*>&J."*$#,+&C*D*/6*&C*S6)"*-*/+&#/>&'O'R&?4*$+")$&A#4*,&J."*$#,+, Application (A.) 25-05-011, A.25-09-015 (Dec. 18, 2025) (noting that it was not possible during the expedited ERRA Forecast proceeding to consider the valuation issue and instead evaluation of the competing proposals "is appropriate for consideration in a rulemaking").

produces geographically differentiated prices with no basis in market fundamentals, valuing otherwise identical RECs differently depending on which IOU service territory holds them. The DOE REC Value reflects historical market conditions from more than a decade ago and represents only one component of the RPS premium calculation approved in D.11-12-018. The 50/50 Split is an arbitrary division of the RPS MPB with no connection to the compliance value of the RECs. And the Adjusted Weighting Mechanism produces a double benefit for Current Bundled Customers by allowing them to use their share of RECs at no cost and also giving them part of the value of Later Departing Customers' share of RECs. In addition, the Adjusted Weighting Mechanism would permit the IOUs to sequence their use of banked RECs to the IOUs' benefit. In short, each of Staff's options is intended to produce a compromise between $0 and the current RPS MPB, but compromise is not the same as indifference.

As demonstrated in my Direct and Rebuttal Testimony, Pre-2019 Banked RECs should be valued at the current-year RPS MPB when used for Current Bundled Customer RPS compliance, with the resulting value credited to the PCIA vintage subaccount corresponding to the year the RECs were generated and banked. The current-year RPS MPB is the best measure of the benefit accruing to Current Bundled Customers when the IOUs use Pre-2019 Banked RECs for compliance. When an IOU uses banked RECs to meet its RPS compliance obligation, it avoids the cost of procuring an equivalent quantity of RECs in the market. The RPS MPB is designed to reflect the price at which RPS attributes can be bought and sold in the market and is therefore the best available estimate of that avoided cost.[44] This avoided cost is the benefit Current Bundled Customers receive

[44] A** D.18-10-019 at 73; ,**&#4, .&CalCCA-Dickman Direct Testimony at 17-18.

and it is the value that should be conveyed to Later Departing Customers to maintain indifference as required by California statute.

CalCCA's alternative proposal to allocate Pre-2019 Banked RECs to the LSEs serving Later Departing Customers would also achieve the intended indifference through a different mechanism that does not require an administratively determined price for banked RECs. Under this approach, the share of Pre-2019 Banked RECs paid for by Later Departing Customers would reduce the RPS procurement need for those customers' LSEs, with an offsetting increase to the relevant IOU's RPS procurement need. Allocation is consistent with Public Utilities Code section 366.2(g), which entitles departed load customers to receive either the value of resource attributes retained by the IOU for bundled customers or an allocated share of those attributes. Either path — valuation at the current RPS MPB or allocation to LSEs — satisfies the statutory indifference requirement and ensures Later Departing Customers receive the benefit of the Pre-2019 Banked RECs for which they paid.

The Joint IOUs' Reply Testimony criticizes the allocation proposal as unimplementable because the Commission's Renewable Net Short (RNS) templates "do not establish a retail seller's RPS compliance obligation."[45] The Joint IOU's Reply Testimony goes on to state that RPS compliance reports are submitted using a compliance template produced by the Commission. The fact that the RPS compliance template produced by the Commission rather than the RNS template is where retail sellers report RPS compliance requirements does not make the CalCCA allocation proposal unimplementable.

[45] Joint IOU Reply Testimony at 34.

Based on my review of the RPS Compliance Reporting Templates provided on the Commission's website, CalCCA's proposed allocation methodology could easily be reflected in the RPS Compliance Reporting Template if the Commission approves adjusting entries to the Excess Procurement Bank quantities.[46] For the IOUs, the adjusting entry would reduce the quantity of banked RECs available to be applied toward bundled customer RPS compliance. For other LSEs, the adjusting entry would increase the quantity of banked RECs applied toward their RPS compliance in the same period. With this adjustment to the RPS Compliance Reporting Template, the share of Pre-2019 Banked RECs paid for by Later Departing Customers would effectively reduce other RPS procurement needed to meet the RPS Procurement Quantity Requirement for those customers' LSEs. To be clear, these adjustments proposed by CalCCA do not alter the IOUs' or LSEs' RPS requirements as suggested by the Joint IOUs.[47] Rather, the adjustments reflect changes in the RECs used, or available to be used, to meet the statutory requirements.

The Joint IOUs argue that CalCCA's proposed allocation of Pre-2019 Banked RECs is unreasonable because it is "akin to a second VAMO"[48] and that it will shorten IOU RPS positions and reduce CCAs' RPS compliance obligations.[49] Allocating Later Departing Customers' share of Pre-2019 Banked RECs to non-IOU LSEs is unlike VAMO because it is limited to a pre-existing quantity of excess RECs that were generated from 2011 through 2018 – it is not a second allocation of the renewable energy to be produced

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[46] A** Final 2023 RPS Compliance Report Templates available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-compliance-rules-and-process/rps-compliance-and-reporting.

A**&Joint IOU Reply Testimony at 35.

[48] H>I at 37.

[49] H>I at 38.

from the IOUs' current RPS resources. CalCCA's alternative allocation proposal is aimed at addressing an issue the IOUs, Energy Division, and other parties have raised regarding the difficulty of valuing these RECs: whether the RPS MPB—the only publicly available, Commission-vetted value that currently exists—is the right value for RECs that can only be used for compliance. While CalCCA believes the RPS MPB is the correct value, allocation avoids having to pinpoint a specific value for the Pre-2019 Banked RECs.

The Joint IOUs' Reply Testimony actually reinforces the notion that Pre-2019 Banked RECs have value that should be conveyed to Later Departing Customers. The Joint IOUs' argue that the allocation of the Pre-2019 Banked RECs would "require incremental RPS procurement that may not be economic" and that "IOU customers will face higher costs."[50] These arguments highlight the value bundled customers enjoy when the IOUs rely on Pre-2019 Banked RECs to avoid incremental RPS procurement costs.

C.! Any Alternative Method Adopted by the Commission in this Proceeding Should Recognize the Compliance Value of Pre-2019 Banked RECs

If the Commission declines to adopt CalCCA's proposal to value Pre-2019 Banked RECs at the current-year RPS MPB, any alternative methodology should be grounded in the compliance value of those RECs. Staff acknowledges that Pre-2019 Banked RECs have compliance value even if they lack direct market value.[51] The Public Advocates Office at the California Public Utilities Commission (**Cal Advocates**) similarly concludes that "Pre-2019 Banked RECs should not be valued at zero dollars because they clearly provide some quantifiable compliance value to ratepayers."[52] Cal Advocates recommends the following:

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50 H>I at 38.

51 Staff Report at 8.

52 C*:40&!*,+)-./0&.1&5#4&7>D.$#+*,&./&!"#$%&!F.&.1&+3*&9">*"&H/,+)+6+)/;&C64*-#%)/;&+.&Q:>#+*&#/>&C*1."-&?/*";0&C*,.6"$*&C*$.D*"0&7$$.6/+&#/>&<.F*"&53#";*&H/>)11*"*/$*&7>N6,+-*/+&<.4)$)*,&#/>&<".$*,,*,,&R.25-02-005 (Mar. 23, 2026), at 7.

> Pre-2019 Banked RECs can be used to meet LSEs' RPS compliance obligations and therefore provide value to ratepayers when used. Like PCC 3 RECs, Pre-2019 Banked RECs are unbundled from energy and do not contribute to an LSE's Power Content Label. However, like PCC 1 RECs, Pre-2019 Banked RECs can be used indiscriminately to meet LSE RPS obligations. The Commission should consider valuing Pre-2019 Banked RECs based on the attributes they share with PCC 1 and PCC 3 RECs.[53]

If the Commission determines Pre-2019 Banked RECs should not be valued at the full current-year RPS MPB and should not be allocated to the LSEs, those RECs should instead be valued using the following formula which generally aligns with Cal Advocates' recommendation:

[illegible]

Under this approach, 90 percent of the value would be based on the current-year RPS MPB ([illegible] the best available proxy for PCC-1 REC prices) and 10 percent would be based on a current-year PCC-3 market price, reflecting the maximum share of RPS compliance that can be satisfied with PCC-3 RECs under California statute. This alternative pricing approach would be used in conjunction with CalCCA's proposed vintage-specific PCIA credit methodology.

The resulting price reflects a blended avoided cost of IOU market procurement foregone by using Pre-2019 Banked RECs. The weighting acknowledges that Pre-2019 Banked RECs function as PCC-1 RECs for IOU compliance while also recognizing, consistent with Staff's and Cal Advocates' observations, that those RECs lack certain attributes of standard tradeable PCC-1 RECs but which can be reflected through incorporating the maximum share of PCC-3 RECs that can be used for compliance. The

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53 H>I at 8 (internal citations omitted).

90/10 weighting also acknowledges that the IOUs have some amount of flexibility to rely on PCC-3 RECs, subject to statutory limits, rather than only procuring PCC-1 RECs to meet RPS compliance requirements.

The PCC-3 market price could be determined through the same LSE survey process Energy Division uses to calculate the RPS MPB, drawing on existing transaction data already collected as part of that process. In the near term, if Energy Division determines that sufficient PCC-3 transaction data is not available to produce a reliable market price, the PCC-3 price component could conservatively be set to zero, effectively reducing the formula to 90 percent of the current-year RPS MPB until a more robust data set is available. In all events, any valuation methodology adopted by the Commission in this proceeding must recognize the compliance value of Pre-2019 Banked RECs to ensure indifference.[54]

D.! LSEs Including the Joint IOUs Can Effectively Manage Their RPS Procurement Strategies Around Any of the Options Presented in This Proceeding

ALJ Question 4 asks whether any of the proposals offered in the Staff Report address concerns regarding the impacts of a non-zero valuation of Pre-2019 Banked RECs on RPS compliance and LSE procurement strategies, and whether LSEs can request compliance deferrals to further mitigate such concerns. CalCCA's response to the first part of this question is that while a non-zero valuation of Pre-2019 Banked RECs has a financial impact on Current Bundled Customers (compared to valuing them at $0), it does not impair

[54] CalCCA acknowledges that the Staff 50/50 proposal is effectively also a percentage proposal ()l*I, valuing Pre-2019 banked RECs at 50 percent of the RPS MPB). While this 50 percent proposal at least maintains a direct relationship to the RPS MPB, the Commission must also ensure that the value conveyed to departing load equates to the Joint IOUs' avoided cost of procuring alternative RECs in the market. That value is best represented by the RPS MPB, or alternatively an allocation or the 90 percent proposal.

the Joint IOUs' ability to use those RECs for RPS compliance or to manage their procurement strategies going forward.

Under the valuation proposals presented in this proceeding — whether CalCCA's proposal, Staff's four options, or CalCCA's alternative compliance-tier-weighted approach — the Joint IOUs retain the full quantity of Pre-2019 Banked RECs for their own compliance use. None of the different valuation options require the IOUs to transfer ownership of the banked RECs, sell them to third parties, or surrender them to departing load customers. Adopting a non-zero valuation simply means that Current Bundled Customers would be required to pay for Later Departing Customers' share of the value of those RECs when they are used for compliance. Alternatively, if the Commission is unable to determine a value that ensures indifference, allocation of the Pre-2019 Banked RECs is a compelling option. This would alleviate the IOUs of the need to compensate Later Departing Customers for the financial value of the Pre-2019 Banked RECs. While it would also plainly impact the IOUs' RPS positions, the IOUs would continue to retain control of their share of the Pre-2019 Banked RECs and would have certainty about the quantity available for bundled customer use in the future.

CalCCA recognizes that adopting a non-zero value for the Pre-2019 Banked RECs in this proceeding may cause the Joint IOUs to reconsider the timing of their use of Pre-2019 Banked RECs. For example, an IOU may choose to defer its drawdown of the Pre-2019 Banked RECs in light of the valuation methodology ultimately adopted by the Commission. CalCCA does not object to the Joint IOUs having flexibility to adjust the timing of their REC bank use in response to this proceeding's outcome, provided that such flexibility is exercised within their Commission-approved RPS Procurement Plans and

subject to Commission oversight. However, as described earlier in my testimony, the Commission should not adopt any methodology that would permit the Joint IOUs to indefinitely defer the use of departed load's share of the Pre-2019 Banked RECs, effectively allowing them to strand Later Departing Customers' share of value and never provide the credit those customers are owed.

The ALJ Ruling also asks whether LSEs can request compliance deferrals to further mitigate such concerns. The answer to this question requires a legal interpretation of California statutes governing the RPS program framework and Commission decisions implementing those statutes. I understand CalCCA plans to address this issue in legal briefing, although I may address the issue in rebuttal testimony on the Staff Proposal, to the extent necessary.

This concludes my Testimony.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE DATA WORKING GROUP AND DRAFT DATA USE CASES

I. INTRODUCTION

California Community Choice Association[1] (CalCCA) appreciates the opportunity to submit these comments on the Data Working Group (DWG) and the Draft DWG Use Cases presented at the June 28, 2025, DWG meeting. The DWG was created to "examine access to data needed to facilitate customer and other entities' adoption, evaluation, and utilization of [distributed energy resources (DER)] programs and to improve DER integration with the grid."[2] CalCCA has participated in the DWG process to further this objective, representing the interests of its 24 community choice aggregator (CCA) members. Timely access to complete and accurate customer, program, and electric system data is a central concern for CCAs, who use this data to enable customer billing, forecast load, develop and deliver customer program offerings, promote rate affordability, and support community priorities.

These comments include a non-exhaustive description of CCA data access priorities and challenges, recommendations for DWG outcomes, responses to some of the questions from the

[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, Peninsula Clean Energy, 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, and Valley Clean Energy.

[2] *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking (R.) 22-11-013 (May 31, 2023), at 8: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M510/K287/510287758.PDF

May 28, 2025, DWG meeting whiteboard poll, and edits to specific data use cases. CalCCA appreciates the efforts of the California Public Utilities Commission (Commission) staff and consultants to facilitate the DWG meeting series, synthesize stakeholder input, and compile these data use cases. CalCCA offers the following recommendations to aid in the development of the DWG use cases and report:

- CCA data use cases should be prioritized for immediate and near-term implementation due to the large number of customers served by CCAs and the longstanding and critical nature of ongoing data access challenges; and
- The primary outcome of the DWG effort should be an action plan with an implementation timeline and a prioritized list of data use cases.

II. CCA DATA USE CASES SHOULD BE PRIORITIZED FOR IMMEDIATE AND NEAR-TERM IMPLEMENTATION

The DWG should prioritize CCA data use cases for immediate and near-term implementation, given the large number of customers served by CCAs and the longstanding and ongoing challenges CCAs face in obtaining timely and accurate data necessary for CCA operation from the investor-owned utilities (IOUs).[3] CCAs supply electricity to over 14,000,000

[3] California Public Utilities Code § 366.2(c)(9) establishes IOU data sharing requirements for CCAs, stating: "All electrical corporations shall cooperate fully with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs. Cooperation shall include providing the entities with appropriate billing and electrical load data, including, but not limited to, electrical consumption data as defined in Section 8380 and other data detailing electricity needs and patterns of usage, as determined by the commission, and in accordance with procedures established by the commission. The commission shall exercise its authority pursuant to Chapter 11 (commencing with Section 2100) to enforce the requirements of this paragraph when it finds that the requirements of this paragraph have been violated. Electrical corporations shall continue to provide all metering, billing, collection, and customer service to retail customers that participate in community choice aggregation programs. Bills sent by the electrical corporation to retail customers shall identify the community choice aggregator as providing the electrical energy component of the bill. The commission shall determine the terms and conditions under which the electrical corporation provides services to community choice aggregators and retail customers."

customers in more than 200 cities, towns, and counties throughout California.[4] This amounts to nearly one-third of the California Independent System Operator's (CAISO) load. While CCAs procure their own generation and create their own rates and customer programs, they rely upon IOUs to deliver electricity, meter usage, and produce monthly customer bills on their behalf. This means that the data necessary to support the development of CCA rates and customer programs are sourced from the IOUs.

Timely access to accurate and complete interval usage data from the IOUs, accessible via the Share My Data[5] or Green Button[6] platforms, is a continual challenge for many CCAs. Difficulties accessing billing quality hourly interval usage data hinders CCAs' ability to implement dynamic rates and/or programs in alignment with California's Load Management Standards.[7] Data access issues also inhibit the CCAs' ability to effectively implement and prevent dual enrollment in demand response (DR) and DER programs designed to improve resiliency, reduce costs, and provide beneficial grid services. To achieve these objectives, CCAs need access to program participation data, energization application information, load and generation integration capacity analysis data, zonal electrification information, and other data that IOUs maintain. Preventing dual enrollment in DR programs is a longstanding concern for CCAs, given the struggle to obtain complete DR program enrollment data from IOUs.

4 *See*: https://cal-cca.org/.

5 *See, for example*: https://www.pge.com/en/save-energy-and-money/energy-usage-and-tips/understand-my-usage/share-my-data.html.

6 *See*: https://www.energy.gov/data/green-button.

7 *See*: California Code of Regulations (CCR), Title 20, §§ 1623.1(b): https://govt.westlaw.com/calregs/Document/I29EE5BD09D4311EDA65FDF2B31A571F6?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).

Because CCAs do not own or operate grid infrastructure, they lack visibility into grid conditions and needs, making it challenging to design DR and DER programs to optimize available circuit capacity, enhance reliability and resiliency, or defer or avoid costly grid upgrades absent the data they need from the IOUs. CCAs require access to current and forecasted capacity availability data, anticipated new loads, locational DER data, and demand flexibility dispatch instructions and pricing information. This information will allow CCAs to develop and deploy DR and DER resources that can support the grid and provide clean energy to CCA customers at the lowest possible cost.

III. THE PRIMARY OUTCOME OF THE DATA WORKING GROUP SHOULD BE AN ACTION PLAN WITH AN IMPLEMENTATION TIMELINE AND A LIST OF PRIORITIZED DATA USE CASES

The DWG effort should culminate in an action plan, including a prioritized list of recommended data use cases, a timeline, and actionable steps to implement each use case. The action plan should be included in the final DWG report for the Commission to use as the basis for a final decision in Track One, Phase Two of the DER proceeding.[8]

CalCCA also provides short- and medium-term recommended outcomes to guide the development of specific data categories and use cases, as described below:

1. Dual enrollment:

- Short-term outcomes: Clear dual enrollment rules for non-market integrated programs and program enrollment information for each customer; Clear methodology to deal with existing dual enrollments; A

[8] *Order Instituting Rulemaking to Consider Distributed Energy Resource Program Cost-Effectiveness Issues, Data Access and Use, and Equipment Performance Standards*, R.22-11-013 (Nov. 23, 2022): https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:R2211013.

streamlined process/system for dual enrollment prevention and unenrollment.

- Use Cases: Dual enrollment prevention; evaluation, measurement, and validation.

2. Low-latency interval data and improvements:

- Short-term outcome (applies to Share My Data): Improved data granularity (15-minute interval data versus the currently hourly data), with priority for comprehensive 15-minute interval data for all residential customers;
- Short-term outcome (applies to Share My Data and Green Button): Reduced latency and improved accuracy, consistency, and completeness of advanced metering infrastructure (AMI) data.
- Medium-term outcomes (applies to Share My Data and Green Button): Improvements, such as allowing multiple users and increased stability.
- Use cases: Improve load forecasting during non-emergencies and emergencies to inform CAISO scheduling. Use 15-minute interval data to help identify customer DERs and improve customer segmenting.

3. Billing quality interval data:

- Short-/medium-term outcome: Hourly or sub-hourly billing-quality interval data with minimal latency but no later than at the end of each billing cycle.
- Use case: Enable CCAs to implement dynamic or customized hourly rates not based on the IOU's current pre-aggregated time-of-use data.

4. Improved distribution system visibility:

- Short-term outcome: Visibility into locations and types of DERs in the CCA service territory.
- Medium-term outcome: More accurate Integration Capacity Analysis maps and more complete and consistent interconnection reports.
- Use case: Improve electrification and DER project deployment, support equitable program deployment, and improve load forecasting. Improve understanding of the economics of the transition to Solar Billing Plan.

5. Identification of Virtual Net Energy Metered (VNEM) customers:

- Short-term outcome: A list of every VNEM customer and associated VNEM installation (meter ID) and share of generation the customer gets, for each CCA's service territory.
- Use case: Enable CCAs to connect VNEM system meters to customers, improving revenue modeling and short-term load forecasting.

IV. RESPONSES TO THE MAY 28, 2025, DWG MEETING WHITEBOARD POLL

CalCCA offers responses to the following whiteboard poll questions, posed at the May 28, 2025, DWG meeting:

Question: ***Should CCAs requesting access to customer-level gas consumption data be included in the Energy Data Request Portal (EDRP) and be eligible to receive this data?***

Response: Option 5 - CCAs requesting access to customer-level gas consumption data should be included in the EDRP and be eligible to receive this data on a monthly cadence at a minimum. Access to customer-level gas data supports CCAs' interest in use cases CustProgRate4A (targeted decarbonization) and CustProgRate5A (energy efficiency performance-based incentives).

Question: ***Are DER device output and charge/discharge actuals from ratepayer-incentivized equipment (i.e., SGIP) appropriate and necessary for public release?***

Response: Option 5 - DER device output and charge/discharge actuals from ratepayer-incentivized equipment are appropriate and necessary for public release. This data is important for determining DER program effectiveness at the state-wide level and should be publicly available at the census tract level.

Question: ***Is customer solar/storage project data by census tract appropriate and necessary for public release?***

Response: Option 4 - Data on customer solar and/or energy storage projects should be available for public release. While CCAs do not have data privacy concerns for releasing this data at the census tract level, it may not be necessary or more useful than data at the customer zip, city, and county level.

Question: ***Are the timelines for VNEM credits being allocated to tenant bills, and the timelines for changes appropriate and necessary for public release?***

Response: Option 3 - Account holders and tenants should have the right to know when and how much will be allocated to their bills. IOUs and CCAs should also know that information for billing, forecasting, and program design purposes. Higher-level VNEM information can be shared with the public, such as program rules. The information released for VNEM should follow the same outline as NEM.

Question: ***Should local governments be able to make aggregated data received via EDRP available to the public?***

Response: Option 4 – As long as the data are aggregated at the city level, local governments should be allowed to make the data received via EDRP available to the public. However, providing data at the zip code level or below raises privacy concerns.

V. COMMENTS ON DRAFT DATA USE CASES

CalCCA identified draft data use cases relevant to CCA data access needs. Unless otherwise noted, CalCCA generally agrees with the use case descriptions in the Draft Data Use Cases spreadsheet. Suggested edits are shown in **red**.

1. CustProgRate3A (Preventing Dual in DR/Load Modifying Program Enrollment)

The stakeholder proposed solutions should be modified to clarify the centralized DER registry recommendation and to delete a previously submitted CalCCA recommendation for CCA access to DER Management Systems (DERMS) signals. While there may be merit in using DERMS signals to provide information on DR program enrollment, the potential cost and complexity of doing so compared to other solutions make this option less viable. The stakeholder proposed solutions for this use case should be modified to include recommendations for:

- A central database of static nameplate data of DER, customer program enrollment, **and associated program dispatch rules, accessible to CCAs, IOUs, and 3rd party DRPs** (DER registry);
- A common event and enrollment tracking between load-serving entities, aggregators, State, and CAISO through a standardized schema; and
- A centralized identity management and consent tracking **system or process**.
- ~~**Access to DERMS signals which alerts CCAs when a CCA customer enrolls in IOU program (near real-time)**~~

2. CustProgRate4A (Targeted Decarbonization)

The purpose of the use case should be modified to include **transportation and** building electrification. Vehicle emissions account for a large portion of greenhouse gas (GHG) emissions and as a result, electric vehicle (EV) charging equipment, particularly for medium- and heavy-duty electric trucks, EV fleets, and public EV fast chargers, are included in decarbonization plans.

Monthly customer-level **zonal electrification data** should be added to the data elements. This information helps CCAs with targeting customers for participation in electrification and DER programs. Additionally, the following access/barriers should be modified to include the following:

- **CCAs currently receive quarterly interconnection reports, but the data is incomplete and inaccurate. The data only include behind-the-meter solar and energy storage, which can only be mapped to a service point ID about 70 percent of the time for some IOUs. The data does not include when an asset is decommissioned.**
- **IOU circuit-level integration capacity analysis data is outdated and/or inaccurate.**
- **CCAs are unable to access third-party provider or IOU data. CCAs should have a direct line of communication with the IOU, similar to the current practice for energy efficiency programs.**

3. CustProgRate6A (EE/BE/DER Program Design and Targeting)

The data requirements should include **circuit-level** data and **monthly customer-level zonal electrification** data.

4. CustProgRate11A (CCA Dynamic Rates)

Include **sub-hourly** data requirements.

5. CustProgRate12A (Explaining and Verifying VNEM Customer Bills)

Add the following use case purpose statement: **Identification of VNEM customers to improve short-term forecasting and revenue modeling, and to provide customer billing support.**

Include **customer-level** and **device-level** data requirements.

6. GridInfra3B (Short-Term Forecasting)

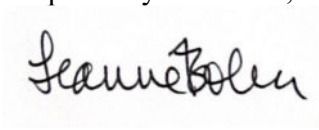
The data element listed should read "**non-**billing quality customer usage data" instead of "billing quality customer data." This data use case focuses on developing short-term, day-ahead forecasts to optimize demand response and DER dispatches for changing weather conditions. Producing billing-quality data, which requires that the data be validated before being published,

would take too long to be of value for this use case. Timeliness is more valuable than accuracy for this purpose; therefore, non-billing quality data is the appropriate data element.

VI. CONCLUSION

CalCCA respectfully submits the above informal comments for consideration of the recommendations herein.

Respectfully submitted,



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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Association of Bay Area Governments (CPUC ID 941) for Approval of the Bay Area Regional Energy Network 2028-2031 Portfolio Plan and 2028-2035 Business Plan	Application 26-03-009 (Filed March 16, 2026)
And Related Matters.	Application 26-03-010 Application 26-03-011 Application 26-03-012 Application 26-03-013 Application 26-03-014 Application 26-03-015 Application 26-03-017 Application 26-03-018 Application 26-03-019 Application 26-03-020 Application 26-03-021 Application 26-03-028 (Consolidated)

REPLY TO RESPONSES AND PROTESTS TO THE APPLICATION OF MARIN CLEAN ENERGY FOR APPROVAL OF 2028-2031 ENERGY EFFICIENCY PORTFOLIO PLAN AND 2032-2035 ENERGY EFFICIENCY BUSINESS PLAN

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May 18th, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Association of Bay Area Governments (CPUC ID 941) for Approval of the Bay Area Regional Energy Network 2028-2031 Portfolio Plan and 2028-2035 Business Plan	Application 26-03-009 (Filed March 16, 2026)
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REPLY TO RESPONSES AND PROTESTS TO THE APPLICATION OF MARIN CLEAN ENERGY FOR APPROVAL OF 2028-2031 ENERGY EFFICIENCY PORTFOLIO PLAN AND 2032-2035 ENERGY EFFICIENCY BUSINESS PLAN

1. Introduction

Pursuant to Rule 2.6(e) of the California Public Utilities Commission ("Commission," or "CPUC") Rules of Practice and Procedure the *March 18, 2026 Email Ruling Partially Granting Rule 11.6 Extension Request for Energy Efficiency Applications and Business Plans* and the *April 15, 2026 Administrative Law Judge's Ruling Consolidating Proceedings and Confirming Final Dates to File Protests, Responses and Replies*, Marin Clean Energy ("MCE") submits the following reply to the responses and protests to the Application of MCE For Approval of 2028-2031 Energy Efficiency Portfolio Plan and 2032-2035 Energy Efficiency Business Plan ("MCE

Application") filed March 16th, 2026. MCE specifically responds to the responses and protests filed with the Commission on May 1st, 2026.

In this reply, MCE states: (1) its commitment to advancing affordability solutions for customers in its energy efficiency ("EE") portfolio programs consistent with Executive Order N-5-24, Assembly Bill 3264 (Petrie-Norris, 2024), and other relevant guidance; (2) its support for workforce standards and high road jobs in EE portfolio programs (3) its belief that evidentiary hearings are not necessary at this stage in the proceeding. MCE finds EE critical to advancing equity, energy savings, decarbonization, workforce development, grid reliability and energy affordability for ratepayers. MCE remains committed to balanced, innovative, efficient and beneficial EE programs that advance local and state policy goals.

2. Background

On March 16, 2026, Bay Area Regional Energy Network ("BayREN"), Southern California Edison Company ("SCE"), Tri-County Regional Energy Network ("3C-REN"), San Diego Gas & Electric Company ("SDG&E"), Northern California Rural Regional Energy Network ("NREN"), Southern California Regional Energy Network ("SoCalREN"), Pacific Gas and Electric Company ("PG&E"), Southern California Gas Company ("SoCalGas"), San Diego Regional Energy Network ("SDREN"), Central California Rural Regional Energy Network ("CCR REN"), Peninsula Clean Energy ("PCE"), and Inland Regional Energy Network ("I-REN") and MCE all concurrently submitted for approval of their individual 2028-2031 Energy Efficiency Portfolio Plans and 2032-2035 Energy Efficiency Business Plans. MCE, as a Commission recognized "apply to administer" PA of EE programs,[1] respectfully submitted the MCE Application on March

[1] Decision ("D.")14-01-033, Ordering Paragraph ("OP") 1 at 50; D.18-05-041, OP 1 at 182; D.21-12-011 at 28-31; D.23-06-055, OP 1 at 119.

16th, 2026, concurrently with other investor-owned utility ("IOU"), community choice aggregator ("CCA") and regional energy networks ("RENs") PAs.

On March 17th, 2026, Natural Resources Defense Council ("NRDC") requested a 30-day extension to respond to submitted Applications and Business Plans. On March 18th, 2026, Administrative Law Judge Julie A. Fitch issued *March 18, 2026 Email Ruling Partially Granting Rule 11.6 Extension Request for Energy Efficiency Applications and Business Plans* partially granting the request allowing the submission of protests and responses by May 1st, 2026, and replies by May 18th, 2026. On April 15th, 2026, Administrative Law Judge Valerie U. Kao issued *April 15, 2026 Administrative Law Judge's Ruling Consolidating Proceedings and Confirming Final Dates to File Protests, Responses and Replies* ("Consolidated Ruling"). The Consolidation Ruling consolidated the review of all submitted EE Applications and Business plans for the purposes of "administrative efficiency in considering the applications of the energy efficiency portfolio administrators for their 2028-2031 portfolios and 2028-2035 business plans as required in Decision 21-05-031."[2] This reply is timely and appropriately filed.

3. MCE Supports Advancing Energy Affordability in Portfolio Programs.

MCE agrees with several parties that EE programs can and must support advancing energy affordability.[3] MCE agrees with parties that the Commission and PAs should consider Executive Order ("EO") N-5-24 it its submission and implementation of portfolio programs.[4] EO N-5-24 is a key legislative and state policy driver for MCE's Application and its reduced budget request,[5] "MCE's commitment to affordability goals is also reflected in its proposal for a 19 percent

[2] Consolidation Ruling at 1.
[3] Rising Sun Response at 4; CalChoice Response at 4-5; CEDMC Response at 8-10, 16; SDG&E Response at 4-5; Cal Advocates Protest at 13.
[4] Cal Advocates Protest at 4.
[5] *See e.g.* MCE Application at 2-3, 8; MCE Application, Exhibit 1 at 1, 5, 67-69.

reduction in its EE budget for years 2028-2031, as compared to that initially approved by the Commission in D.23-06-055."[6]

MCE agrees with parties that EE programs can and do deliver significant affordability benefits to ratepayers.[7] MCE specifically agrees with Rising Sun Center for Opportunity ("Rising Sun") that Equity segment programs specifically are a "core strategy for meeting the State's energy, climate, and affordability targets."[8] MCE argued in its Application, "The EE portfolios are an important tool the Commission should utilize to better support energy affordability for those most unable to bear this increasing burden."[9] MCE agrees with the California Efficiency + Demand Management Council ("CEDMC") that thoughtfully designed EE programs especially those with load shaping, demand management measures are often significantly cheaper and deliver greater affordability benefits to customers than the alternative resources needed absent EE.[10] Advancing affordability is one MCE's key portfolio strategies discussed throughout its Application.[11] MCE supports a greater focus on advancing energy affordability across the portfolios.

4. MCE Supports Portfolio Advancement of Workforce Standards and High Road Jobs.

MCE supports workforce standards and high road job support in the portfolios. MCE agrees with the workforce and high road job goals identified by the California State Association of Electrical Workers, Western States Council of Sheet Metal, Air, Rail, and Transportation Workers, California State Labor Management Cooperation Committee for the International Brotherhood of

[6] MCE EE Application at 8.
[7] Rising Sun Response at 4; CalChoice Response at 5; CEDMC Response at 8.
[8] Rising Sun Response at 4.
[9] MCE Application at 26 (discussing policy recommendations to strengthen energy affordability benefits from portfolio programs).
[10] CEMDC Response at 8.
[11] See e.g. MCE Application at 2-3, 8, 16, 23-26, 31, 33-34; MCE Application, Exhibit 1 at 25-27, 38-40, 53, 68, 73-74, 82, 84-86, 88, 95, 97, 123, 140-141, 150, 166, 169, 173-178, 194, 197.

Electrical Workers and the National Electrical Contractors Association, Joint Committee on Energy and Environmental Policy, and California State Pipe Trades Council (collectively the "Joint Labor Parties").[12] MCE discusses its focus on workforce standards and high road jobs in its descriptions of its Green Workforce Pathways program ("GWPP").[13]

MCE supports workforce standards and high road jobs in its contracting and administration of GWPP.[14] MCE uses the Residential Building Decarbonization Job Quality & Labor Standards Toolkit ("Toolkit") published by Rising Sun and the Bay Area Residential Decarbonization High Road Training Partnership ("HRTP") to guide its contracting and administration of GWPP.[15] Regarding contracting, "MCE outlines workforce standards requirements in each related contract it enters with its EE program implementers. MCE's EE program implementers must all agree to MCE's Terms and Conditions contract terms, which includes minimum workforce/workplace standards in compliance with applicable state, federal, local laws, regulations, ordinances and resolutions."[16] For program administration, MCE supports high road jobs in its GWPP by ensuring participating contractors demonstrate their commitment to HRTP Toolkit labor standards. MCE specifically requires contractors to ensure:

1. Contractors' starting wages align with California Department of Industrial Relations apprentice prevailing wage sheets.
2. Contractors offer fringe benefits for health care, sick leave, and paid time off.
3. Contractors offer employees a retirement savings plan.

[12] Joint Labor Parties Protest at 7 (identifying workforce standards and support for high road jobs and contractors in portfolios).
[13] *See e.g.* MCE Application, Exhibit 1 at 51-52, 58, 106-111, 153-154; MCE Application, Exhibit 2 at 30-33.
[14] MCE Application, Exhibit 1 at 109-111.
[15] *Id*.
[16] MCE Application, Exhibit 1 at 109.

4. Contractors provide continuous learning and training plans for their employees.
5. Contractors follow regional hire standards: Contractor and job seeker placements are within the same county and 50-mile standard.[17]

If contractors fail to meet minimum standards, MCE encourages contractors to reapply when compliant.[18] Additionally in 2025, MCE and its GWPP partners supported the Emerald Cities E-Contractor Academy,[19] which assists electrification industry professionals to build technical, financial and operational skills, including a session on high road contracting practices and recommendations specifically.

5. MCE Submits Evidentiary Hearings Are Not Presently Necessary.

As stated in its Application pursuant to Rule 2.1(c), MCE does not request evidentiary hearings at this time and made efforts to provide sufficient records for its Application.[20] MCE observes PAs submitted voluminous written materials in their Applications. After reviewing all submitted Responses and Protests to Applications in the consolidated proceeding, MCE finds no party identified a dispute of material fact. Further, parties, stakeholders and the Commission will have many substantive opportunities through written testimony, rebuttal testimony, briefs, data requests, ex partes and any approved workshops to analyze Application submissions and/or gather additional relevant information for the Commission's review. MCE looks forward to working with all parties and the Commission on review of its Application. If, in the alternative, the Commission determines evidentiary are necessary, MCE requests the Commission schedule the consolidated

[17] MCE Application, Exhibit 1 at 110.
[18] *Id*. at 110.
[19] *See* Emerald Cities, Bay Area Contractor Academy, available at: https://emeraldcities.org/bayareaecontractoracademy/.
[20] MCE Application at 37.

proceeding appropriately so it may issue a final decision with sufficient time for PAs to implement 2028-2031 Portfolio Plans at the start of 2028.

6. Conclusion

MCE thanks Commissioner Douglas, Administrative Law Judge Fitch and Administrative Law Judge Kao for their consideration of this reply to party protests and responses. MCE looks forward to working with the Commission, the PAs, parties, and other stakeholders on delivering beneficial EE programs that meet the needs of its customers.

Respectfully submitted,

By: */s/ Jennifer Green*
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DATED: May 18th, 2026.

California Community Choice Association

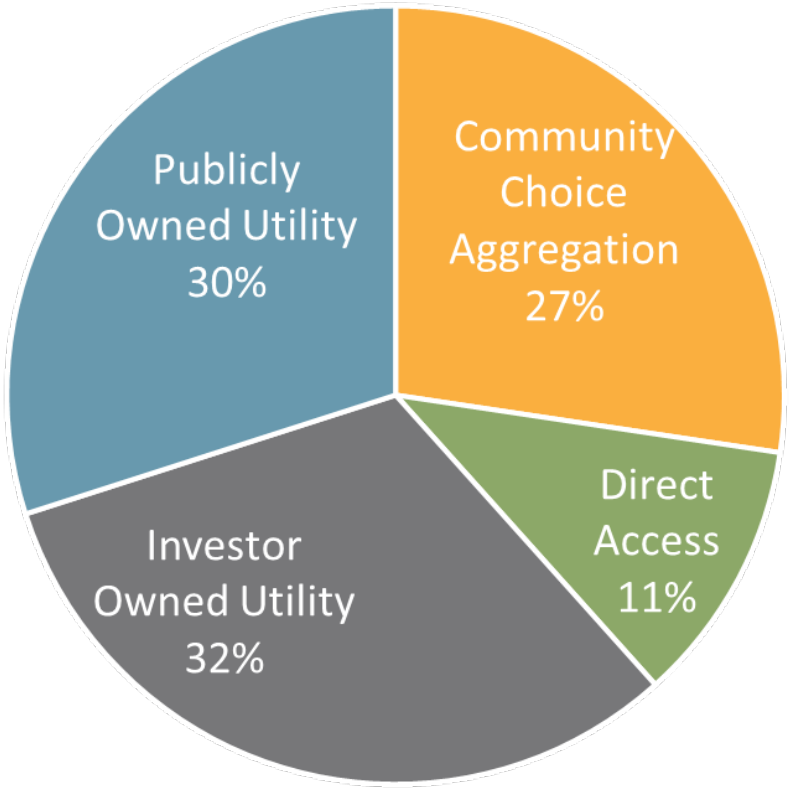
DER Orchestration Workshop
R.21-06-017

May 21, 2026

CCA Role in DER Orchestration

CCA Launch Timeline

2026 Percentage of CA Retail Load by Energy Provider



Energy Provider	2026 Deliveries (GWh)
Investor-Owned Utility	77,550
Community Choice Aggregator	66,945
Energy Service Provider (DA)	26,896
Publicly Owned Utility	73,250
Statewide Electricity Deliveries	**247,105**

Community-Centered CCA Programs

- As CCAs continue to grow and flourish in California, they are advancing innovative, industry-leading projects and programs
- Many are now focusing on DERS, including Virtual Power Plants
- Several CCAs now operate DERMS platforms to directly control customer DERs and smart appliances

Sonoma Clean Power — Your Public Electricity Provider

Alerts Through GridSavvy Rewards

Stay Cool, Save Energy, and Keep Your Neighborhood Bright With GridSavvy Rewards From Sonoma Clean Power.

GET $25 WHEN YOU ENROLL

Save Energy. Share Energy. This Summer and Beyond.

When it's really hot, everyone uses more electricity. To make sure there's enough to go around, there's an easy way to help: **Save Energy. Share Energy.** Saving energy when asked helps your whole neighborhood. When you save energy, you share energy, to help keep the lights on in the neighborhood **all summer long**.

Earn rewards by lowering your energy use when electricity use is high. By reducing electricity use during peak hours, you can help decrease the need for natural gas power plants and prevent power outages.

When you sign up for GridSavvy Rewards, you'll get paid for helping us power the electric grid with more local, clean energy. SCP will send an energy saving alert when there is high demand for electricity. You choose how to reduce your energy use.

SIGN ME UP!

MCE

How to Help California's Grid? Go Virtual

At first glance, there's nothing atypical about the small gray house located on a quiet residential street in Richmond, Calif. But look further and you'll see that it's the first piece of a revolutionary new type of power plant. Unlike traditional plants, you won't find any massive cooling towers or transmission lines. That's because this electrified home is part of a virtual power plant, or VPP.

How It Works

The homes MCE is equipping to participate in its VPP are outfitted with numerous grid-smart devices that not only provide grid flexibility but also make for a better experience for the homeowner.

VPP in the News

News Release – November 3, 2025

Peninsula Clean Energy, Silicon Valley Clean Energy Jointly Launch Demand Flexibility Initiatives

Lunar Energy's Gridshare software will enable new battery and other programs to reduce customer energy bills and harmful emissions

PENINSULA CLEAN ENERGY — SILICON VALLEY CLEAN ENERGY

REDWOOD CITY/SUNNYVALE, CA – Peninsula Clean Energy (PCE) and Silicon Valley Clean Energy (SVCE) are jointly launching cutting-edge demand flexibility efforts, highlighted by a Distributed Energy Resource Management System (DERMS) that will support a range of new programs.

The DERMS is a powerful software platform that both agencies will use as a foundation to expand their clean and smart energy programs. The new platform will enable participating customers to easily, automatically and comfortably shift daily electricity use – earning them direct bill savings, while also helping to reduce grid costs and harmful emissions.

PCE and SVCE have contracted with Mountain View-based Lunar Energy for its Gridshare DERMS platform to connect, control and optimize devices located at customer sites.

ORANGE COUNTY POWER AUTHORITY — YOUR CLEAN ENERGY CHOICE

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Residential Battery Rebate Program

Power up and protect your home with a battery energy storage system

Overview | Eligibility | Resources | Application

Power Up and Reduce Electricity Costs with a Home Battery

Orange County Power Authority's (OCPA) Residential Battery Storage Rebate Program helps customers manage their energy consumption and save money by storing electricity during lower-cost, off-peak hours for use during more expensive, on-peak hours ("load shifting"). Adding battery backup can protect your home from outages and help strengthen the electric grid. A battery will also reduce greenhouse gas emissions.

Rebate amount per customer: $1,000.

Clean Power Alliance Approves New Program to Install Virtual Power Plant and Provide Low Income Customers Access to Solar Energy at No Cost

CPA CLEAN POWER ALLIANCE

Clean Power Alliance Approves New Program to Install Virtual Power Plant and Provide Low Income Customers Access to Solar Energy at No Cost

CPA will work with Haven Energy to install networked solar and battery storage systems on eligible low-income residents' homes to provide localized clean power and significant savings on customer electricity bills while managing peak energy demand

SAN JOSE CLEAN ENERGY

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PEAK REWARDS FOR SMART HOMES

Let your smart device earn you rewards!

Peak Rewards for Smart Homes makes it easy to earn rewards. Simply enroll an eligible smart device in the program and you'll automatically start earning rewards each quarter. We communicate directly with your device to make small adjustments that keep you comfortable and earn you rewards. You are always in control and can override our signals when needed.

Ava Community Energy Announces Ambitious Virtual Power Plant Initiative to Help its 2M Customers Optimize Their Energy Investments While Relieving Stress on the Grid

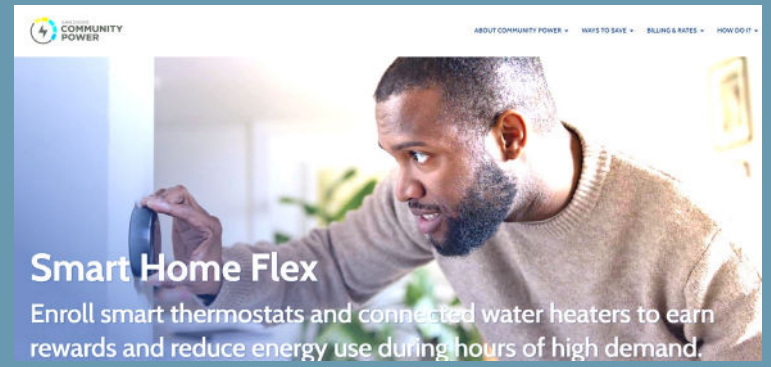
April 24, 2025

Lunar Energy's Gridshare DERMS Platform Selected to Underpin the Effort

Oakland, CA April 24, 2025 – Ava Community Energy (Ava) today announced the launch of its comprehensive Virtual Power Plant (VPP) strategy. VPPs are systems that aggregate distributed energy resources (DERS), such as electric vehicles and home batteries, so they can be controlled remotely to enhance grid reliability and lower costs.

COMMUNITY POWER

ABOUT COMMUNITY POWER | WAYS TO SAVE | BILLING & RATES | HOW DO IT



CALCCA
ADVANCING LOCAL ENERGY CHOICE

DSO Operational Roles Must be Considered Prior to Settling on a DER Orchestration Framework

A Robust Record Should be Built Before the CPUC Commits to an Orchestration Framework

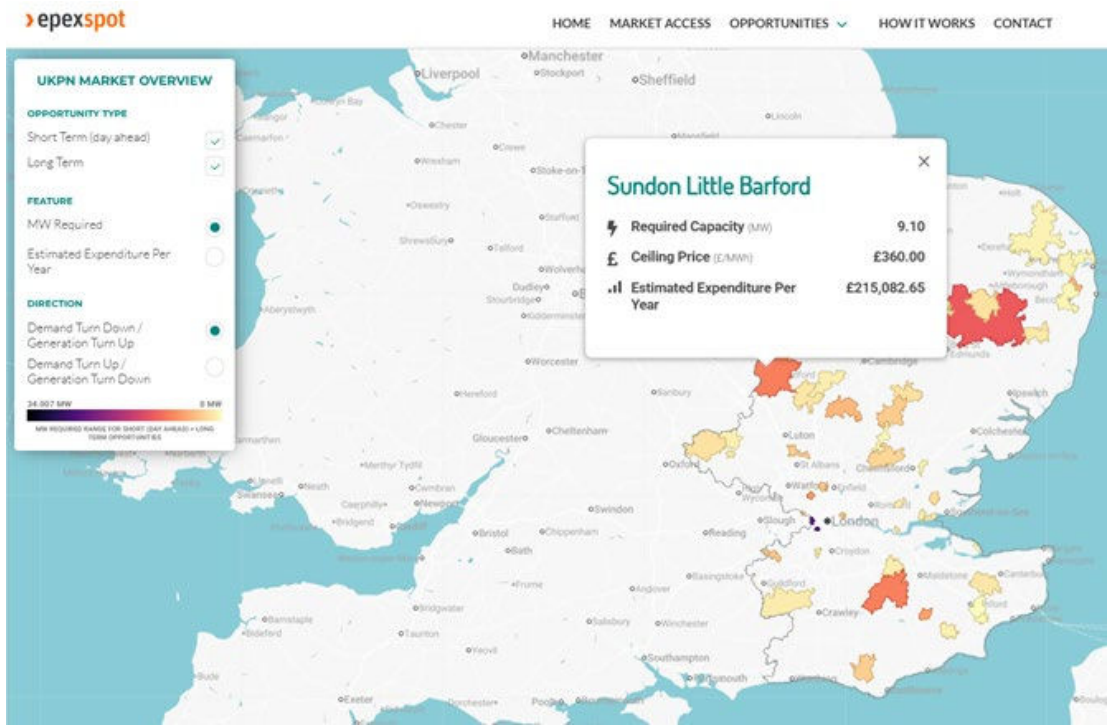
- The "build versus buy" bias inherent in the existing IOU business model must be addressed
- The CPUC should leverage FERC's rulings on market independence for RTO/ISOs to guide exploration of a DSO framework
- Worldwide, markets continue to evolve and expand (*e.g.*, the UK demand flexibility market)

Significant Recent Changes in Flexibility Markets Require CPUC Consideration

- The British demand flexibility market grew from 1.6 GW of flexibility services contracted in 2021 to 9 GW in 2025
- At least two new marketplace operators_announced partnerships with major DSOs in 2024
- The UK-based independent market operator Piclo launched its Marketplace platform across the US in 2025

Committing to a Specific DER Framework Without Further Development of the Record May Result in Higher Costs, Less Participation, and Fewer Benefits

- IOU enterprise ADMS/DERMS are not easily scalable and not designed for market administration
- The IOUs' preference for IEEE 2030.5 could limit aggregator participation and increase costs for customers wishing to participate



UK Power Network Local Flex Market Map

DER Orchestration Framework Comparison

- Provides visibility into operational needs of distribution grid and control of IOU-managed DERs
- Designed for top-down control of IOU-managed DERs rather than orchestration of third-party and CCA-managed DERs
  - Not scalable or transparent; ill-suited for orchestrating edge DERs

- Allows limited integration of non-IOU DERs
- Relying on an IOU edge DERMS limits market participation and stifles innovation

- Greater level of flexibility and scalability, reduces IOU conflicts of interest, greater transparency, and enables broad participation of DERs

- Greatest transparency and market participation, but most complex and difficult to deploy

Benefits/Risks of an Independent Flexibility Market

	Attribute	Outcome
+	Greater market neutrality	Increased participation and competition
+	More competition and innovation	Potentially lower costs and higher efficiency
+	Fewer conflicts of interest	Reduced potential for overbuilding and potentially lower costs
+	Greater transparency	Greater oversight and stakeholder trust
+	Better regional, CAISO, and LSE coordination	Broader participation and increased benefits
–	Increased complexity	Increased risk for implementation and regulatory delays
–	Requires high level of coordination with IOUs	Potential operational friction with IOUs during emergencies, depending on oversight
–	Potential data access issues with IOUs	Lack of transparent data access undermine market effectiveness
–	Potential cost duplication	Potential for increased administrative overhead in early stages of deployment

Benefits/Risks of an IOU Run Flexibility Market

	Attribute	Outcome
+	Single entity operates the grid and market	Quicker implementation
+	Tighter operational integration	More consistent alignment with safety and reliability objectives
+	Lower administrative complexity	Familiar regulatory structure, but requires new oversight and safeguards to minimize conflicts of interest
+	Easier cost recovery	Ease of financing platform deployment through retail rate recovery mechanisms
–	Greater potential for conflicts of interest	Could suppress DER participation, increase risk of overbuilding the grid, and decrease market efficiency
–	Reduced innovation	Systems and process improvements may lag technology advancements and discourage participation
–	Potential for vendor lock-in	Potential for reduced competition and interoperability
–	Less customer trust	Potential for reduced DER participation

The Commission Should First Adopt a Robust Set of Guiding Principles

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on California Advanced Electric Rate Design.	R.26-04-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ORDER INSTITUTING RULEMAKING ON CALIFORNIA ADVANCED ELECTRIC RATE DESIGN

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May 21, 2026

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V. CONCLUSION 10

SUMMARY OF RECOMMENDATIONS[1]

In responding to party Opening Comments, CalCCA urges the Commission to:

- Prioritize large load and data center issues first as recommended by many parties;
- Reject CLECA's proposal to include in scope a consideration of direct access expansion; and
- Exercise caution before revisiting or expanding the BSC as recommended by CUE.

[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 on California Advanced Electric Rate Design.	R.26-04-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ORDER INSTITUTING RULEMAKING ON CALIFORNIA ADVANCED ELECTRIC RATE DESIGN

The California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[3] in response to the *Order Instituting Rulemaking on California Advanced Electric Rate Design*[4] (OIR), dated April 9, 2026; the *E-Mail Ruling Clarifying Order Instituting Rulemaking Reply Comment Deadline of May 21, 2026*;[5] dated May 14, 2026; and the directives therein.

[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, Peninsula Clean Energy, 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, and Valley Clean Energy.

[3] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021), https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

[4] *Order Instituting Rulemaking on California Advanced Electric Rate Design*, Rulemaking (R.) 26-04-009 (Apr. 10, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M604/K677/604677976.PDF.

[5] *E-Mail Ruling Clarifying Order Instituting Rulemaking Reply Comment Deadline of May 21, 2026*, R.26-04-009 (May 14, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M606/K596/606596790.PDF.

I. INTRODUCTION

The breadth of comments submitted in response to the OIR reflects both the significance and complexity of the rate design issues before the Commission. Electrification, affordability challenges, and large load growth all present opportunities and obstacles facing California's clean energy future. Parties submitted a wide range of procedural and policy proposals, many of which underscore the need for a structured and phased scope and approach to this wide-ranging proceeding.

Opening Comments[6] present broad party consensus that the Commission should first focus on establishing an appropriate procedural framework, scope, and schedule to efficiently address the issues identified in the OIR. Notably, many parties align with CalCCA's recommendation that the proceeding should be divided into tracks and phases that recognize differing levels of urgency, statutory direction, and procedural readiness. For example, Southern California Edison Company (SCE) recommends that the broad scoped issues in the OIR will be best addressed in two concurrent priority tracks (large loads and residential customer rate design), and a third later track to evaluate longer term rate design issues.[7] San Diego Gas & Electric Company (SDG&E) similarly proposes that the proceeding "be divided into three separate tracks" covering the Base Services Charge (BSC), large loads, and general rate design.[8] Pacific Gas and Electric Company (PG&E) similarly argues that the current schedule is "inadequate to handle the wide-ranging, complex, and potentially contentious issues already identified in the OIR" and recommends five separate tracks with staggered schedules to address large loads, BSC, rate design, dynamic pricing,

[6] Opening Comments refer to the opening comments submitted into this proceeding on or about May 11, 2026.
[7] SCE Opening Comments, at 2-5.
[8] SDG&E Opening Comments, at 22-24.

and industrial heat process producer issues.[9] Nearly all of the remaining 27 sets of Opening Comments address the need for tracks, phases, and/or other procedural mechanisms to organize the proceeding's expansive scope and diverse set of issues.

Parties also broadly support additional stakeholder engagement opportunities and coordination across related proceedings. The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) recommends "additional workshop opportunities for efficient record development of complex rate design issues."[10] Enchanted Rock, LLC (Enchanted Rock) similarly recommends "using workshops to develop guiding principles" for large load tariffs.[11] The California Environmental Justice Alliance (CEJA) likewise emphasizes the breadth of issues presented in the OIR and requests the Commission "include opportunities for sufficient stakeholder input and participation through multiple workshops and comment periods and that it allows parties to develop proposals."[12]

CalCCA's Reply Comments herein focus primarily on scope, prioritization, and procedural structure, rather than on the substantive merits of any party proposals which CalCCA looks forward to addressing during the proceeding. In responding to Opening Comments, CalCCA urges the Commission to:

- Prioritize large load and data center issues first as recommended by many parties;
- Reject the California Large Energy Consumers Association's (CLECA) proposal to include in scope consideration of direct access expansion; and
- Exercise caution before revisiting or expanding the BSC as recommended by the California Coalition of Utility Employees (CUE).

9 PG&E Opening Comments, at 3-4.
10 Cal Advocates Opening Comments, at 1.
11 Enchanted Rock Opening Comments, at 1.
12 CEJA Opening Comments, at 7.

II. LARGE LOAD AND DATA CENTER ISSUES SHOULD BE ADDRESSED FIRST AS RECOMMENDED BY MULTIPLE PARTIES

The Commission should recognize the substantial consensus among parties that issues related to large loads and data centers should be prioritized in the initial phase or track of this proceeding. As CalCCA explained in Opening Comments, implementation of Senate Bill 57[13] (SB 57) and development of appropriate rate design frameworks for large load customers present urgent and time-sensitive issues. These issues have potentially significant implications for existing ratepayers, load-serving entities, and California's electrification goals.

Numerous parties agree that these issues warrant immediate attention. Cal Advocates identifies the same threshold question CalCCA raised, "whether to treat these customers as a separate customer class or continue to include these customers in the same class with other large-load customers."[14] From there, as SCE also recognizes, the statutory urgency associated with SB 57 should drive the initial track of this proceeding. SCE recommends that the Commission "concurrently prioritize a review of rate designs and tariff structures for large load, high load factor customers ("Track 1" or "Large Load Track")."[15]

Similarly, PG&E argues that "large load issues be addressed in this proceeding as the highest priority" because California is "in the midst of unprecedented growth in electric load driven, in part, by the emergence of new large load customers, including data centers."[16] PG&E further acknowledges both the opportunities and risks associated with large load growth, explaining that large loads could "drive down electricity rates for existing customers by spreading

[13] Senate Bill 57 (Padilla, Ch. 647, Stats. 2025), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202520260SB57.
[14] Cal Advocates Opening Comments, at 3.
[15] SCE Opening Comments, at 2.
[16] PG&E Opening Comments, at 2.

the fixed costs of the system across more customers,"[17] while also recognizing that these customers "may impose cost shifts on existing customers and other cost pressures across the grid."[18]

Environmental Defense Fund (EDF) likewise recommends that the Commission initially focus on "implementation of SB 57 and related data center rate design issues" because "there is already significant forecasted data center load in California that could be energized before the adoption of ratepayer-protective tariffs."[19] EDF further explains that data center cost allocation is "both an emergent and time-sensitive issue."[20]

The Utility Reform Network (TURN) also supports the urgency of addressing data center issues in this proceeding, explaining that: "[t]he unprecedented scale, concentration, and uncertainty of data-center load requires a comprehensive and forward-looking approach to rate design and cost allocation…"[21] TURN further recommends that the Commission evaluate methods of ensuring that transmission-level data center customers "pay an equitable share of societal, policy and wildfire costs currently collected in distribution rates."[22]

There is additional consensus from Advanced Energy United (AEU), Sierra Club, Enchanted Rock, and others that the Commission should prioritize implementation of SB 57. This includes prioritizing the threshold question of whether separate tariffs for data center customers are needed and by extension whether other large load tariffs are needed.[23] At the same

17 *Ibid*.
18 *Ibid*.
19 EDF Opening Comments, at 3.
20 *Ibid*.
21 TURN Opening Comments, at 2.
22 *Ibid*.
23 *See* AEU Opening Comments, at 8 (stating that "implementation of SB 57 and [Assembly Bill (AB)] 2109 and more broadly rate design for data centers or large load commercial and industrial electrification should be within the first phase."); *see also* Enchanted Rock Opening Comments, at 2 (recommending that the Commission "[e]stablish a focused track to address data center and other large

time, as CalCCA urged in its Opening Comments, the Commission must acknowledge California's unique regulatory and retail choice landscape.

As the Commission takes on the large load issues, it should also build on the record already developed in Application (A.) 24-11-007, PG&E's Rule 30 proceeding. PG&E's comments similarly state: "this proceeding should consider and incorporate applicable elements of Electric Rule 30 into this OIR's final overall large load rate design."[24] The A.24-11-007 record, in particular the *Joint Motion for Adoption of Partial Settlement Agreement* recently filed in that proceeding, provides helpful direction for the information sharing issue requested by CalCCA to be included in the scope[25] as well as "customer switching rules" identified by PG&E.[26] The partial settlement addresses each of these issues and provides a useful starting point for the Commission's consideration of these issues statewide.[27] Given the urgency and significance of establishing a large load framework in California, the Commission should prioritize these large load issues when setting the scope and schedule of this proceeding.

III. THE COMMISSION SHOULD REJECT INCLUDING IN SCOPE CLECA'S PROPOSAL REGARDING DIRECT ACCESS EXPANSION

While parties generally agree that this proceeding should focus on advanced electric rate design, affordability, electrification, and large load issues, CLECA proposes expanding the scope

load tariffs" and adopt "guiding principles for evaluating new large load tariffs that focus on reliability, measurable grid value, cost causation, and the protection of existing ratepayers from cost shifting and stranded asset risk."); *see also* Sierra Club, at 1 (urging the Commission to "prioritize development and adoption of tariffs specific to data centers" because of "the significant risk that costs to serve data centers are borne by residential and other customer classes.").

[24] PG&E Opening Comments, at 15.

[25] CalCCA Opening Comments, at 5.

[26] PG&E Opening Comments, at Appendix A-4.

[27] *See Joint Motion for Adoption of Partial Settlement Agreement of Pacific Gas and Electric Company, the Public Advocates Office, the California Community Choice Association, and Sierra Club,* A.24-11-007 (May 7, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M606/K273/606273116.PDF.

of this proceeding to include broader issues related to Direct Access and statewide caps.[28] The Commission should reject this proposal.

The OIR concerns advanced electric rate design and implementation of specific legislative directives related to affordability, electrification, and large loads. The proceeding is already exceptionally broad and complex. As numerous parties observed, the existing scope alone necessitates tracks, phases, workshops, and extended procedural schedules. Expanding the proceeding to include broader debates regarding Direct Access or retail market restructuring would unnecessarily complicate the proceeding and distract from the urgent and statutorily driven issues currently before the Commission.

Moreover, issues related to Direct Access expansion are far outside the scope necessary to resolve the questions identified in the OIR. As TURN cautions, the Commission should avoid asking parties "to litigate the same issues in multiple parallel proceedings."[29] Similarly, PG&E explains that the proceeding already contains "wide-ranging, complex, and potentially contentious issues."[30] Adding unrelated, equally complex issues that have already been addressed in more appropriate proceedings would only exacerbate those concerns.[31]

Accordingly, the Commission should reject proposals to expand the scope of this proceeding into broader Direct Access or retail competition issues and instead maintain focus on the core issues identified in the OIR.

[28] CLECA Opening Comments, at 17.
[29] TURN Opening Comments, at 1.
[30] PG&E Opening Comments, at 4.
[31] *See* Rulemaking 19-03-009, *Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access*, https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:R1903009.

IV. THE COMMISSION SHOULD REJECT CUE'S RECOMMENDATION TO REVISIT THE BSC EARLY IN THE PROCEEDING BECAUSE IT WOULD BE PREMATURE

The Commission should reject CUE's recommendation to make modifications to the BSC swiftly because CUE's claim of urgency is unsubstantiated. CUE recommends the Commission "prioritize and move swiftly on issues that will more equitably allocate fixed costs of the systems, including adding fixed costs to the [BSC]."[32] The only justification provided is that the BSC "does not include all fixed costs such as non-marginal distribution costs and, as a result, does not adequately reduce volumetric rates."[33] Indeed, the BSC does not include all fixed costs, but this statement ignores the lengthy process by which parties and the Commission reviewed proposals and reached a workable solution to comply with Assembly Bill 205[34] (AB 205). While it is reasonable to discuss BSC changes in the scope of this proceeding, there has not even been a full calendar year of BSC implementation for any electric investor-owned utility (IOU). The Commission should allow for more time to implement the BSC and discuss potential modifications after results from an initial evaluation are completed.

As CalCCA explained in Opening Comments, the Commission should prioritize issues with immediate statutory urgency and defer broader residential rate redesign and BSC modification issues to later phases of the proceeding.[35] Other parties share the view that the BSC should be discussed later in this proceeding. For example, AEU recommends that BSC-related issues "should be removed from scope or de-prioritized and placed in a later phase of the proceeding."[36] Similarly, the California Solar & Storage Association (CALSSA) argues that the

[32] CUE, at 1.
[33] *Ibid*.
[34] Assembly Bill 205 (Ch. 61, Stats. 2022), https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB205.
[35] CalCCA Opening Comments, at 12-14.
[36] AEU Opening Comments, at 2.

Commission "should not adjust the residential [BSC] until it completes the evaluation report based on one calendar year of metrics."[37] CALSSA correctly recognizes that the Commission cannot meaningfully evaluate the effectiveness or consequences of the BSC until sufficient implementation data exists. Because PG&E's implementation only recently began[38], meaningful evaluation of a full calendar year of implementation data could not begin until at least early 2027.

Similarly, the Solar Energy Industries Association (SEIA) urges caution regarding proposed modifications to income verification processes associated with the BSC. SEIA explains:

> Before the Commission proceeds any further in its consideration of the modification of the income tiers established in D.24-05-028, it must first develop, with the assistance of the IOUs, reliable cost estimates for the implementation of the alternative income verification process advanced by the Report.[39]

SEIA further warns that:

> With one of the goals of this proceeding being to make electric bills more affordable, the Commission should think twice about going forward with an income verification process that could be exorbitantly expensive for only 70 percent accuracy, at best.[40]

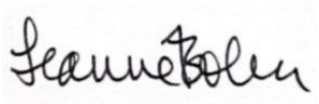
The Commission should avoid prematurely expanding the BSC or adopting potentially expensive and administratively burdensome income verification processes before the Commission has sufficient implementation data and cost information.

37 CALSSA Opening Comments, at 3.
38 BSC in PG&E service territory began in March 2026.
39 SEIA Opening Comments, at 10.
40 *Ibid*.

V. 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

May 21, 2026

Docket No. R.25-02-005
Exhibit No. _____
Date May 22, 2026
Witness Brian Dickman

TRACK 2 REBUTTAL TESTIMONY OF BRIAN DICKMAN ADDRESSING THE STAFF REPORT AND PROPOSALS ON PRE-2019 BANKED RENEWABLE ENERGY CREDITS

ON BEHALF OF

THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

ORDER INSTITUTING RULEMAKING TO UPDATE AND REFORM ENERGY RESOURCE RECOVERY ACCOUNT AND POWER CHARGE INDIFFERENCE ADJUSTMENT POLICIES AND PROCESSES

PUBLIC VERSION

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I. INTRODUCTION AND SUMMARY

The California Community Choice Association[1] (**CalCCA**) presents this Track 2 Rebuttal Testimony addressing the Energy Division Staff Report and Proposals on Pre-2019 Banked Renewable Energy Credits[2] (**Staff Report**) in the *! "#$"%&()*+)*, % - +.$/ 01*, %2%34#0)$%" #%$52"/ %6' $", 7%$(2+"8$%$829$"7%882+')%" #%2<$"%>0", $% &#*5$"$' 8$%#?+()/ $')%2.*8*$(%0' #% "28$(($(%***OIR**).% This testimony was prepared on behalf of CalCCA by Brian Dickman, Partner, NewGen Strategies and Solutions, LLC. Mr. Dickman's qualifications are set forth in Attachment B of his Track 2 Direct Testimony.[3]

In their Track 2 Opening and Reply Testimony submitted before the current round of testimony on the Staff Report, Pacific Gas and Electric Company (**PG&E**), Southern California Edison Company (**SCE**), and San Diego Gas & Electric Company (**SDG&E**)[4] (collectively, **the Joint IOUs**) argue against providing Later Departing Customers[5] any

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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, Peninsula Clean Energy, 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, and Valley Clean Energy.

[2] The Staff Report was attached to the ! "#$%$&'()'$*+, -) ., /0"1+2&, 304$%1, 5&&0$%1, 6')77, 3+89(', issued in this proceeding on March 27, 2026.

[3] Rulemaking (**R.**) 25-02-005, :();<, =, >$(+;', :+&'$#9%?, 97, @($)%, >$;<#)%, 9%, @+A)47, 97, 'A+, B)4$79(%$),B9##0%$'?,BA9$;+,!&&9;$)'$9% (Mar. 2, 2026) (CalCCA-Dickman Direct Testimony).

[4] /9$%', C8+%$%1, :+&'$#9%?, 97, D);$7$;, E)&,)%", F4+;'($;, B9#8)%?, 690'A+(%, B)4$79(%$), F"$&9%, B9#8)%?,)%", 6)%, >$+19, E)&, H, F4+;'($;, B9#8)%?, R.25-02-005 (Mar. 2, 2026) (Joint IOU Opening Testimony); /9$%', 3+84?, :+&'$#9%?, 97, D);7;, E)&,)%", F4+;'($;, B9#8)%?, 6)%, >$+19, E)&, H, F4+;'($;, B9#8)%?,)%", 690'A+(%, B)4$79(%$), F"$&9%, B9#8)%?, R.25-02-005 (Mar. 23, 2026) (Joint IOU Reply Testimony).

[5] This testimony uses the terms Previously Departed Customers, Then-Bundled Customers, Later Departing Customers, and Current Bundled Customers as they were defined in the CalCCA-Dickman Direct Testimony. 6++,CalCCA-Dickman Direct Testimony at 1, 10-16.

compensation for renewable energy credits (**RECs**) generated prior to January 1, 2019, and banked for later use (**Pre-2019 Banked RECs**) that were paid for in part by those Later Departing Customers when they were bundled customers. The Joint IOUs argue that Pre-2019 Banked RECs should be valued at $0 when used for Current Bundled Customer Renewables Portfolio Standard (**RPS**) compliance.

In my Track 2 Direct and Rebuttal Testimony submitted before the current round of testimony on the Staff Report, I set forth CalCCA's proposal to value Pre-2019 Banked RECs using the current year RPS Market Price Benchmark (**MPB**). Specifically, when an investor-owned utility (**IOU**) uses Pre-2019 Banked RECs for compliance, those RECs would be valued at the current-year RPS MPB, and a credit equal to the total value of those RECs would be recorded to the power charge indifference adjustment (**PCIA**) vintage subaccount corresponding to the year in which the REC was generated. Current Bundled Customers would be charged the market value of those RECs but would simultaneously receive a credit through the PCIA equal to their own load ratio share of that value. The net effect is that Current Bundled Customers pay only for Later Departing Customers' share of the RECs.

As directed by the Administrative Law Judge's (**ALJ**) email ruling revising the Track 2 schedule,[6] CalCCA and the Joint IOUs each submitted direct testimony addressing the Staff Report.[7] In their Direct Testimony on the Staff Report, the Joint IOUs continue to

[6] 6++, FI#)$4, 304$%1, B)%;+44$%1, F*$"+%'$)(?, J+)($%1,)%", K0('A+(, L9"$7?$%1, 'A+, :();<, :.9, D(9;++"$%1,6;A+"04+G,R.25-02-005 (Apr. 24, 2026).

[7] 6++,:();<,=,>$(+;',:+&'$#9%?,97,@($)%,>$;<#)%,!""(+&&$%1,'A+,6')77,3+89(',)%",D(989&)4&,9%,D(+I=MNO,@)%<+",3+%+.)P4+,F%+(1?,B(+"$'&,9%,@+A)47,97,'A+,B)4$79(%$),B9##0%$'?,BA9$;+,!&&9;$)'$9%G R.25-02-005 (May 12, 2026) (CalCCA-Dickman Direct Testimony on Staff Report); &++,)4&9,/9$%', >$(+;',:+&'$#9%?,97,D);$7$;,E)&,)%",F4+;'($;,B9#8)%?G,690'A+(%,B)4$79(%$),F"$&9%,B9#8)%?,)%",6)%,>$+19,E)&,H,F4+;'($;,B9#8)%?,9%,:();<,=,6')77,3+89(',)%",D(989&)4&,9%,D(+I=MNO,@)%<+",3+%+.)P4+,F%+(1?,B(+"$'&, R.25-02-005 (May 12, 2026) (Joint IOU Direct Testimony on Staff Report).

insist Pre-2019 Banked RECs should be valued at $0.[8] The Joint IOUs recommend the Commission reject any proposal, including those set forth in the Staff Report, to assign a non-zero value to the Pre-2019 Banked RECs, and they largely reiterate, reference, and incorporate the same arguments made in their Track 2 Opening and Reply Testimony. The IOUs do provide a review of "the potential workability" of Staff Proposal 4 through "certain critical modifications" including valuing the unbundled customers' portion of Pre-2019 Banked RECs at a Portfolio Content Category (**PCC**)-3 benchmark price (to be created), but caveat this analysis as "[s]trictly for the purpose of analyzing the Staff Report proposals."[9]

Like the Joint IOUs, CalCCA does not support any of the four options for valuing Pre-2019 Banked RECs as presented by Staff. None of these options are designed to estimate the compliance value of these RECs, which Staff itself identifies as the appropriate basis for valuation.[10] Rather, Staff's options are presented as a compromise designed to limit the financial impact on Current Bundled Customers relative to the status quo — a different objective than achieving indifference.

My Rebuttal Testimony identifies areas of agreement between CalCCA and the Joint IOUs, responds to the new arguments raised in the Joint IOU Direct Testimony on the Staff Report, and explains why the Joint IOUs' modifications to Staff Proposal 4 and their proposed PCC-3 benchmark should be rejected. In summary, my Rebuttal Testimony:

- Highlights that CalCCA and the Joint IOUs agree that: (1) the Staff Report proposals bear little to no relationship to the actual value for Pre-2019 Banked RECs; (2) any methodology adopted by the Commission should not provide additional credit to Previously Departed Customers; (3) Staff Proposal 2 assigning a U.S. Department of

[8] 6++,$". at 3:3-10.

[9] 6++,$". at 3:14-23-4:1-10.

[10] 6++,Staff Report at 8 ("ED staff observe that these banked RECs – which were funded in part by later departed customers – do have value in that they can be used for compliance.").

Energy (**DOE**) REC value fails to reflect current market conditions; and (4) Under Staff Proposal 4, traditional portfolio allocation balancing account (**PABA**) accounting would result in Current Bundled Customers receiving a double benefit;

- Describes how the Joint IOUs' Direct Testimony on the Staff Report does not engage with the core inequity identified by CalCCA, and acknowledged in the Staff Report, that customer indifference will not be maintained if the benefits of Pre-2019 Banked RECs remain entirely with the IOU even when Later Departing Customers paid for them;

- Responds to the Joint IOUs' new arguments by:

  - Refuting the argument that Pre-2019 Banked RECs have no market value and therefore must be valued at $0 because the PCIA methodology only assigns market value to determine above-market costs to be recovered in PCIA rates; instead, the RPS MPB is the best available proxy to determine the avoided cost of purchasing replacement RECs in the market;

  - Invalidating the Joint IOUs' argument that a $0 valuation should be adopted to promote affordability for bundled customers; instead, the $0 valuation results in bundled rates being kept lower than they should be by requiring Later Departing Customers to subsidize Current Bundled Customers' RPS compliance;

  - Rebutting the Joint IOUs' argument that CalCCA's vintage-specific crediting mechanism devalues other vintage subaccounts, given the credit discretely conveys the value of the Pre-2019 Banked RECs only to the specific groups of customers that paid for the RECs when they were generated;

- Discredits the Joint IOUs' conditional support for Proposal 4 with a PCC-3 valuation as a way to minimize bundled customer exposure by identifying: (1) the IOUs' ability to sequence their use of banked RECs would likely result in Later Departing Customers never realizing the benefit of their share of the RECs; and (2) the IOUs' characterization of Pre-2019 Banked RECs as less valuable than PCC-3 RECs ignores the fundamental compliance attribute of those RECs;

- Recommends the Commission: (1) adopt CalCCA's proposal to value the Pre-2019 Banked RECs at the RPS MPB; and (2) in the alternative, adopt CalCCA's proposal for a compliance-tier-weighted formula of 90 percent of the current year RPS MPB plus 10 percent of the PCC-3 market price.

II.! CALCCA AND THE JOINT IOUS AGREE ON CERTAIN POINTS

While CalCCA and the Joint IOUs continue to disagree on the fundamental question of whether Pre-2019 Banked RECs should be valued at $0 or at the RPS MPB, there are several points on which CalCCA and the Joint IOUs agree.

CalCCA agrees with the Joint IOUs that the Staff Report "proposes several options for assigning value based on prices that bear little or no relationship to the actual value of Pre-2019 Banked RECs."[11] As I explained in my Direct Testimony on the Staff Report, none of Staff's options are derived from an estimate of the compliance value that Staff itself identifies as the appropriate basis for valuation.[12] Rather, Staff's options are designed to produce an effective price somewhere between the Joint IOUs' proposal of $0 and CalCCA's proposal of the current-year RPS MPB.[13] While CalCCA reaches a very different conclusion than the Joint IOUs about what the actual value of Pre-2019 Banked RECs is, CalCCA agrees that Staff's options are not designed to measure that value.

CalCCA also agrees with the Joint IOUs that any methodology adopted by the Commission should not provide additional credit to customers who had already departed bundled service at the time the Pre-2019 Banked RECs were generated.[14] As I explained in my Direct Testimony, Previously Departed Customers received their share of the value of the Pre-2019 Banked RECs through the PCIA in the year the RECs were generated, valued at the then-current RPS MPB.[15] CalCCA's proposal to reflect the value of Pre-2019 Banked RECs as a vintage-specific PCIA credit will ensure customers who departed bundled service before the RECs were generated (Previously Departed Customers) do not receive any additional credit for RECs when they are used for compliance.

CalCCA agrees with the Joint IOUs that the DOE REC value under Staff Proposal 2 "ignores how market conditions have changed since the Pre-2019 Banked RECs were

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11 Joint IOU Direct Testimony on Staff Report at 2:10-12.
12 CalCCA-Dickman Direct Testimony on Staff Report at 20:17-21:12.
13 5". at 8:4-7.
14 Joint IOU Direct Testimony on Staff Report at 19:8-20.
15 CalCCA-Dickman Direct Testimony at 11:7-14:2.

generated and fails to account for how market conditions may continue to evolve in the future."[16] As I explained in my Direct Testimony on the Staff Report, the DOE REC value reflects historical market conditions from more than a decade ago, and the Commission abandoned reliance on the DOE REC value in Decision (**D.**) 18-10-019 because it failed to reflect the actual value of RPS attributes in the market.[17] The value of banked RECs at the time they are used for compliance is what matters.

Finally, CalCCA agrees with the Joint IOUs that traditional PABA accounting would result in Current Bundled Customers receiving a double benefit under Staff Proposal 4.[18] As I demonstrated in my Direct Testimony on the Staff Report, under Staff Proposal 4, bundled customers would receive their share of the Pre-2019 Banked RECs valued at $0 ***0' #%2+.#%(2%$8$*9$*** a load ratio share of the value attributed to the departed load bucket through the standard PCIA credit mechanism.[19] In their Direct Testimony on the Staff Report the Joint IOUs identify the same flaw and acknowledge that, if Proposal 4 were adopted, "it would not be equitable to further split the credits that would result from use of Pre-2019 Banked RECs in the unbundled bucket between bundled and unbundled service customers."[20]

III.! THE JOINT IOUS FAIL TO ENGAGE WITH THE CORE INEQUITY IDENTIFIED BY CALCCA AND CONFIRMED BY STAFF THAT LATER DEPARTING CUSTOMERS SHOULD RECEIVE THE BENEFIT OF RECS THEY PAID FOR

The Joint IOUs' Direct Testimony on the Staff Report continues the Joint IOUs' failure to engage with the core inequity identified by CalCCA and acknowledged by Staff.

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16 Joint IOU Direct Testimony on Staff Report at 15:18-21.
17 CalCCA-Dickman Direct Testimony on Staff Report at 12:13-17.
18 Joint IOU Direct Testimony on Staff Report at 22:9-21.
19 CalCCA-Dickman Direct Testimony on Staff Report at 14:16-16:14.
20 Joint IOU Direct Testimony on Staff Report at 22:14-17.

As Staff explained, "[a] significant portion of departed load customers were still receiving bundled service through 2019 when pre-2019 banked RECs were generated. This raises a question of whether customer indifference will be maintained if the benefits of holding and using pre-2019 banked RECs remain entirely with the IOU, when later-departed customers paid in part for them."[21] Staff found this core issue compelling enough to conclude that a $0 valuation "would result in a subset of unbundled customers receiving no benefit for RECs they partly paid for when they were bundled customers."[22] The Public Advocates Office at the California Public Utilities Commission (**Cal Advocates**) reached the same conclusion in their Track 2 Reply Testimony, observing that Pre-2019 Banked RECs "should not be valued at zero dollars because they clearly provide some quantifiable compliance value to ratepayers."[23]

As described in detail in my Track 2 Direct Testimony, Then-Bundled Customers paid for all of the Pre-2019 Banked RECs when the RECs were generated, both their own share through generation rates and Previously Departed Customers' share through the PCIA. The Joint IOUs are now using those Pre-2019 Banked RECs to meet Current Bundled Customer RPS compliance obligations, thus realizing the benefit of the RECs only on behalf of Current Bundled Customers. Under the status quo, Later Departing Customers, who paid for a share of the RECs when they were generated (as Then-Bundled Customers) but departed bundled service after the RECs were banked, received no benefits before, and will receive no benefits when the RECs are finally used for RPS compliance.

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21 Staff Report at 5.

22 5". at 7.

23 Cal Advocates Reply Testimony, R.25-02-005 (Mar. 23, 2026) at 7:17-18.

The Joint IOUs refuse to admit Later Departed Customers have never received any value from those RECs. Instead, the bulk of the Joint IOUs Direct Testimony on the Staff Report merely repeats, references, and incorporates the arguments against assigning any value to the Pre-2019 Banked RECs raised in their Opening and Reply Testimony filed earlier in this proceeding. I addressed these arguments in my Direct and Rebuttal Testimony and demonstrated that the most appropriate method to convey the benefits of Pre-2019 Banked RECs to Later Departing Customers is by applying the current RPS MPB when the RECs are used for bundled customer compliance.[24] The Joint IOUs raise three new arguments in their Direct Testimony on the Staff Report that warrant a response.

IV.! RESPONSES TO NEW ARGUMENTS RAISED IN THE JOINT IOU TESTIMONY ON THE STAFF REPORT

A.! The PCIA Methodology's Reliance on Market Value Does Not Compel a $0 Valuation

The Joint IOUs argue that Pre-2019 Banked RECs must be valued at $0 because they "have no market value."[25] They argue that Pre-2019 Banked RECs have zero value for PCIA purposes because the PCIA methodology assigns market value to the IOUs' PCIA-eligible resource portfolios to determine the above-market costs to be recovered in PCIA rates.[26] This argument distorts and misunderstands the purpose of the RPS MPB. The RPS MPB is an administratively determined proxy used to assign value to RECs *"$)0* $#%*y the IOU, *@@RECs that are held by the IOU and not transacted in the market. Because there is no observable transaction for these RECs, the Commission developed the RPS MPB and based it on the prices at which other RECs were bought and sold in the

[24], 6++, CalCCA-Dickman Direct Testimony at 18:10-14; CalCCA-Dickman Rebuttal Testimony at 22:5-13.

[25] Joint IOU Direct Testimony on Staff Report at 10:21-22.

[26] 5". at 10:21 to 11:3.

market over a defined period.[27] Applying the RPS MPB to Pre-2019 Banked RECs that have been retained by the IOU and will be used to meet Current Bundled Customer RPS compliance requirements is a natural and consistent application of these PCIA principles approved by the Commission since the inception of the renewable benchmark.

The Joint IOUs acknowledge that Pre-2019 Banked RECs "can be used for RPS compliance,"[28] but they fail to measure the value Current Bundled Customers receive when the IOUs use those RECs to satisfy bundled customer RPS obligations. Instead, the Joint IOUs insist that Pre-2019 Banked RECs have ***' 2%30.+$*** because the RECs are not tradable and are disconnected from the energy and GHG-free attributes realized when the RECs were generated.[29] But the Joint IOUs simultaneously complain that if they are unable to rely on the Pre-2019 Banked RECs for compliance purposes they would be required to undertake costly new RPS procurement that would increase costs for bundled customers.[30]

As I discussed in detail in my Rebuttal Testimony, only PCC-0 and PCC-1 RECs can be banked, and when the IOU keeps these banked RECs they "effectively live on beyond their retirement" and can be counted toward RPS compliance requirements in the future, offsetting the need for procurement of similar products later.[31] When the IOUs rely on Pre-2019 Banked RECs to satisfy RPS compliance obligations, those banked RECs displace or defer PCC-1 procurement the IOUs would otherwise need to undertake in the

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[27] 6++ D.18-10-019 at 73; &++,)4&9 CalCCA-Dickman Direct Testimony at 18:10-19:8.

[28] Joint IOU Direct Testimony on Staff Report at 12:14-21 (acknowledging that "banked RECs can be used for RPS compliance" while arguing this fact "does not cure the flaw" of equating Pre-2019 Banked RECs with PCC-1 REC values).

[29] 5".

[30] 5". at 38:9-12.

[31] CalCCA-Dickman Rebuttal Testimony at 21:3-7, citing Joint IOU Opening Testimony, Appendix B at B-5.

market. The RPS MPB is the best available proxy for that avoided cost because it reflects the price at which PCC-1 RECs can be procured in the market.[32]

B.! A $0 Valuation Does Not Promote Affordability; It Shifts Costs

The Joint IOUs continue to argue that a $0 valuation supports affordability for bundled customers. In their Direct Testimony on the Staff Report the Joint IOUs state that "certainty concerning the quantity of Pre-2019 Banked RECs subject to a zero-dollar valuation can enable the IOUs to make informed decisions regarding whether any further utilization of the bank through incremental RPS sales would promote bundled service customer affordability and reduce rates for all customers."[33] The Joint IOUs have also argued that any non-zero valuation of Pre-2019 Banked RECs "would increase bundled customer rates"[34] and would "raise costs for bundled service customers."[35] This argument conflates lower bundled customer rates with reasonable allocation of costs and benefits.

Understating the value of Pre-2019 Banked RECs by assigning them a value of $0 simply shifts a portion of the cost of bundled customer RPS compliance from Current Bundled Customers to Later Departing Customers. As described earlier, customers receiving bundled service when the Pre-2019 Banked RECs were generated (Then Bundled Customers) paid for the RECs still in the bank. The Joint IOUs are now using those Pre-2019 Banked RECs to meet RPS compliance obligations only for Current Bundled Customers. Later Departing Customers paid for a share of the RECs when they were generated but receive no benefits then or when the RECs are used for RPS compliance. If Pre-2019 Banked RECs are valued at $0, Current Bundled Customers receive the full

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32 5". at 21:13-22.
33 Joint IOU Direct Testimony on Staff Report at 28:14-18.
34 5". at 8:7-9.
35 5". at 12:22-23.

benefit of the RECs that were also paid for by Later Departing Customers, who receive no benefit. The Joint IOUs' approach keeps bundled rates lower than they should be by requiring Later Departing Customers to subsidize Current Bundled Customers' RPS compliance.

I described in my Direct Testimony that the financial consequences of valuing Pre-2019 Banked RECs are significant. For example, if all Pre-2019 Banked RECs that remain in the IOUs' REC banks are valued at the 2026 RPS MPB of $62.45/MWh, over $1.5 billion in costs would be shifted from bundled customers to departed customers.[36] It is unlikely, however, that the entirety of the IOUs' REC banks will be drawn down all at once. The annual impact on the PCIA and bundled generation rates (the cost of indifference) will depend on how many Pre-2019 Banked RECs are needed for compliance each year. In SDG&E's 2027 ERRA Forecast application filed on May 15, 2026, SDG&E explains that it "believes it will have sufficient RECs from 2027 renewable generation available to fulfill 100% of its 2027 RPS obligation" meaning it will not need to use any Pre-2019 Banked RECs in 2027.[37] That is, the cost of indifference to bundled customers will be zero in 2027 in SDG&E's service territory.

In the other IOUs' service territories, the cost of indifference in 2027 will be $1 per month or less for a household using 500 kWh per month, or up to twelve dollars per year. In SCE's 2027 ERRA Forecast testimony, [redacted]

[36] CalCCA-Dickman Direct Testimony at 16:8-11.
[37] 6++ A.26-05-009, Direct Testimony of Sheri Miller at SM-6 lines 13-14.
[38] SCE response to CalCCA Data Request 5.1, referencing A.26-05-006, SCE-01C at Table IX-45.

[redacted]. In PG&E's 2027 ERRA Forecast testimony, [redacted][40]

Valuing Pre-2019 Banked RECs is not a question of affordability because when it comes to the PCIA, either one group of customers pays more while the other group pays less, or vice versa. The Commission's aim should always be indifference. If indifference is costly, the Commission can use tools like rate amortization to manage those impacts. Here, however, it is clear the annual cost of indifference is low, and the Joint IOUs' concerns about bundled customer affordability are overstated.

C. A Vintage-Specific PCIA Credit Does Not 'Devalue' Other Vintage Subaccounts

The Joint IOUs argue that crediting the REC value to the vintage subaccount that corresponds with the REC's bank-year would "overvalue the contribution of the resources in the vintage year" and would "devalu[e] all other vintage subaccounts with resources contributing to the generation of the RECs banked in a particular vintage year."[41] This argument misconstrues the purpose of the vintage-specific PCIA credit.

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39 PG&E response to CalCCA data request 5.02, Table 8-4.

40 The calculated impact on SCE and PG&E bundled customers during 2025 uses the 2026 Forecast RPS MPB. The 2027 Forecast RPS MPB will be released in October 2026.

41 Joint IOU Direct Testimony on Staff Report at 13:3-7.

The Joint IOUs acknowledge that the Pre-2019 Banked RECs "were already valued and accounted for" under the PCIA methodology in place before 2019.[42] When the RECs were generated, their value was spread across all PCIA vintages with resources contributing to their generation to determine and allocate the value to be shared with Previously Departed Customers. In that manner, Then-Bundled Customers paid the MPB to retain Previously Departed Load's share of the RECs. When the RECs are finally used for compliance, using a vintage-specific credit allocates the benefit of the RECs to customers assigned to that vintage or later vintages. Applying the credit to a specific PCIA vintage subaccount under CalCCA's proposal does not reduce the value of any other vintage. Rather, it is a discrete credit that conveys the value of the Pre-2019 Banked RECs to the specific groups of customers that paid for the RECs when they were generated.

V.! THE JOINT IOUS' CONDITIONAL SUPPORT FOR STAFF PROPOSAL 4 IS PREMISED ON MINIMIZING BUNDLED CUSTOMER EXPOSURE, NOT ACHIEVING INDIFFERENCE

The Joint IOUs' Direct Testimony on the Staff Report identifies Proposal 4 as the only Staff option they believe could work, but only with four substantial modifications: (1) restrict the buckets to Later Departed and Current Bundled Customer load shares, excluding Previously Departed Customers; (2) fixing the bundled and unbundled bucket allocations rather than updating them year over year; (3) exempting any Pre-2019 Banked RECs used in or before 2025; and (4) replacing traditional PABA accounting with a new accounting framework to be developed through a Tier 2 Advice Letter.[43] The Joint IOUs

[42] 5". at 2:20-21.
[43] 5". at 18:18-24:9.

further propose that the unbundled bucket of RECs be valued at a PCC-3 benchmark rather than the RPS MPB or any of Staff's other pricing options.[44]

As I explained in my Direct Testimony on the Staff Report, Proposal 4 reaches well beyond Staff's stated objective of "ensur[ing] bundled load is only buying out the share of banked RECs attributable to departed load — and nothing more."[45] CalCCA identified two major flaws with Proposal 4. First, Staff's proposal would permit the IOUs to sequence their use of banked RECs, applying the bundled load share toward compliance first and deferring use of the departed load share, potentially preventing Later Departing Customers from ever realizing the benefit of their share of the Pre-2019 Banked RECs. Second, by segregating Pre-2019 Banked RECs into bundled and unbundled buckets ***0'#*** flowing the value of unbundled RECs through traditional PABA accounting, Current Bundled Customers would receive two benefits: (1) their share of the Pre-2019 Banked RECs valued at $0; and (2) a portion of the value attributed to the departed load share of the RECs. Because of these flaws, and the further discussion below addressing the Joint IOU testimony, CalCCA continues to recommend against adopting Proposal 4.

A.! The Joint IOUs Can Prevent Later Departing Customers From Ever Receiving Any Benefit

The Joint IOUs do not attempt to determine the compliance value of Pre-2019 Banked RECs. Instead, the Joint IOUs seek the option with lowest price and greatest flexibility to minimize bundled customer compensation to Later Departing Customers. The Joint IOUs acknowledge that their conditional support of Proposal 4 is based on their understanding that this option allows the IOUs to "manage the timing and manner in which

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44 5". at 24:11-19 and 25:23-27:3.

45 Staff Report at 11; &++,)4&9,CalCCA-Dickman Direct Testimony on Staff Report at 14:16-15:9.

the remaining Pre-2019 Banked RECs are used for RPS compliance" and to "better manage the risks and potential impacts associated with the increased cost of using these RECs for compliance."[46] The Joint IOUs argue that Proposal 4 should "preserve utility discretion in determining whether to use Pre-2019 Banked RECs from the bundled bucket, the unbundled bucket, or a combination of both, in meeting bundled service customers' RPS compliance requirements for the purposes of PCIA ratemaking."[47] In other words, the Joint IOUs' support for Proposal 4 is based on the flexibility it gives them to control whether Later Departing Customers ever receive any benefit. This is not a framework designed to ensure Later Departing Customers receive the value of the RECs they paid for. It is a framework designed to give the IOUs operational discretion and the ability to delay or prevent crediting Later Departing Customers.

As I described in my Direct Testimony on the Staff Report, CalCCA recognizes that adopting a non-zero value for the Pre-2019 Banked RECs in this proceeding may cause the Joint IOUs to reconsider the timing of their use of Pre-2019 Banked RECs. Under any outcome with a non-zero value, an IOU may choose to defer its drawdown of the Pre-2019 Banked RECs. CalCCA does not object to the Joint IOUs having flexibility to adjust the timing of their REC bank use in response to this proceeding's outcome, provided that such flexibility is exercised within their Commission-approved RPS Procurement Plans and subject to Commission oversight. However, Staff Proposal 4 creates a structural incentive for the IOUs to always use the bundled bucket first and defer the departed-load bucket indefinitely, potentially deferring use of Later Departing Customers' share of the bank forever.

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46 Joint IOU Direct Testimony on Staff Report at 17:9-15.

47 5". at 17:15-19.

Under CalCCA's proposal, when Pre-2019 Banked RECs are used for compliance, they are assumed to be provided proportionally from bundled and unbundled customers' shares of the bank. This proportionate approach eliminates the opportunity for the IOUs to intentionally delay using the unbundled customer share of RECs while also ensuring that Current Bundled Customers only pay for the share of the RECs previously paid for by Later Departing Customers. The Commission should not adopt any methodology that would permit the Joint IOUs to indefinitely defer the use of departed load's share of the Pre-2019 Banked RECs, effectively giving the IOUs the option to strand Later Departing Customers' share of value and never provide the credit to departed load customers who helped pay for the RECs.

B.! CalCCA's Proposal Avoids the Need to Modify PABA and PCIA Accounting and Can Be Implemented Immediately

The Joint IOUs propose structural modifications to Proposal 4 intended to: (1) restrict the buckets to Later Departed and Current Bundled Customer load shares, excluding Previously Departed Customers; (2) fix the bundled and unbundled bucket allocations rather than updating them year over year; (3) exempt any Pre-2019 Banked RECs used in or before 2025; and (4) replace traditional PABA accounting with a new accounting framework to be developed through a Tier 2 Advice Letter. CalCCA agrees that Proposal 4 must be modified if adopted by the Commission, in particular to avoid providing double benefits to any customer group (either Previously Departed Customers or Current Bundled Customers).

The Joint IOUs' solution to the double-benefit problem created by the two-bucket structure of Staff Proposal 4 is to modify PABA accounting. The Joint IOUs highlight that the traditional PABA accounting would share a portion of Later Departing Customers'

value with bundled customers, thereby giving bundled customers a double benefit under Proposal 4.[48] CalCCA agrees. The Joint IOUs propose to establish separate balancing accounts with vintaged sub-accounts to facilitate a PCIA sur-credit or annual bill credit similar to those used to account for the previous PCIA rate cap.[49] CalCCA does not object to this treatment if Proposal 4 is adopted. However, the Commission should reject the Joint IOU recommendation that the status quo ($0 value for Pre-2019 Banked RECs) remain in place until the new accounting is fully developed and implemented.[50] Reestablishing accounting procedures similar to those that have been used before does not require a delay in the effective date for assigning value to the Pre-2019 Banked RECs.

Furthermore, the need for new accounting arises only because Proposal 4 creates the double-benefit problem. As demonstrated in my Direct Testimony and discussed in my Direct Testimony on the Staff Report, CalCCA's proposed approach achieves the same net financial effect as Staff Proposal 4 without the need for new accounting frameworks. In fact, PG&E has already implemented the approach recommended by CalCCA using current PABA accounting.[51] Under the CalCCA proposal, when the value of all Pre-2019 Banked RECs (bundled and unbundled customer shares) is credited to the PCIA vintage corresponding to the year the RECs were generated, Current Bundled Customers are charged the market value of those RECs but simultaneously receive a credit equal to their own load ratio share of that value. The net effect is that Current Bundled Customers pay only for Later Departing Customers' share of the RECs and nothing more. No new balancing accounts are required.

48 5". at 22:9-23:15.
49 5". at 23:5-15.
50 5". at 24:7-9.
51 CalCCA-Dickman Direct Testimony on Staff Report at 19:16-20:14.

C.! A PCC-3 Market Price Benchmark Understates Compliance Value

The Joint IOUs propose that, if any non-zero valuation of Pre-2019 Banked RECs is adopted under modified Staff Proposal 4, the unbundled bucket should be valued at a PCC-3 benchmark rather than the RPS MPB.[52] The Joint IOUs argue that PCC-3 RECs are the "least-cost replacement product"[53] available to satisfy RPS compliance and that Pre-2019 Banked RECs are actually less valuable than PCC-3 RECs because they no longer have any GHG-free energy value and cannot be traded to third parties.[54] The Joint IOUs conclude that Pre-2019 Banked RECs offer fewer attributes than tradable PCC-3 RECs and therefore should not be valued at the PCC-1-based RPS MPB.[55]

CalCCA disagrees with the Joint IOUs' argument because the Joint IOUs ignore that Pre-2019 Banked RECs retain their original character as PCC-1 RECs for RPS compliance purposes. The Joint IOUs' characterization of Pre-2019 Banked RECs as less valuable than PCC-3 RECs ignores the fundamental compliance attribute of those RECs. Only PCC-0 and PCC-1 RECs can be banked.[56] The banked RECs retain their original PCC classification and can be counted toward an IOU's RPS compliance requirement in any future compliance period without limit, fully offsetting the need for PCC-1 procurement.[57] The fact that a Pre-2019 Banked REC can no longer be transferred to a third party and is no longer associated with a contemporaneous GHG-free energy delivery does not change its compliance classification. A Pre-2019 Banked REC counted toward an

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52 Joint IOU Direct Testimony on Staff Report at 25:23-27:3.
53 5". at 26:8-11.
54 5". at 11:15-12:21.
55 5". at 12:14-21.
56 CalCCA-Dickman Rebuttal Testimony at 21:3-7, citing Joint IOU Opening Testimony, Appendix B at B-5.
57 5". at 21:3-7, citing Joint IOU Opening Testimony, Appendix B at B-5.

IOU's RPS compliance obligation displaces or defers an equivalent quantity of PCC-1 procurement the IOU would otherwise need to undertake.

The Joint IOUs also ignore the statutory limit on the use of PCC-3 RECs for RPS compliance. California RPS statute limits PCC-3 RECs to satisfying no more than 10 percent of a load serving entity's annual RPS compliance obligation.[58]

If the Commission concludes that Pre-2019 Banked RECs should not be valued at the current-year RPS MPB, CalCCA proposes (as it did in the CalCCA Direct Testimony on the Staff Report) a compliance-tier-weighted formula that addresses the statutory PCC-3 cap directly: 90 percent of the current-year RPS MPB plus 10 percent of the PCC-3 market price.[59] This formula reflects a blended avoided procurement cost if the Joint IOUs were required to replace Pre-2019 Banked RECs through market procurement, weighted by the maximum share of compliance that can be satisfied with PCC-3 RECs under California statute.

This concludes my Testimony.

[58] CalCCA-Dickman Direct Testimony on Staff Report at 25:14-17.

[59] 5". at 24:15-26:11.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, and Other Activities for the Record Period January 1 through December 31, 2024 (U 39 E)	Application No. 25-02-013 (Filed February 28, 2025)

JOINT MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), THE PUBLIC ADVOCATES OFFICE AT THE CALIFORNIA PUBLIC UTILITIES COMMISSION, AND THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION FOR ADOPTION OF SETTLEMENT AGREEMENT

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Dated: May 22, 2026

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I. INTRODUCTION

In accordance with Rules 1.8(d) and 12.1 of the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company ("PG&E") submits this Joint Motion for Adoption of Settlement Agreement on behalf of itself, the Public Advocates Office at the California Public Utilities Commission ("Cal Advocates"), and the California Community Choice Association[1] ("CalCCA") (collectively, the "Settling Parties"). The Settlement Agreement is included as an attachment to this Joint Motion. The Settling Parties enter into this Settlement Agreement as a compromise of their respective litigation positions to resolve all disputed issues raised in the

[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, Peninsula Clean Energy, 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, and Valley Clean Energy.

above-captioned proceeding before the California Public Utilities Commission (Commission) and request that the Commission approve the Settlement Agreement as presented.

II. PROCEDURAL BACKGROUND

On February 28, 2025, PG&E filed its *Application for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, and Other Activities for the Record Period January 1 through December 31, 2024* (A.25-02-013, "Application"). Concurrent with filing the Application, PG&E also served its Prepared Testimony and workpapers, as well as responses to the Cal Advocates and CalCCA Master Data Requests (MDRs).

On April 4, 2025, Cal Advocates and CalCCA filed protests to PG&E's application. PG&E filed a reply to the protests on April 14, 2025.

The Assigned Administrative Law Judge (ALJ) held a prehearing conference on April 18, 2025, to discuss the issues of law and fact and to determine the need for hearing and a schedule for resolving the proceeding.

On May 2, 2025, Commissioner John Reynolds issued an Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo).

On September 15, 2025, Cal Advocates and CalCCA served their Testimony.

On October 24, 2025, PG&E served its Rebuttal Testimony.

On November 3, 2025, PG&E, CalCCA and Cal Advocates submitted a Joint Status Conference Statement reporting that CalCCA believed hearings may be necessary, and jointly requesting to re-open discovery and the deadline for completion of settlement discussions. In response, on November 10, 2025, the ALJ issued a ruling re-opening discovery and amending the proceeding schedule for settlement discussions, status conference and evidentiary hearing.

In accordance with the November 10, 2025 ruling, CalCCA served and PG&E responded to data requests and thereafter reported in an Updated Joint Status Conference Statement that CalCCA no longer believed hearings necessary. On December 2, 2025, the ALJ held a virtual

status conference, at which the ALJ modified the proceeding schedule to remove evidentiary hearings.

On December 15, 2025, the parties filed a Joint Motion to Enter Evidence into the Evidentiary Record, accompanied by PG&E's Motion to Seal the Evidentiary Record. Both motions were granted on December 23, 2025.

On December 22, 2025, the ALJ issued a ruling directing PG&E to prepare supplemental testimony regarding vintaging of a specific group of community choice aggregator (CCA) customers. The ruling also amended the proceeding schedule to allow time for the additional testimony.

On January 6, 2026, PG&E sent a procedural email to the ALJ. In that email, PG&E stated that (1) it would likely need more time to prepare the testimony directed in the ALJ's December 22 ruling, and (2) CalCCA would like more time to respond to the additional testimony.

On January 26, 2026, the assigned ALJ held a status conference to discuss PG&E's need for an extension. The following status conference, the ALJ issued a ruling on February 2, 2026. , In that ruling, the ALJ directed PG&E to submit supplemental testimony on March 11, 2026, and set a deadline of April 10, 2026 for CalCCA to submit reply testimony.

Subsequently, PG&E served its supplemental testimony on the March 11, 2026 deadline. In a procedural email sent on April 10, 2026, CalCCA notified the parties that it did not intend to submit reply testimony.

On April 14, 2026, PG&E, CalCCA and CalAdvocates filed a Joint Motion to Admit Supplemental Testimony and Workpapers into the Evidentiary Record in accordance with the ALJ's February 2, 2026 ruling. The ALJ granted that motion on May 12, 2026.

Cal Advocates and CalCCA have reviewed PG&E's Application, testimony, supplemental testimony, workpapers, and discovery responses, and do not object to the relief requested in PG&E's Application, subject to the terms of this Settlement Agreement.

III. SUMMARY OF SETTLING PARTIES' LITIGATION POSITIONS

A. PG&E's Position

In its Application, PG&E requested that the Commission find:

- PG&E prudently administered and managed its utility-owned generation (UOG) facilities and Qualifying Facility (QF) and non-QF contracts in compliance with all applicable rules, regulations, and Commission decisions, and Standard of Conduct (SOC) 4, including for the 2023 Belden and Caribou 1 Powerhouse outages and two 2023 Diablo Canyon Power Plan maintenance outages;
- PG&E achieved least-cost dispatch of its energy resources and economically triggered demand response programs pursuant to SOC 4;
- The entries recorded in the Energy Resources Recovery Account (ERRA) and the Portfolio Allocation Balancing Account (PABA) are reasonable, appropriate, accurate, and in compliance with Commission decisions;
- PG&E's fuel procurement and hedging activities complied with its Commission approved Bundled Procurement Plan (BPP);
- PG&E's greenhouse gas compliance instrument procurement complied with its BPP;
- That PG&E administered resource adequacy procurement and sales consistent with its BPP during the record period;
- The costs incurred and recorded in the Green Tariff Shared Renewables Memorandum Account, Green Tariff Shared Renewables Balancing Account, Disadvantaged Communities Single Family Solar Affordable Homes Balancing Account, Disadvantaged Community Green Tariff Balancing Account, Community Solar Green Tariff Balancing Account, and the Centralized Local Procurement Sub-Account were consistent with applicable tariffs and Commission directives;
- The transactions presented in PG&E's Prepared Testimony, including contract amendments related to the Alpine Solar, Agua Caliente Solar and Daggett 2 BESS

projects, and the Poblano Energy Storage Project, are reasonable and should be approved.

- That PG&E correctly calculated unrealized volumetric sales and unrealized revenue associated with Public Safety Power Shutoff events during the record period using the Commission's approved methodology.

B. Cal Advocates' Position

Cal Advocates raised in its Protest to PG&E's Application that the following four additional accounts should be included for review within the proceeding's scope:

- New System Generation Balancing Account (NSGBA);
- Modified Transition Cost Balancing Account (MTCBA);
- Tree Mortality Non-Bypassable Charge Balancing Account (TMNBCBA); and
- BioMat Non-Bypassable Charge Balancing Account (BMNBCBA).

Cal Advocates also made the following two recommendations in its September 15, 2025 testimony based on its review of PG&E's Application, Prepared Testimony, workpapers, and discovery responses:

First, as related to PG&E's administration and management of its UOG facilities, Cal Advocates recommended that the Commission order PG&E to:

- Hire an outside consultant, such as a metallurgist, to determine the cause of the premature failure of the exhaust valve at Humboldt Bay Generating Station, Unit 3 on August 9, 2024 and to prepare a root cause evaluation report.
- Provide, in the next ERRA Compliance filing following the completion of the metallurgy analysis, a copy of the metallurgical report of the failed Unit 3 exhaust valve and its follow-up actions.

Second, as related to review of balancing and memorandum accounts presented, Cal Advocates recommended that the Commission direct PG&E to:

- Adjust a credit associated with the Portfolio Allocation Balancing Account (PABA) tariff line-item 5.a.e for Cost-Allocation Methodology (CAM) replacement Resource Adequacy (RA) using the most recent RA Market Price Benchmark (MPB).
- Adjust the credit associated with PABA tariff line item 5.p for the gain on sale of the Burney Gardens property to account for errors in PG&E's initial assessment of the time the asset spent as Non-Utility Property (NUP) and a minor error in the stated purchase date of an asset.

C. CalCCA's Position

CalCCA's testimony, also served on September 15, 2025 following review of PG&E's Application, Prepared Testimony, workpapers, and discovery responses, asserted and recommended the following:

- As to PG&E's Retained Resource Adequacy (RA), CalCCA asserted that the Operational Constraints PG&E recognized as Retained RA in the PABA are inconsistent with the Operational Constraints approved by the Commission and specified in PG&E's BPP, and recommended that PG&E should recategorize RA capacity related to the approved Operational Constraints by reducing Unsold RA and increasing Retained RA.
- As to PG&E's testimony concerning its internal audit of Power Charge Indifference Adjustment (PCIA) vintaging of CCA customers, CalCCA recommended that PG&E should be required to file supplemental testimony detailing how its programming logic used for assigning customer vintages complies with the requirements of Decision (D.) 16-09-044 for all CCA customers and detailing the extent and impact of an issue identified for customers moving to a new address after opting out of and then back into CCA service.
- CalCCA noted that PG&E disclosed that it did not credit PABA for the value of the excess RA used to meet its incremental system reliability procurement targets in October 2024, but that through discovery PG&E confirmed that it made a correction

in April 2025 by crediting the PABA for the value of the October excess RA, plus the associated interest. CalCCA recommended that the Commission approve this correction to PG&E's record year accounting entries.

D. Issues Resolved Through PG&E's Rebuttal Testimony

PG&E's rebuttal testimony resolved Cal Advocates' recommendations relating to adjustments to the PABA. Namely, PG&E explained in its rebuttal testimony that (1) it made the adjustment Cal Advocates recommended associated with PABA tariff line-item 5.a.e for CAM replacement RA; and (2) it did not contest CalAdvocates' recommendation that PG&E adjust the credit associated with PABA tariff line item 5.p. for the gain on sale of the Burney Gardens property.

PG&E's rebuttal testimony also resolved CalCCA's recommendation concerning the credit to PABA associated with the excess RA used to meet its incremental system reliability procurement targets in October 2024. More specifically, PG&E agreed with CalCCA that the Commission should approve the correction PG&E made in April 2025 crediting the PABA for the value of the October excess RA, plus the associated interest.

The remainder of Cal Advocates' and CalCCAs' recommendations are addressed in the Settlement Agreement.

IV. SUMMARY OF THE SETTLEMENT AGREEMENT

The Settlement Agreement contains the following four substantive sections which set forth the Settling Parties resolution of the issues identified in Section III: (1) Humboldt Unit 3 Outage; (2) Balancing Accounts Reviewed; (3) Resource Adequacy; and (4) Customer Vintaging.

In Section 1, Cal Advocates agrees that PG&E recycled the exhaust value that prematurely failed on August 9, 2024; and as a result, Cal Advocates' recommendation to hire an outside consultant to perform a root cause evaluation is not possible. PG&E agrees that, in the event that Humboldt Unit 3 experiences a forced outage due to a repeat exhaust valve failure, PG&E will conduct an apparent cause or root cause analysis of the exhaust valve failure.

In Section 2, PG&E agrees to include the four balancing accounts Cal Advocates identified in its Protest for an accounting review—i.e., that the entries recorded comply with Commission decisions and rulings—in its ERRA Compliance applications on a going forward basis.

In Section 3, CalCCA agrees that it is reasonable for PG&E to calculate Retained RA in its 2024 RA Tracker using final capacity values (also referred to as "Derates") used for monthly compliance filings and that PG&E need not modify its Retained RA accounting for the record period.

In Section 4, CalCCA agrees that PG&E's supplemental testimony adequately addresses the recommendations set forth in CalCCA's testimony concerning PG&E's PCIA vintaging of CCA customers that opt-out of CCA service, relocate, and opt-in to CCA service, and agrees that PG&E's billing system logic assigns vintages to those customers in a manner that is consistent with the Commission's vintaging directives.

V. THE COMMISSION SHOULD ADOPT THE SETTLEMENT AS REASONABLE, CONSISTENT WITH THE LAW, AND IN THE PUBLIC INTEREST

Commission Rule 12.1(a) requires the Settling Parties to disclose "any separate agreements between the settling parties that relate to issues in the proposed settlement but are not disclosed in the settlement." There are no such separate agreements between the Settling Parties relating to the issues in the proposed Settlement Agreement here.

Commission Rule 12.1(d) sets forth the standard for adoption of settlements: "The Commission will not approve settlements, whether contested or uncontested, unless the settlement in reasonable in light of the whole record, consistent with law and in the public interest." The Commission approves settlement agreements based on whether the settlement agreement is just and reasonable as a whole, not based on its individual terms:

> In assessing settlements we consider individual settlement provisions but, in light of strong 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.[2]

Numerous Commission decisions "have endorsed settlements as an 'appropriate method of alternative ratemaking' and express a strong public policy favoring settlement of disputes if they are fair and reasonable in light of the whole record."[3] It is long-standing Commission policy to strongly favor settlement.[4] This policy supports many worthwhile goals, including not only reducing the expense of litigation and conserving scarce Commission resources, but also allowing parties to reduce the risk that litigation will produce unacceptable results.[5]

A. The Agreement is Reasonable In Light of the Record as a Whole

The Settling Parties are knowledgeable and experienced regarding the issues in this ERRA Compliance proceeding and represent distinct and affected interests: PG&E, which is responsible for procuring power to serve its customers; Cal Advocates, the Commission's independent ratepayer advocacy office; and CalCCA, representing the interests of CCA customers.

The Settling Parties reached agreement after the submission of lengthy testimony, including supplemental testimony, extensive discovery, careful analysis of issues, and settlement discussions. The Settlement Agreement reflects compromise based on the substantial record in this proceeding. For example, through testimony and discovery, Cal Advocates and PG&E agree that should Humboldt Unit 3 experience a further forced outage associated with an exhaust valve failure, an apparent or root cause analysis of the exhaust valve failure will be conducted. PG&E's testimony and data request responses also support CalCCA's agreement that PG&E need not modify its Retained RA accounting for the record period, and that its billing system logic correctly assigns vintages to customers who opt out of CCA service, opt-in, and relocate within the same CCA. The fact that PG&E, Cal Advocates, and CalCCA were able to find

[2] D.10-04-033, p. 9.

[3] *See e.g.,* D.05-10-041, p. 47; D.15-03-006, p. 6; and D. 15-04-006, p. 8.

[4] D.10-06-038, p. 38.

[5] D.14-12-040, p. 15.

common ground through record development and in areas where they originally differed indicates that the Settlement is reasonable in light of the whole record and reflects a reasonable balance of the various interests affected in this proceeding.

B. The Agreement is Consistent with Law and Prior Commission Decisions

The Settling Parties believe that the terms of the Settlement Agreement comply with all applicable statutes, including the prospective actions that PG&E will take in future ERRA Compliance proceedings. Applicable statutes include Public Utilities Code § 451, which requires that utility rates must be just and reasonable, and Public Utilities Code § 454, which prevents a change in public utility rates unless the Commission finds such an increase justified.[6] In this case, both Cal Advocates and CalCCA have extensively reviewed and audited the information PG&E presented in testimony and discovery responses to conclude that, subject to the terms of the Settlement Agreement, PG&E should be granted the relief requested in its Application.

Under the Settlement Agreement, PG&E agrees to undertake several prospective actions.[7] The Commission has used ERRA Compliance proceedings to address prospective issues, such as the actions addressed in this Settlement Agreement. For example, in D.09-12-002, the Commission directed that, prior to the next ERRA Compliance application, PG&E confer with Cal Advocates regarding PG&E's internal auditing of contract management activities.[8] In D.11- 07-039, the Commission adopted additional prospective requirements regarding internal auditing.[9] The Commission also approved prospective actions in the settlement of PG&E's 2011 ERRA Compliance application in D.14-01-011, and in PG&E's 2017 ERRA Compliance Application in D.18-02-015. Thus, including prospective actions in the Settlement Agreement is consistent with Commission precedent in previous ERRA Compliance proceedings.[10]

[6] *See* D.14-01-011, p. 14; D.15-05-015, p. 14.

[7] Settlement, Sections 1 and 2.

[8] D.09-12-002, OP 3.

[9] D.11-07-039, OP 2-3.

[10] D.14-01-011, p. 14 (prospective remedies consistent with the law).

C. The Agreement is in the Public Interest

The Settlement Agreement is in the public interest because it conserves Commission resources and the resources of the Settling Parties. But for the Settlement Agreement, PG&E, Cal Advocates, and CalCCA would submit post-hearing briefs regarding all disputed issues in this proceeding. This Settlement Agreement resolves all outstanding issues as between them in a manner the Settling Parties believe is just and reasonable. Furthermore, the Settlement Agreement is consistent with Commission decisions on settlements, which express the strong public policy favoring settlement of disputes if they are fair and reasonable in light of the whole record.[11]

VI. CONCLUSION

The Settling Parties request that the Commission adopt the Settlement Agreement without modification as reasonable in light of the whole record, consistent with the law and in the public interest. Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, PG&E represents that Cal Advocates and CalCCA authorized it to sign and tender this Joint Motion on their behalf.

Respectfully Submitted,

By: */s/ Ashley E. Merlo*
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Dated: May 22, 2026

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

[11] D.14-01-011, p. 13.

Application No. 25-02-013

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT

SETTLEMENT AGREEMENT BETWEEN PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), THE PUBLIC ADVOCATES OFFICE AT THE CALIFORNIA PUBLIC UTILITIES COMMISSION, AND THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, and Other Activities for the Record Period January 1 Through December 31, 2024. (U 39 E)	Application No. 25-02-013

SETTLEMENT AGREEMENT BETWEEN PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), THE PUBLIC ADVOCATES OFFICE AT THE CALIFORNIA PUBLIC UTILITIES COMMISSION, AND THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Pacific Gas and Electric Company (PG&E), the Public Advocates Office at the California Public Utilities Commission ("Cal Advocates"), and the California Community Choice Association (CalCCA) (collectively, the "Settling Parties") enter into this Settlement Agreement as a compromise of their respective litigation positions in order to resolve all issues raised by Cal Advocates and CalCCA in the above captioned proceeding before the California Public Utilities Commission (Commission). The Settling Parties have addressed all of the issues in this proceeding and have negotiated this Settlement which resolves all their disputes.

PROCEDURAL HISTORY

On February 28, 2025, PG&E filed its *Application for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement and Other Activities for the Record Period January 1 through December 31, 2024,* A.25-02-013 (Application). Concurrent with filing the Application, PG&E also served its Prepared Testimony and workpapers, as well as

responses to the Cal Advocates and CalCCA Master Data Requests (MDRs).

On April 4, 2025, Cal Advocates and CalCCA filed protests to PG&E's application. PG&E filed a reply to the protests on April 14, 2025.

A prehearing conference was held on April 18, 2025 to discuss the issues of law and fact and determine the need for hearing and a schedule for resolving the proceeding.

On May 2, 2025, Commissioner John Reynolds issued the Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo).

On September 15, 2025, Cal Advocates and CalCCA served their Testimony.

On October 24, 2025, PG&E served its Rebuttal Testimony.

On November 3, 2025, PG&E, CalCCA and Cal Advocates submitted a Joint Status Conference Statement, which (1) stated that CalCCA believed hearings may be necessary, and (2) jointly requested that discovery be re-opened and the deadline for completing settlement discussions be amended. In response, on November 10, 2025, the Administrative Law Judge (ALJ) issued a ruling re-opening discovery and amending the proceeding schedule for settlement discussions, status conference and evidentiary hearing.

In accordance with the November 10, 2025 ruling, CalCCA served and PG&E responded to data requests, and thereafter reported in an Updated Joint Status Conference Statement that CalCCA no longer believed hearings were necessary. On December 2, 2025, the ALJ held a virtual status conference, at which the ALJ modified the proceeding schedule to remove evidentiary hearings.

On December 15, 2025, the parties filed a Joint Motion to Enter Evidence into the Evidentiary Record, accompanied by PG&E's Motion to Seal the Evidentiary Record. Both motions were granted on December 23, 2025.

On December 22, 2025, the assigned ALJ issued a ruling directing PG&E to prepare supplemental testimony regarding vintaging of a specific group of community choice aggregator customers. The ruling also amended the proceeding schedule to allow time for the supplemental testimony.

On January 6, 2026, PG&E sent a procedural email to the ALJ. In that email, PG&E stated that (1) it would likely need more time to prepare the testimony directed in the ALJ's December 22 ruling, and (2) CalCCA would like more time to respond to the additional testimony.

On January 26, 2026, the assigned ALJ held a status conference to discuss PG&E's need for an extension. Following the status conference, the ALJ issued a ruling on February 2, 2026. In that ruling, the ALJ directed PG&E to submit supplemental testimony on March 11, 2026, and set a deadline of April 10, 2026 for CalCCA to submit reply testimony.

Subsequently, PG&E served its supplemental testimony on the March 11, 2026 deadline. In a procedural email sent on April 10, 2026, CalCCA notified the parties that it did not intend to submit reply testimony.

On April 14, 2026, PG&E, CalCCA, and CalAdvocates filed a Joint Motion to Admit Supplemental Testimony and Workpapers into the Evidentiary Record, in accordance with the ALJ's February 2, 2026 ruling. The ALJ granted that motion on May 12, 2026.

Cal Advocates and CalCCA have reviewed PG&E's Application, testimony, supplemental testimony, workpapers, and discovery responses, and do not object to the relief requested in PG&E's Application, subject to the terms of this Settlement Agreement.

SETTLEMENT AGREEMENT TERMS AND CONDITIONS

The Settling Parties agree to the following terms and conditions:

1. Humboldt Unit 3 Outage

1.1. PG&E recycled the exhaust value that prematurely failed on August 9, 2024; as a result, Cal Advocates' recommendation to hire an outside consultant to perform a root cause evaluation is not possible.

1.2. PG&E agrees that, in the event that Humboldt Unit 3 experiences a forced outage due to a repeat exhaust valve failure, PG&E will hire an outside consultant to conduct a root

cause analysis of the exhaust valve failure. The findings of the root cause analysis will be provided to Cal Advocates.

2. Balancing Accounts Reviewed

2.1. PG&E agrees to include the following balancing accounts for review—i.e., to ensure that the entries recorded comply with Commission decisions and rulings—in its ERRA Compliance applications on a going-forward basis: (i) New System Generation Balancing Account; (ii) Modified Transition Cost Balancing Account; (iii) Tree Mortality Non-Bypassable Charge Balancing Account; and (iv) BioMat Non-Bypassable Charge Balancing Account.

2.2. The accounts listed in Section 2.1 are in addition to the following accounts that are already included in PG&E's ERRA Compliance filings:

- Energy Resource Recovery Account (ERRA)
    - Recorded 2024 Year-End Balance: Credit of $243,768,949
- Portfolio Allocation Balancing Account (PABA)
    - Recorded 2024 Year-End Balance: $914,051,803
- Green Tariff Shared Renewables Memorandum Account (GTSRMA)
    - Recorded 2024 Cost: $622,641
- Green Tariff Shared Renewables Balancing Account (GTSRBA)
    - Recorded 2024 Year-End Balance: $15,720,796
- Renewables Portfolio Standard Cost Memorandum Account (RPSCMA)
    - Recorded 2024 Cost: $0
- Disadvantaged Communities – Single Family Solar Affordable Homes Balancing Account (DACSASHBA)
    - Recorded 2024 Cost: $5,114,495
- Disadvantaged Communities – Green Tariff Balancing Account (DACGTBA)
    - Recorded 2024 Cost: $10,127,171

- Community Solar Green Tariff Balancing Account (CSGTBA)
    - Recorded 2024 Cost: $123,136
- Centralized Local Procurement Sub-Account (CLPSA)
    - Recorded 2024 Administrative Costs: $1,858,931

3. Resource Adequacy (RA)

3.1. CalCCA agrees it is reasonable for PG&E to calculate Retained RA in its 2024 RA Tracker using final capacity values (also referred to as "Derates") used for monthly RA compliance filings.

3.2. CalCCA agrees that PG&E need not modify its Retained RA accounting for the 2024 record period.

4. Customer Vintaging

4.1. CalCCA agrees that PG&E's supplemental testimony adequately addresses the recommendations set forth in CalCCA's testimony concerning the vintaging of community choice aggregator ("CCA") customers who affirmatively opt out of CCA service and later opt-in and relocate within the incumbent CCA territory. Out of 156 CCA customers who satisfied these criteria in the targeted queries PG&E conducted, only one customer had been improperly vintaged. PG&E identified the root of this improper vintaging to be human error rather than system logic.

4.2. As described in PG&E's supplemental testimony, with respect to customers who opt out of CCA service, subsequently opt-in and relocate within the same CCA territory, PG&E's billing system logic assigns vintages to those customers in a manner that is consistent with the Commission's vintaging directives. Specifically, PG&E's system assigns those customers a vintage based on the date they opted in to CCA service, and if the customer moves within the same CCA service area, they retain their vintage based on the date of opt-in. If a CCA customer moves within PG&E's service area to a CCA service area with a different vintage or a different phase-in date, that customer is assigned the default vintage for that location..

5. GENERAL PROVISIONS

5.1. In accordance with Rule 12.5, the Settling Parties intend that Commission adoption of this Settlement Agreement will be binding on the Settling Parties, including their legal successors, assigns, partners, members, agents, parent or subsidiary companies, affiliates, officers, directors, and/or employees. Unless the Commission expressly provides otherwise, and except as otherwise expressly provided herein, such adoption does not constitute approval or precedent for any principle or issue in this or any future proceeding.

5.2. The Settling Parties agree that nothing contained in this Settlement Agreement is to be construed as an admission of liability, fault, or improper action by any Party.

5.3. The Settling Parties agree that this Settlement Agreement is subject to approval by the Commission. As soon as practicable after the Settling Parties have signed this Settlement Agreement, the Settling Parties shall jointly file a motion for Commission approval and adoption of the Settlement Agreement. The Settling Parties will furnish such additional information, documents, and/or testimony as the ALJ or the Commission may require in granting the motion adopting this Settlement Agreement.

5.4. The Settling Parties agree to support the Settlement Agreement and use their best efforts to secure Commission approval of the Settlement Agreement in its entirety without modification.

5.5. The Settling Parties agree to recommend that the Commission approve and adopt this Settlement Agreement in its entirety without change.

5.6. The Settling Parties agree that, if the Commission fails to adopt this Settlement Agreement in its entirety and without modification, the Settling Parties shall convene a Settlement Agreement Conference within fifteen (15) days thereof to discuss whether they can resolve the issues raised by the Commission's actions. If the Settling Parties cannot mutually agree to resolve the issues raised by the Commission's actions, the Settlement Agreement shall be rescinded, and the Settling Parties shall be released from

their obligation to support the Settlement Agreement. Thereafter, the Settling Parties may pursue any action they deem appropriate but agree to cooperate in establishing a procedural schedule.

5.7. The Settling Parties agree to actively and mutually defend the Settlement Agreement if its approval and adoption is opposed by any other party.

5.8. This Settlement Agreement constitutes the Settling Parties' entire Settlement Agreement, which cannot be amended or modified without the express written and signed consent of each of the Settling Parties hereto.

6. MISCELLANEOUS PROVISIONS

6.1. The Settling Parties agree that no signatory to the Settlement Agreement or any employee thereof assumes any personal liability as a result of the Settlement Agreement.

6.2. If any Party fails to perform its respective obligations under the Settlement Agreement, any other Party may come before the Commission to pursue a remedy including enforcement.

6.3. The provisions of this Settlement Agreement are not severable. If the Commission, or any competent court of jurisdiction, overrules or modifies any material provision of the Settlement Agreement, the Settlement Agreement will be rescinded as of the date such ruling or modification becomes final if the Settling Parties fail to reach agreement pursuant to the Settlement Agreement Conference process set forth in Section 5.6 above.

6.4. The Settling Parties acknowledge and stipulate that they are agreeing to this Settlement Agreement freely, voluntarily, and without any fraud, duress, or undue influence by any other party. Each party states that it has read and fully understands its rights, privileges, and duties under the Settlement Agreement, including each Party's right to discuss the Settlement Agreement with its legal counsel and has exercised those rights, privileges, and duties to the extent deemed necessary.

6.5. In executing this Settlement Agreement, each Party declares and mutually agrees that the terms and conditions are reasonable, consistent with law, and in the public interest.

6.6. No Party has relied, or presently relies, upon any statement, promise, or representation by any other Party, whether oral or written, except as specifically set forth in this Settlement Agreement. Each Party expressly assumes the risk of any mistake of law or fact made by such Party or its authorized representative.

6.7. This Settlement Agreement may be executed in separate counterparts by the different Settling Parties hereto with the same effect as if all Settling Parties had signed one and the same document. All such counterparts shall be deemed to be an original and shall together constitute one and the same Settlement Agreement.

6.8. This Settlement Agreement shall become effective and binding on the Settling Parties as of the date it is approved by the Commission in a final and non-appealable decision.

6.9. This Settlement Agreement shall be governed by the laws of the State of California as to all matters, including but not limited to, matters of validity, construction, effect, performance, and remedies.

/ / /

The Settling Parties mutually believe that, based on the terms and conditions stated above, this Settlement Agreement is reasonable in light of the whole record, consistent with the law, and in the public interest. The Settling Parties' authorized representatives have duly executed this Settlement Agreement on behalf of the parties they represent.

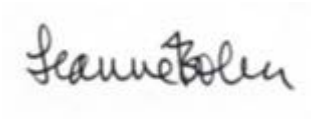
PACIFIC GAS AND ELECTRIC COMPANY

/s/ Shilpa Ramaiya

SHILPA RAMAIYA
Vice President, Regulatory Proceedings & Rates

Date: May 19, 2026

CALIFORNIA COMMUNITY CHOICE ASSOCIATION



/s/

LEANNE BOBER
Director of Regulatory Affairs and Deputy General Counsel
California Community Choice Association

Date: May 20, 2026

PUBLIC ADVOCATES OFFICE AT THE CALIFORNIA PUBLIC UTILITIES COMMISSION

/s/ Nathaniel W. Skinner

Deputy Director – Energy & Admin, Public Advocates Office

Date: May 21, 2026

DOCKETED	
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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *2025 Integrated Energy Policy Report (2025 IEPR)*	DOCKET NO. 25-IEPR-01 DRAFT 2025 INTEGRATED ENERGY POLICY REPORT

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE DRAFT 2025 INTEGRATED ENERGY POLICY REPORT

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May 15, 2026

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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *2025 Integrated Energy Policy Report (2025 IEPR)*	DOCKET NO. 25-IEPR-01 DRAFT 2025 INTEGRATED ENERGY POLICY REPORT

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE DRAFT 2025 INTEGRATED ENERGY POLICY REPORT

The California Community Choice Association[1] (CalCCA) submits these comments pursuant to the *Notice of Availability and Request for Comments on the Draft 2025 Integrated Energy Policy Report*[2] (Notice), seeking public comment on the *Draft 2025 Integrated Energy Policy Report*[3] (Draft Report), dated April 2026.

I. INTRODUCTION

Development of the Integrated Energy Policy Report (IEPR) by California Energy Commission (Commission) staff requires synthesizing an enormous amount of data and evaluating the most pressing energy needs and issues with input from a wide variety of stakeholders. Current fluctuating policy, technological, and market forces further complicate this difficult task. CalCCA appreciates the work of Commission staff in developing the Draft Report.

[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, Peninsula Clean Energy, 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, and Valley Clean Energy.

[2] *Notice of Availability and Request for Comments on the Draft 2025 Integrated Energy Policy Report*, 25-IEPR-01 (Apr. 23, 2026).

[3] *Draft 2025 Integrated Energy Policy Report*, 25-IEPR-01 (Apr. 2026).

An increasingly important component of the IEPR is the California Electricity Demand Forecast (Demand Forecast), which serves as an input into many of the state's key energy planning and reliability tools, such as the California Public Utilities Commission (CPUC) Resource Adequacy (RA) and Integrated Resource Planning (IRP) programs, the California Independent System Operator's (CAISO) Transmission Planning Process (TPP), and the investor-owned utilities' (IOU) distribution planning processes. Load forecasting is becoming increasingly uncertain and complex with the emergence of new large loads, such as data centers, electrification, and other drivers of load growth. In addition, the speed at which customers seek energization results in IOUs including customers in the early stages of the interconnection process (*i.e.,* Known Loads) in their load forecasts, when those customers have not previously been included. The Commission has taken a measured approach in the IEPR by managing the uncertainty of data center loads using scenarios with different confidence levels. The Commission also plans for the uncertainty of Known Loads by including them in the scenario for distribution and transmission planning (Local Reliability Scenario), but excluding them from the scenario used for IRP and RA planning (Planning Scenario).

CalCCA supports the approaches taken by the Commission on both data centers and Known Loads. CalCCA also appreciates the Commission's commitment to advance its forecasting capabilities in light of the unprecedented uncertainty load forecasters across the nation face with the introduction of new large loads. To further improve these processes, CalCCA recommends that in future IEPR processes, the Commission should: (1) solicit information on new loads from all informed stakeholders including CCAs to inform the likelihood and timing of large loads before including them in the forecast; (2) coordinate with the CPUC to adopt a formal process for allocating RA obligations for data center load based on

actual interconnection information and milestones; (3) reassess the Demand Forecasts' planning areas and forecast zones to ensure they accurately reflect the characteristics of the communities they include; and (4) continue to exclude Known Loads from the Planning Scenario.

The IEPR also evaluates several key issues impacting California's ability to supply affordable, reliable, and clean electricity. To advance these issues going forward, the Commission should continue to explore necessary improvements to the development of the planning portfolios used in the TPP. Mapping resources in commercially viable locations will help provide for sufficient deliverability in the right locations to support investments in new generation capacity. The Commission should also take the time necessary to holistically review load shift strategies to ensure they provide sufficient flexibility to adequately account for market incentives, customer behavior, grid needs, and equitable participation across load shift service providers.

In summary, in future IEPR processes, the Commission should:

- Solicit information on new loads from all informed stakeholders including CCAs to inform the likelihood and timing of large loads, including data centers, before including them in the Demand Forecast;
- Coordinate with the CPUC to adopt a formal process for allocating RA obligations for data center load based on actual interconnection information and milestones;
- Continue to review Demand Forecast planning areas and forecast zones to ensure they accurately reflect the load characteristics of the communities they include;
- To the extent the Commission considers including Known Loads as defined in the 2025 IEPR process in the Demand Forecast, continue to exclude them from the Planning Scenario;
- Continue to explore necessary improvements to ensure sufficient deliverability for resources in the CAISO Balancing Authority Area (BAA) needed to provide system reliability; and
- Holistically review load shift strategies to ensure they provide sufficient flexibility to adequately account for market incentives, customer behavior, grid needs, and equitable participation across load shift service providers.

II. THE COMMISSION SHOULD CONTINUE REFINING ITS FORECASTING TOOLS IN FUTURE IEPR CYCLES IN LIGHT OF UNPRECEDENTED UNCERTAINTY ASSOCIATED WITH THE INTRODUCTION OF NEW LARGE LOADS

Load forecasting has become increasingly uncertain and complex with the emergence of new large loads, such as data centers, along with electrification and other drivers of load growth. CalCCA supports the Commission "continu[ing] to advance its forecasting capabilities as part of its focus on providing science-based planning tools needed in the transition to a clean energy future."[4] In doing so, in future IEPR cycles, the Commission should: (1) solicit information from all informed stakeholders, including CCAs, to inform the likelihood and timing of large loads; (2) coordinate with the CPUC to adopt a formal process for including data center loads in the RA forecast using interconnection milestones; (3) review the Demand Forecast's forecast zones and planning areas to ensure they accurately reflect the regions' expected load; and (4) continue to exclude Known Loads from the Planning Scenario, as described herein.

A. Information From All Informed Parties, Including CCAs, Should Be Solicited to Inform the Likelihood and Timing of Large Loads Before Including Them in the Forecast

CalCCA and its members appreciate the opportunities within the IEPR process to provide feedback to Commission staff. CalCCA also appreciates the openness of Commission staff to evaluate incorporating this feedback in its development of the Demand Forecast. The Commission should capitalize on the knowledge and expertise of CCAs, along with other stakeholders, to verify the information received from IOUs regarding future loads, including data centers. The IEPR's data center forecast is developed "using information from utilities, including project status and requested capacity," to create "three scenarios for data center growth that

[4] Draft Report, at 7.

reflect a range of possible outcomes."[5] In future IEPR processes, in addition to obtaining information from the utilities, the Commission should solicit information from all informed parties, including CCAs, to inform the likelihood and timing of large loads before including them in the Demand Forecast.

CCAs serve local communities and are well-positioned to evaluate new load growth given their unique access to information, either from large load customers or their local permitting agencies. Cities and counties have data on land use and building permits that can help inform the load forecast. Each CCA's association with cities and counties will give it unique access and insight into the status of development of the new facilities, including when they are expected to be operational. This insight is valuable, as information received from the customer by the IOUs is often insufficient to inform the IEPR Demand Forecast, as described in the CalCCA 2026 Draft Scoping Order Comments.[6] CalCCA urges the Commission to make ample use of the information community-based LSEs such as CCAs can provide.

To ensure all informed parties can provide insight into and verification of proposed forecasts, the Commission should strive to make as much data public as possible before it is relied upon in the IEPR Demand Forecast. Historically, it has not been possible for CCAs and data center customers to validate the information provided by the IOUs before it is used in the

[5] Draft Report, at 8.

[6] *See California Community Choice Association's Comments on the Draft Scoping Order for the 2026 Integrated Energy Policy Report Update*, Docket No. 26-IEPR-01 (Mar. 25, 2026) (CalCCA 2026 Draft Scoping Order Comments), at 3-5. For example, IOU energization dates alone are not a sufficient estimate as to when a project will come online, especially in the near term. Data centers with a 2027 energization date that have not started the permitting process would likely be delayed. In addition, energization requests to an IOU do not account for project feasibility. For example, in San Jose, assumed energization timing may be optimistic for data centers in the downtown area, which has additional permitting considerations. Additionally, as CCAs are community-based, CCA staff and local partners have the unique ability to personally observe the progress of any large load construction or build out. What is observed – and verified by local permitting status – may not align with IOU information. Lastly, actual usage of requested capacity may also differ by area, and a single assumption may not adequately reflect these differences.

IEPR because it is submitted confidentially. CCAs have observed that once a CCA receives the data, it is often duplicative and/or contains errors.[7] The CEC should therefore either require the data be shared with CCAs or request information from both IOUs and CCAs and validate the information for consistency. Given reliability and cost implications of forecasting new loads, ensuring all informed stakeholders can review the data before it is used in the IEPR Demand Forecast is necessary to ensure the forecast is as accurate as possible.

B. The Commission Should Coordinate with the CPUC to Adopt a Formal Process for Allocating RA Obligations for Data Center Load Based on Actual Interconnection Information and Milestones

A formal process for allocating data center load driven RA obligations based on interconnection milestones is necessary to ensure RA obligations are allocated fairly and not based on speculative loads. Increased transparency and data sharing across the Commission, CCAs, IOUs, and data center customers is imperative to informing the likelihood and timing of data center loads, as described in Section II.A, above. This data sharing may be sufficient for longer term planning (*e.g.,* transmission planning) for which the specific generation provider need not be known. When it comes to allocating LSE obligations associated with data center load for generation procurement purposes, a formal process is necessary for allocating data center load based upon predefined milestones.

For this reason, CalCCA filed a proposal in the CPUC's RA proceeding, R.25-10-003, for the unique treatment of data center loads in the RA allocation process.[8] The IEPR Demand Forecast is a key input into the establishment of RA obligations that load-serving entities (LSE)

[7] For example, upon notification that five of eight interconnection applications in a CCA service area were expected to be data centers, one CCA's investigation found that of the five data center applications, three were not in their service area and two were scaled down to smaller, non-data center loads.

[8] *See California Community Choice Association's Track 1 Proposals*, Rulemaking (R.) 25-10-003 (Jan. 23, 2026) (CalCCA Track 1 Proposal), at 3-7; and *California Community Choice Association's Comments on Track 1 Proposals*, R.25-10-003 (Mar. 6, 2026), at 3-8.

must meet as part of the CPUC's RA program.[9] CalCCA's proposal is intended to maintain the collaborative process between the Commission and CPUC, in which the Commission continues to forecast peak demand, and data centers' portion of the forecast, and make LSE specific adjustments. For the purposes of allocating RA requirements, the proposal would establish a new process for allocating new data center loads separate from the existing process used to allocate all other loads. CalCCA recommends that this new process include the following components: (1) considering data center load separately from other forecasted load for RA purposes, using actual rather than forecasted load to determine RA obligations; and (2) allocating an RA obligation to an LSE serving a data center when certain milestones are met, such as having chosen a LSE generation provider, having an executed interconnection agreement, and having begun construction.

Establishment of a formal process is necessary to protect existing customers from absorbing costs associated with data center load by determining when data center load service is reasonably certain, identifying the LSE that will serve the data center load, and allocating RA obligations accordingly. Accounting for data center load on an individual basis for RA allocation purposes can mitigate the risk of load forecast inaccuracy. By allocating data center load to the correct LSE with a high degree of certainty, as opposed to the "peanut butter" approach, this proposal has the added benefit of reducing potential cost-shifts between LSEs that experience substantial load growth associated with particular data centers (and are thus able to recover capacity costs from those data centers via rates) and other LSEs that are not.[10]

[9] Draft Report, at 12 ("The [Commission], CPUC, and California ISO agree to use specific combinations of this forecast set for planning and procurement, which will be documented in the final *IEPR*. The planning forecast is used for [RA] and [IRP].").

[10] This proposal also avoids the need to assume which LSE will serve the data center load for the purposes of RA allocations. CCAs are default providers, and they are willing and able to serve data center

C. Electricity Demand Forecast Zones Should be Reviewed to Ensure They Accurately Reflect Regions' Expected Load Changes in Light of the Concentration of Large Loads

The Commission should continue to review the planning areas and forecast zones as part of the 2026 IEPR process to ensure that they accurately reflect regions' expected load changes. The Demand Forecast includes annual electricity consumption and sales forecasts by customer sector for eight planning areas and 20 forecast zones.[11] These planning areas and forecast zones impact LSEs' load allocations used to establish RA requirements and other reliability procurement obligations. The Commission states that during 2025, the Commission sought to "improv[e] the capability to easily change (increase or decrease) … forecast zones… included in the forecast" to be used in the 2026 IEPR update.[12]

CalCCA supports this effort and encourages additional review of how forecast zones and planning areas are mapped to ensure they proportionally reflect both cities' and counties' projected load changes. This review is necessary considering the influx of large loads, which could have disproportionate impacts on communities where they are located, especially if large loads are concentrated in specific areas within planning areas and forecast zones. In addition, certain forecast zones may be incorporated into an area with overall high load growth, even though a portion of that zone has no load growth or even has decreasing load. The Commission should therefore conduct additional review of forecast zones and planning areas and consider

loads in their territories. In fact, some already serve these loads. Their intent to serve data center load does not mean that all customers will choose the CCA as their generation provider. If there is a delay in implementing CalCCA's proposed approach, the 2026 IEPR Update should allow for further discussion around how to develop opt-out assumptions for large loads. For example, the Commission has provided data center load by CCA in gigawatt-hour (GWh), but not by number of customers. Because opt-outs occur based upon number of customers, access to this data by number of customers would be helpful in informing how to best develop opt out assumptions.

[11] *See* GIS map of planning areas and forecast zones, https://cecgis-caenergy.opendata.arcgis.com/datasets/CAEnergy::california-electricity-demand-forecast-zones/explore?location=37.208945%2C-118.876986%2C6.

[12] Draft Report, at 81.

whether further modifications are necessary to accurately reflect projected load changes in specific locations.

D. To the Extent the Commission Considers Including Known Loads in the 2026 IEPR Update, It Should Continue to Exclude Them from the Planning Scenario

The Commission identified Known Loads as a significant source of uncertainty in the draft Report and commits to additional analysis to understand trends in known loads data as part of the 2026 IEPR update.[13] To the extent the 2026 IEPR Update considers Known Loads as defined in the IEPR, the Commission should continue to exclude them from the Planning Forecast, given: (1) the uncertainty of Known Loads; and (2) the Planning Forecast's intended purpose.[14] Known Loads data is collected from each IOU, and reflects customer information regarding project capacity sector, energization data, and load profiles. Significant questions remain regarding the accuracy of the Known Loads information, as well as its appropriateness for inclusion in the Planning Forecast.

Known Loads, as defined during the 2025 IEPR process, include projects that require upstream capacity upgrades that could take several years to complete before a customer load can be energized. Other project timelines are dependent on customers, permitting agencies, or contractors to complete portions of the work. Other factors, such as supply chain delays and environmental reviews, could further delay energization times. It is also still unclear whether the Known Loads' methodology has been properly adjusted to reflect the coincident peak or to resolve issues of duplication and other errors revealed during the 2025 IEPR process.

The primary use case of Known Loads data is to ensure sufficient distribution and local capacity to maintain reliability. Known Loads therefore may be appropriate to include in the

[13] Draft Report, at 7-8.
[14] CalCCA 2026 Draft Scoping Order Comments, at 7.

Local Reliability forecast. However, coincidence factors for this local use case are expected to differ from the coincidence factor for a use case based on system-wide demand. The Planning Forecast is applied to use cases driven by system-wide demand, as in RA requirements, bulk transmission planning, or IRP. As such, it is inappropriate to assume that the contribution of Known Loads to local reliability requirements would be the same as the contribution of Known Loads to the Planning Forecast used for system-wide requirements. The Commission should therefore conduct additional data collection and analysis on Known Loads to inform coincidence factors that differ between using Known Loads for local reliability versus system planning. These coincidence factors could then be used to evaluate the appropriateness of the Commission's inclusion of Known Loads in each Demand Forecast produced in the IEPR. Until this analysis is complete, to the extent the Commission considers including Known Loads, as defined in the IEPR, in the 2026 IEPR Update, it should continue to exclude them from the Planning Scenario.

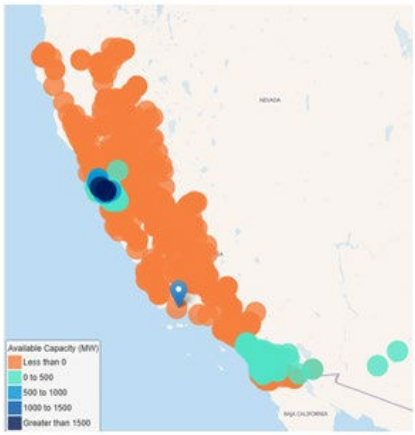
III. THE COMMISSION SHOULD COORDINATE WITH THE CPUC AND CAISO TO ENSURE SUFFICIENT DELIVERABILITY FOR NEW GENERATION

As stated in the IEPR, "California must sustain an unprecedented expansion of clean electricity generation and storage, along with continued electrification of the transportation, residential, and industrial sectors, while controlling costs."[15] The ability for internal and external resources to deliver to CAISO load is a key factor in achieving this objective. The RA and IRP programs generally require resources to be fully deliverable to count towards compliance obligations. Total deliverability on the CAISO system is scarce, as shown below, below, and must be allocated across resources internal and external to the CAISO BAA. In addition, "delays in network upgrades negatively affect the state's ability to meet its resource adequacy needs by

[15] Draft Report, at 86.

hindering the ability of projects to obtain deliverability status, in addition to increasing curtailment."[16]

The Commission, CPUC, and CAISO should ensure their processes enable the interconnection of sufficient deliverable generation to support reliability and policy objectives. The memorandum of understanding (MOU) between these entities ensures resource and transmission planning processes are coordinated to "driv[e] the future infrastructure of the grid, so that the [Commission's] load forecasts and the CPUC's forward-looking resource portfolios remain the key assumptions for [the CAISO's] assessment of transmission needs."[17] The CAISO's recent enhancements to its interconnection process "identifies and prioritizes transmission zones with available or planned capacity, then limits the capacity studied in each zone to 150 percent of available transmission capacity for each zone."[18] CalCCA appreciates the CAISO's efforts to increase the efficiency of and identify the most viable projects in the interconnection queue. However, available transmission capacity is scarce, as shown in Figure 1 below.



Available Capacity (MW)	# of Substations
Less than 0	578
0-500	160
500-1,000	6
1,000-1,500	0
1,500+	3

Figure 1: Cluster Phase 1 Scenario Heatmap[19]

16 Draft Report, at 102.
17 *Id.*, at 95.
18 *Id.*, at 98.
19 https://www.caiso.com/poi-heatmap/.

Without new transmission capacity associated with policy approvals in TPP, the amount of Cluster 16 projects that can enter the interconnection queue may be severely limited when new deliverable generation is needed. The CPUC recently ordered procurement of 6,000 megawatts (MW) of deliverable net qualifying capacity to serve reliability needs between 2029-2032.[20] In addition, RA capacity has been scarce for the last few years, triggering high prices and penalties for non-compliance.[21] While recent build has helped, load growth and other factors may require more RA to be procured. Through the MOU, the Commission, CPUC, and CAISO each play a role ensuring the resource planning portfolios result in sufficient transmission capacity to interconnect new resources in the right quantities and locations to support reliability and policy objectives. These entities should work together to ensure sufficient deliverability to support these objectives.

IV. LOAD SHIFT STRATEGIES SHOULD BE HOLISTICALLY REVIEWED TO ENSURE THEY ADEQUATELY CONSIDER MARKET INCENTIVES, CUSTOMER AND GRID NEEDS, AND EQUITABLE PARTICIPATION

The Commission should carefully and holistically review load shift strategies to ensure they provide sufficient flexibility to adequately account for market incentives, customer behavior, grid needs, and equitable participation across load shift service providers. While the Commission has the difficult task of facilitating seven gigawatts (GW) of load shift by 2030, the complexity of demand management systems and how they interact with customers and markets requires methodical review. It may be tempting to rush to deploy more load shifting technologies into homes and businesses, but a holistic review that allows sufficient time to process and plan will lead

[20] D.26-02-057, *Decision Requiring 2029-2032 Electric Resource Procurement and Transmitting Portfolios for 2026-2027 Transmission Planning Process*, R.25-06-019 (Mar. 5, 2026).

[21] CalCCA analysis of Federal Energy Regulatory Commission (FERC) Electric Quarterly Report (EQR) data demonstrates that prices for RA reached over $100 per kilowatt (kW) -month in 2024. CalCCA observed three transactions (totaling 92 MW) at prices of $100-101/kW-month for sale of capacity to California LSEs, delivered in 2024. The source of the data is CalCCA analysis of EQRs downloaded from https://eqrreportviewer.ferc.gov/.

to a more sustainable and impactful system of load shifting strategies. The Draft Report acknowledges this, and identifies the remaining challenges for reaching seven GW of load shift.[22]

The Commission's Load Management Standards (LMS) should also be interpreted and applied in a flexible manner to support innovation across LSEs and distributed energy resources (DER) providers in achieving load shift. At its April 8, 2026, Business Meeting, the Commission voted to begin the pre-rulemaking process to re-open the LMS regulations to improve implementation and expand participation.[23] When preparing for potential modifications to the LMS regulations, the Commission should focus on ensuring LMS regulations are interpreted and applied in a flexible and beneficial manner.

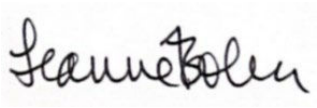
Flexibility in achieving state goals has underpinned California's leadership in climate action and should not stop with LMS. While marginal cost-based rates can serve a valuable role in promoting load flexibility, so too can programs that incentivize load shifting, particularly for residential customers. More evaluation and review are needed to parse out optimal approaches to load shifting across electric rate classes. The IEPR acknowledges this in discussing issues with customer incentives, consumer experiences, and equity and affordability considerations.[24] Different sectors may need different approaches to load flexibility to maximize participation and to fairly compensate participants for the value of that load flexibility.

22 Draft Report, at 131 (describing the work needed to achieve seven GW of load shift).
23 26-BUSMTG-01, *April 8, 2026, Business Meeting Agenda*, Item 6, at 5.
24 IEPR, at 129.

V. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments herein.

Respectfully submitted,



Leanne Bober,
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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

May 15, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Energization Timelines.	R.24-01-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ASSIGNED COMMISSIONER'S AMENDED PHASE 2 SCOPING MEMO AND RULING

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May 28, 2026

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SUMMARY OF RECOMMENDATIONS[1]

In response to party Opening Comments, CalCCA urges the Commission to:

- Reject IOU efforts to delay enforcement or penalty mechanisms associated with the energization benchmarks, and instead confirm energization targets established in Phase 1 are not aspirational and will continue to be improved through enforcement;
- Adopt enforcement mechanisms and citation structures similar to those proposed by CalCCA and supported by SCE and Cal Advocates;
- Adopt Cal Advocates' recommendations to ensure SB 254 auditor independence and effectiveness; and
- Adopt SCTCA's and SPUR's recommendations for enhanced transparency and public-facing monitoring and require elimination of unnecessary redactions in energization reporting.

[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 Establish Energization Timelines.	R.24-01-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ASSIGNED COMMISSIONER'S AMENDED PHASE 2 SCOPING MEMO AND RULING

California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to the *Assigned Commissioner's Amended Phase 2 Scoping Memo and Ruling*[3] (Ruling), dated March 19, 2026, and *Email Ruling Granting Party Status and Extending Comment Deadline*,[4] dated April 10, 2026.

I. INTRODUCTION

Opening Comments[4] confirm broad consensus that energization delays continue to impede California's critical policy priorities, including housing development, transportation electrification, building decarbonization, local government climate initiatives, and broad clean energy goals. Numerous parties explain that energization delays are not merely administrative inconveniences, but rather barriers to the implementation of various state policies:

[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, Peninsula Clean Energy, 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, and Valley Clean Energy.

[3] *Assigned Commissioner's Amended Phase 2 Scoping Memo and Ruling*, Rulemaking (R.) 24-01-018 (Mar. 19, 2026).

[4] Opening Comments refer to party opening comments submitted in this proceeding on or about April 30, 2026.

- **Housing –**The Housing Action Coalition (HAC) explains that "timely and predictable energization is a real-world financing and delivery issue" because housing projects rely on "defined timelines tied to tax credit equity, construction loans, rate locks, multi-agency leasing processes, and regulatory deadlines."[5]

- **Climate –** Local Government Sustainable Energy Coalition (LGSEC) states that local governments "depend on rapid utility connections to implement Climate Action Plans (CAPs) and achieve state decarbonization goals."[6]

- **Electrification –** California Solar & Storage Association (CALSSA) emphasizes that delays in main panel upgrades directly undermine electrification because "[e]very customer who shies away from an electrification option at the time of vehicle or appliance replacement is, in practical terms, locked into a fossil fuel appliance or vehicle for years or decades.[7]

- **Fleet Electrification –** CALSTART, Inc. (CALSTART) explains that energization timelines exceeding 24 months "remain among the largest barriers to achieving state climate" goals for fleet electrification.[8]

These comments reinforce CalCCA's opening comments: the Commission established energization targets in Phase 1 to accelerate customer energization and support California's decarbonization goals. The Commission did not create optional aspirational benchmarks that utilities may indefinitely defer achieving. In their Opening Comments, the investor-owned utilities (IOU) continue to push back on any enforcement or penalty mechanisms being attached to the benchmarks.

In response to party Opening Comments, CalCCA urges the Commission to:

- Reject IOU efforts to delay enforcement or penalty mechanisms associated with the energization benchmarks, and instead confirm energization targets established in Phase 1 are not aspirational and will continue to be improved through enforcement;

- Adopt enforcement mechanisms and citation structures similar to those proposed by CalCCA and supported by Southern California Edison Company (SCE) and The Public Advocates Office at the California Public Utilities Commission (Cal Advocates);

5 HAC Opening Comments, at 2.
6 LGSEC Opening Comments, at 2.
7 CALSSA Opening Comments, at 1.
8 CALSTART Opening Comments, at 5.

- Adopt Cal Advocates' recommendations to ensure SB 254 auditor independence and effectiveness; and

- Adopt SCTCA's and SPUR's recommendations for enhanced transparency and public-facing monitoring and require elimination of unnecessary redactions in energization reporting.

II. IOU CHARACTERIZATION OF ENERGIZATION TARGETS AS ASPIRATIONAL SHOULD BE REJECTED

Despite the Commission's clear direction in Decision 24-09-020,[9] the IOUs appear to believe the energization targets from Phase 1 are aspirational goals rather than enforceable performance standards. These characterizations should be rejected. Most directly, SCE states:

> In other words, the energization targets are just that – targets to strive for and distinct from strict deadlines or compliance requirements.[10]

Similarly, Pacific Gas and Electric Company (PG&E) argues:

> At this stage, PG&E believes it is premature to draw conclusions regarding the effectiveness of enhanced energization programs or the impacts of mandated targets on those programs.[11]

And San Diego Gas & Electric (SDG&E) contends:

> The Commission should not order remedial action based on data points the utility's systems cannot yet reliably produce.[12]

The IOU comments attempt to recharacterize Phase 1 targets as preliminary aspirations rather than enforceable benchmarks established pursuant to statutory requirements. The Legislature enacted Assembly Bill (AB) 50,[13] Senate Bill (SB) 410,[14] and SB 254[15] precisely because energization delays were already undermining California's climate and electrification

9 D.24-09-020, *Decision Establishing Target Energization Time Periods and Procedure for Customers to Report Energization Delays,* R.24-01-018 (Sept. 12, 2024).
10 SCE Opening Comments, at 2.
11 PG&E Opening Comments, at 3.
12 SDG&E Opening Comments, at 3.
13 Assembly Bill 50 (Wood, Ch. 317, Stats. 2023).
14 Senate Bill 410 (Becker, Ch. 394, Stats. 2023).
15 Senate Bill 254 (Becker, Ch. 119, Stats. 2025).

goals. The Commission cannot satisfy those statutes by indefinitely postponing accountability until the IOUs believe their systems are sufficiently mature.

Indeed, other parties argued the opposite of the IOUs: that the Commission should already be pursuing more aggressive timelines. Local Government Sustainable Energy Coalition (LGSEC) explains:

> …the present 182-day average energization goal represents a failure of regulatory ambition that directly hinders local government decarbonization and housing mandates. In stark contrast to international benchmarks of five to 14 days, extended utility timelines act as an administrative penalty on local progress, creating a severe gap between state innovation goals and practical execution.[16]

Likewise, Southern California Tribal Chairmen Associations (SCTCA) states:

> For comparison, average grid connection times for basic residential and small commercial service in Denmark are 60 days on average. In Indonesia energizations take just five days; Singapore, six days; and Malaysia, 14 days. Yet the CPUC has accepted an average energization goal of 182 days.[17]

These comments underscore that the Commission's existing targets are already conservative relative to international benchmarks and California's urgent policy needs. The solution to current implementation challenges is not to weaken or defer enforcement, but rather to continue improving IOU performance and reporting.

Even PG&E implicitly acknowledges that prolonged delays are harmful:

> PG&E asserts that it continues to be and always has been in the utilities' best interest to energize customers as fast as possible. Extended project timelines increase utility costs, delay customer energization, and adversely affect customer satisfaction and public perception.[18]

16 LGSEC Opening Comments, at 3.
17 SCTCA Opening Comments, at 3.
18 PG&E Opening Comments, at 3.

If prolonged timelines increase costs, delay customer energization, and undermine public confidence, then the Commission cannot reasonably conclude that postponing enforcement and enabling indefinite deferral of achieving targets will improve outcomes.

CalCCA agrees that reporting systems and data quality must continue improving. However, IOU attempts to use reporting limitations cannot continue to be used as justification for delaying accountability altogether. SDG&E argues that additional reporting and compliance measures may require further funding and system enhancements.[19] But the existence of implementation challenges does not negate the Commission's statutory obligations under SB 254. The statute does not make remedial actions discretionary once noncompliance is identified.[20] Nor does it authorize the Commission to indefinitely delay enforcement pending perfect data systems. Instead, SB 254 requires the Commission to establish remedial actions and an enforcement framework that "includes penalties" for noncompliance.[21]

Accordingly, Phase 2 should focus on strengthening implementation, refining reporting, and establishing meaningful enforcement, not retreating from the targets adopted in Phase 1.

III. SCE'S RECOMMENDATION TO USE THE RESOURCE ADEQUACY COMPLIANCE FRAMEWORK AS A MODEL AND CAL ADVOCATES' PROPOSED FORMULA FOR INCORPORATING CUSTOMER HARM INTO PENALIZING DELAYS SHOULD BOTH BE ADOPTED

CalCCA agrees with parties seeking a structured enforcement framework tied to energization performance. In particular, both SCE and Cal Advocates recognize that the

[19] SDG&E Opening Comments, at 2.

[20] Through SB 254, the Legislature added subsection (g) to section 934, mandating that the Commission "establish an ***enforcement policy*** for the targets [established in the Phase 1 Decision] that include ***penalties*** for not complying with the remedial actions required pursuant to" section 934(d). Cal. Pub. Util. Code § 934(g) (emphasis added).

[21] *Id*.

Commission should rely on existing enforcement tools and establish a graduated compliance framework that escalates when IOUs fail to improve performance.

As CalCCA explains in Opening Comments, "the Commission should adopt a framework that includes: (1) clearly defined, objective triggers for remedial action; (2) implementing a structured, escalating framework once a violation occurs; and (3) shareholder-funded penalties that build on the Commission's existing Enforcement Policy while tailoring penalty calculations to reflect actual customer harm."[22]

While SCE argues that remedial actions are currently "inappropriate and premature" because the Phase 1 targets may continue to evolve,[23] SCE nevertheless acknowledges the statutory requirement under section 934(g)[24] requiring the Commission to adopt an enforcement policy.[25] SCE similarly acknowledges that the Commission should "supplement the broadly applicable enforcement principles and penalty methodology articulated in Resolution M-4846[26] with an energization-specific enforcement plan or citation program."[27] In support of that proposal, SCE points to the Commission's Resource Adequacy (RA) compliance framework as a model for this proceeding, explaining that "the Commission may look to existing Commission enforcement structures that provide narrowly tailored schedules of violations, such as those used in the [RA] program."[28] SCE further notes that the RA framework "contains clearly defined, measurable compliance obligations and thresholds that trigger enforcement," establishes "a

22 CalCCA Opening Comments, at 5.
23 SCE Opening Comments, at 3.
24 All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.
25 SCE Opening Comments, at 10.
26 Resolution M-4846, *Resolution Adopting Commission Enforcement Policy* (Nov. 5, 2020).
27 *Ibid*.
28 *Id*., at 11.

graduated schedule of citations and penalties," and provides "advance notice of the specific requirements."[29]

Notably, SCE's proposal mirrors the framework CalCCA recommends in its Opening Comments. CalCCA likewise explained that the Commission should move beyond Resolution M-4846's generalized enforcement framework and instead adopt "a more streamlined approach to penalty assessment, similar to the [RA] compliance framework most recently modified in D.23-06-029."[30] CalCCA specifically recommends "standardized penalty amounts, calibrated to reflect typical customer harm and designed to escalate with repeated or more severe noncompliance."[31]

The Commission should adopt a graduated enforcement structure as proposed by SCE and CalCCA. Importantly, CalCCA's support for SCE's proposed RA compliance framework analogy does not reflect agreement with SCE's characterization of the Phase 1 targets as merely aspirational. Rather, the Commission should adopt the graduated enforcement structure proposed by both SCE and CalCCA, while making clear that energization timelines adopted in Phase 1 constitute enforceable performance obligations subject to remedial action and penalties pursuant to sections 934(d) and 934(g). The RA framework provides the type of predictable, transparent, and escalating enforcement structure necessary to ensure the IOUs treat energization timelines as binding obligations rather than aspirational targets.

The Commission should also adopt Cal Advocates' proposal for a shareholder-funded enforcement structure, including a penalty framework that directly incorporates customer harm into the calculation methodology. Specifically, Cal Advocates recommends that the Commission

29 *Ibid*.
30 CalCCA Opening Comments, at 9.
31 *Ibid*.

"formulate the penalty based on the number of days that the IOU average energization timeline in a given category exceeds the D.24-09-020 timeline, the size of the IOU, and a base penalty."[32] Cal Advocates further explains that "[t]he base penalty should reflect the economic harm to an average customer for each day of late energization."[33] This customer-harm-oriented approach appropriately ties penalties to the real-world impacts caused by delayed energization. As CalCCA explained in its Opening Comments, Resolution M-4846's traditional focus on the "economic benefit" to the utility "creates a misalignment in the present proceeding" because it fails to account for "the magnitude of harm imposed on customers awaiting service."[34] CalCCA therefore recommends that "the Commission should establish a performance-based penalty structure that incorporates customer harm into the calculation."[35]

In addition, the Commission should adopt Cal Advocates' recommendation that any penalties adopted in this proceeding must be shareholder funded. Cal Advocates recommends that "shareholders of the non-compliant IOU" should bear responsibility for penalties.[36] CalCCA strongly agrees, as noted in CalCCA's Opening Comments. Customers should not bear the financial burden of utility failure to meet Commission-established energization targets. A shareholder-funded penalty framework is necessary to create meaningful incentives for compliance and to ensure that utilities internalize the consequences of persistent delays.

IV. CAL ADVOCATES' RECOMMENDATIONS TO ENSURE SB 254 AUDITOR INDEPENDENCE AND EFFECTIVENESS SHOULD BE ADOPTED

The Commission should adopt Cal Advocates' recommendations regarding the implementation of the SB 254 auditor framework. As the Amended Scoping Ruling recognized

32 Cal Advocates Opening Comments, at 5.
33 *Ibid*.
34 CalCCA Opening Comments, at 9.
35 *Ibid*.
36 Cal Advocates Opening Comments, at 6.

and CalCCA explained in its Opening Comments, "auditor oversight will play a central role in evaluating IOU energization planning, performance, and compliance with Commission-ordered targets and remedial actions."[37] Without clear safeguards, "the auditor process risks becoming duplicative, opaque, or ineffective in driving meaningful improvements."[38]

Cal Advocates' assessment of the existing SB 410 audit framework demonstrates precisely why additional guardrails are necessary. Cal Advocates explains that the current framework "has not produced auditor reports that provide the Commission and parties with sufficient analysis and oversight of PG&E's performance."[39] Specifically, Cal Advocates identifies several provisions in the PG&E-Ernst & Young (EY) contract that "enable PG&E to influence and limit the scope of auditor reports," including provisions allowing PG&E and the auditor to "align on" reporting requirements, preview data samples, participate in recurring status meetings regarding audit findings, and review and edit draft reports prior to publication.[40] Cal Advocates correctly concludes that these provisions "reduce the independence of the auditor" and "compromise[] EY's independence as an auditor to the detriment of both the process and ratepayers."[41]

These concerns directly support CalCCA's recommendation that the Commission establish "clear, consistent, and transparent guidelines governing the selection, scope, and use of auditors pursuant to SB 254 and SB 410."[42] CalCCA further recommends that any joint auditor approach include "appropriate safeguards" to ensure independence and accountability.[43]

37 CalCCA Opening Comments, at 10.
38 *Ibid*.
39 Cal Advocates Opening Comments, at 10.
40 *Id*., at 10-11.
41 *Id*., at 11.
42 CalCCA Opening Comments, at 10.
43 *Ibid*.

CalCCA therefore supports Cal Advocates' proposed safeguards for the SB 254 auditor framework. In particular, CalCCA agrees that: (1) Energy Division should review auditor contracts to ensure they do not undermine auditor independence; (2) Energy Division staff should have visibility into auditor-utility interactions; and (3) the IOUs should not be permitted to review or edit draft auditor reports before publication.[44] These recommendations are reasonable and necessary to preserve the integrity of the audit process and ensure the Commission and stakeholders receive objective, actionable evaluations of IOU performance.

The Commission should also adopt Cal Advocates' recommendation that the Commission establish a formal comment process for auditor reports. As Cal Advocates explains, allowing parties and auditors to submit comments and replies on audit reports will ensure transparency, due process, and meaningful scrutiny of utility performance and audit conclusions.[45] This recommendation is consistent with CalCCA's request for a "formal process for evaluating and acting on auditor recommendations."[46]

Finally, the Commission should adopt Cal Advocates' recommendation that the Commission prohibit recovery of SB 254 audit costs from ratepayers. As Cal Advocates correctly explains, ratepayers already fund energization work through general rate cases and other Commission-authorized mechanisms, and "should not pay additional costs to ensure that the IOUs fulfill their legal requirements."[47] This conclusion is consistent with CalCCA's position throughout these comments that accountability mechanisms, including enforcement and compliance costs, should remain shareholder funded to preserve meaningful incentives for IOU performance improvement.

44 Cal Advocates Opening Comments, at 12-13.
45 *Id.*, at 13.
46 CalCCA Opening Comments, at 12.
47 Cal Advocates Opening Comments, at 15.

V. THE COMMISSION SHOULD ADOPT SCTCA'S AND SPUR'S RECOMMENDATIONS FOR ENHANCED TRANSPARENCY AND PUBLIC-FACING MONITORING AND REQUIRE ELIMINATION OF UNNECESSARY REDACTIONS IN ENERGIZATION REPORTING

As CalCCA explains in its Opening Comments, "[t]imely and accessible reporting is essential for evaluating whether adopted remedial actions are producing measurable improvements in customer outcomes," and reporting "must be frequent, standardized, and transparent to stakeholders, not limited to infrequent or high-level summaries."[48] Consistent with that principle, CalCCA recommends that the Commission require the IOUs to submit monthly progress reports to the docket and service list and require the IOUs to "publish this information through a public-facing portal, ensuring that customers, local governments, and developers can track the status of projects in real time."[49] CalCCA further recommends that the Commission require reporting frameworks that support "evaluation of performance against Commission-adopted targets and metrics, rather than merely providing descriptive information."[50]

These recommendations are reinforced by comments from other parties. SCTCA recommends that the Commission require the IOUs to provide applicants with transparent monitoring tools that allow customers to determine where their projects are in the energization process and identify the source of delays, rather than relying solely on aggregated utility reporting.[51] SCTCA also advocates for robust monitoring and verification systems capable of tracking utility performance across customer classes and project categories to support meaningful accountability and enforcement.[52]

48 CalCCA Opening Comments, at 13.
49 *Id*., at 14.
50 *Ibid*.
51 SCTCA Opening Comments, at 6.
52 *Ibid*.

Likewise, San Francisco Bay Area Planning and Urban Research Association (SPUR) recommends that the Commission require the IOUs to consolidate their biannual energization reporting into a single, centralized public-facing dashboard modeled after the Commission's Distributed Generation statistics platform.[53] SPUR explains that a centralized statewide dashboard would allow customers, policymakers, and the Commission to identify where energization bottlenecks persist across utility territories and would create additional accountability pressure for utilities to address ongoing reporting gaps and IT limitations.[54] This biannual statewide dashboard should complement, not replace, the more frequent monthly progress reporting and project-level transparency measures supported by CalCCA. Together, these reporting tools would provide both near-term visibility into ongoing project status and broader statewide trend analysis necessary to evaluate utility performance over time.

Additional transparency reforms are warranted given continuing inconsistencies and omissions in utility reporting. For example, PG&E's Energization Reports redact information such as the city in which projects are located and the applicable Authority Having Jurisdiction, making it difficult for LSEs and stakeholders to identify geographic bottlenecks or recurring jurisdictional delays across PG&E's service territory.[55] Other IOUs do not uniformly redact this information, demonstrating that more transparent and standardized reporting practices are both feasible and appropriate.[56] The Commission should therefore require consistent statewide reporting standards that provide sufficiently granular information to identify systemic energization constraints while preserving appropriate customer confidentiality protections.

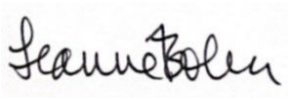
53 SPUR Opening Comments, at 6.
54 *Ibid*.
55 For example, *Attachment A to PG&E March 2026 Biannual Energization Report (Public)*.
56 For example, SDG&E *Public Attachment B Energization Report 3.31.26*.

Enhanced transparency and standardized monitoring will improve accountability, support more effective remedial actions and enforcement policies, and better enable CCAs and other stakeholders to plan for and serve new load growth efficiently and affordably.

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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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 IN RESPONSE TO ASSIGNED COMMISSIONER'S RULING ISSUING QUESTIONS ON THE ELECTRIFICATION IMPACT STUDY PART 2 FINAL REPORTS

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends that the Commission:

- Take a methodical approach to evaluating and improving the EIS2 modeling before incorporating the results into the DPEP, by:
    - Aligning planning assumptions with current and anticipated rules and regulations to support policy objectives;
    - Refining assumptions used in the demand flexibility scenarios to inform strategies for achieving greater cost reductions; and
    - Improving methods for identifying and modeling granular locational grid constraints, demand flexibility potential, and grid deferral opportunities to improve modeling accuracy.

[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 IN RESPONSE TO ASSIGNED COMMISSIONER'S RULING ISSUING QUESTIONS ON THE ELECTRIFICATION IMPACT STUDY PART 2 FINAL REPORTS

California Community Choice Association[2] (CalCCA) submits these comments pursuant to the *Assigned Commissioner's Ruling Issuing Questions on the Electrification Impact Study Part 2 Final Reports*[3] (Ruling), dated May 8, 2026. The Ruling seeks responses from interested parties on questions about the Electrification Impact Study Part 2 (EIS2) Final Reports submitted by Pacific Gas and Electric Company[4] (PG&E), Southern California Edison Company[5] (SCE), and San Diego Gas & Electric Company[6] (SDG&E) (collectively, the investor-owned utilities (IOUs)), on January 28, 2026.

[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, Peninsula Clean Energy, 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, and Valley Clean Energy.

[3] *Assigned Commissioner's Ruling Issuing Questions on the Electrification Impact Study Part 2 Final Report*[3] Rulemaking (R.) 21-06-017 (May 8, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M606/K215/606215448.PDF.

[4] *Pacific Gas and Electric Company's (U 39 E) Electrification Impacts Study Part 2 Report*, R.21-06-017 (Jan. 28, 2026) (PG&E EIS2), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K907/596907812.PDF.

[5] *Southern California Edison Company's (U 338-E) Electrification Impacts Study Part 2 Final Report*, R.21-06-017 (Jan. 28, 2026) (SCE EIS2), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K907/596907811.PDF.

[6] *San Diego Gas & Electric Company's (U 902 E) Final Electrification Impact Study Part 2*, R.21-06-017 (Jan. 28, 2026) (SDG&E EIS2), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K903/596903988.PDF.

I. INTRODUCTION

The purpose of EIS2 is to inform the Distribution Planning and Execution Process (DPEP) about the potential need and cost for grid upgrades under various electrification and demand flexibility scenarios.[7] Given that California already has some of the highest electricity rates in the nation, the IOUs must utilize methods to minimize costs of upgrading the grid to support electrification goals while maintaining or improving grid reliability. The EIS2 Final Reports represent the IOUs' first attempts to quantify the potential costs of meeting this objective under various electrification and demand flexibility scenarios. The IOUs should continue to refine the EIS2 recommendations to ensure they capture changes in policies, distributed energy resource (DER) technologies, and trends in energization and DER adoption. Refining EIS2 should also improve modeling accuracy to reliably inform grid infrastructure needs and deferral opportunities.

CalCCA supports efforts to incorporate the potential impacts of electrification and demand flexibility into the DPEP to identify grid needs and potential cost-mitigation opportunities. Prior to incorporating EIS2 learnings into the DPEP, however, the Commission should require improvements to IOU modeling in at least two ways. *First,* changes in regulatory policies and technological advances require that EIS2 modeling techniques and assumptions continually evolve. Issues being addressed in other Commission proceedings, including but not limited to DER orchestration, dynamic rates, and improvements to DER interconnection and energization processes, may significantly impact these grid planning efforts. The Commission should therefore take a methodological and holistic approach, as discussed further below, before requiring the IOUs to incorporate the EIS2 learnings into the DPEP.

[7] Decision (D.) 24-10-030*, Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps*, R.21-06-017 (Oct. 23, 2024) (Distribution Planning Decision), at 97, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF.

Second, the IOUs each used vastly different modeling approaches and assumptions, leading to varying and likely inconsistent cost-reduction estimates for their respective demand flexibility scenarios. The different assumptions made by IOUs, such as unrealistically high demand flexibility participation rates or the ability to perfectly orchestrate DERs, can impact the future grid infrastructure upgrades and cost savings opportunities. The EIS2 modeling must therefore strike a balance between being overly optimistic and overly pessimistic to maximize achievable cost savings while maintaining grid reliability and minimizing energization and interconnection times. Achieving this balance requires continual updates to modeling techniques and assumptions, building on lessons learned from each successive DPEP. The Commission should therefore require the IOUs to continuously refine their methodologies and assumptions to ensure accuracy and to inform strategies for achieving greater cost reductions, particularly if EIS2 learnings are to be incorporated into the DPEP.

In addition to providing responses to the Ruling questions, CalCCA first provides general comments and recommendations herein on incorporating the EIS2 into the DPEP. As set forth below, CalCCA recommends that the Commission:

- Take a methodical approach to evaluating and improving the EIS2 modeling before incorporating the results into the DPEP, by:
    - Aligning planning assumptions with current and anticipated rules and regulations to support policy objectives;
    - Refining assumptions used in the demand flexibility scenarios to inform strategies for achieving greater cost reductions; and
    - Improving methods for identifying and modeling granular locational grid constraints, demand flexibility potential, and grid deferral opportunities to improve modeling accuracy.

II. THE COMMISSION SHOULD TAKE A METHODICAL APPROACH TO EVALUATING AND IMPROVING THE EIS2 MODELING BEFORE INCORPORATING THE RESULTS INTO THE DPEP

The Commission should take a methodical approach to evaluating and improving the EIS2 modeling approaches used by the IOUs before incorporating the results into future DPEP cycles.[8] As noted in CalCCA's Comments on the Draft EIS2 Reports, the IOUs should be required to refine their assumptions and methodologies to ensure they are more realistic and achievable, and to inform strategies that achieve greater distribution cost reductions.[9] Specifically and as set forth below, the Commission should require the following prior to the EIS2 reliably informing future distribution planning efforts: (1) the alignment of planning assumptions with current and anticipated rules and regulations to support policy objectives; (2) the refinement of assumptions used in the IOU demand flexibility scenarios to inform strategies for achieving greater cost reductions; and (3) the improvement of methods for identifying and modeling granular locational grid constraints, demand flexibility potential, and grid deferral opportunities to improve modeling accuracy.

A. The IOUs Should Refine the Planning Assumptions with Current and Anticipated Rules and Regulations to Support Policy Objectives

The regulatory landscape impacting electrification, demand flexibility, and DER deployment has changed significantly since the Commission's Distribution Planning Decision and continues to evolve, requiring the IOUs to undertake EIS2.[10] The IOUs should be required to

[8] The Ruling correctly identifies the improbability of incorporating the EIS2 learning into the next DPEP cycle due to IOUs' delays in submitting their respective reports. *See* Ruling, at 2. However, the Ruling fails to identify the need to improve the EIS2 modeling methodologies and assumptions, or to align the planning assumptions with current and anticipated policies, before incorporating the EIS2 learnings in the 2027-2028 DPEP cycle.

[9] *See California Community Choice Association's Comments on Pacific Gas and Electric Company's, San Diego Gas & Electric Company's, and Southern California Edison Company's Draft Electrification Impact Study Part 2 Reports*, R.21-06-017 (Dec. 15, 2025) (Draft EIS2 Comments), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M591/K255/591255769.PDF.

[10] *See* Distribution Planning Decision.

refine their assumptions and modeling to incorporate these regulatory changes and support policy objectives, as the Commission acts on them, before they are incorporated into the planning process. For example, the Commission's recent DER Orchestration Ruling is evaluating approaches to developing a framework for orchestrating DERs, which could have a major impact on DER adoption and associated grid-impact mitigation measures.[11] Other proceedings are addressing improvements to processes for energizing loads[12] and interconnecting DERs,[13] which will impact the timing and pace of electrification and the ability of DERs to mitigate the need for grid upgrades. Demand response and dynamic rates are also currently being addressed in past and recently opened Commission proceedings,[14] and in individual IOU General Rate Case proceedings.

Though the outcomes of those and other proceedings remain uncertain, they could significantly impact the timing, location, and magnitude of electrification, demand flexibility measures, and DER adoption. The Commission should therefore require the IOUs to incorporate ongoing refinements to their EIS2 modeling and assumptions into their DPEP processes to account for policy changes, new rates and programs, and technology enhancements such as demand flexibility marketplaces and DER orchestration platforms.

[11] *See Assigned Commissioner's Ruling on Track 1 and Track 2 Distributed Energy Resources Orchestration*, R.21-06-017 (Mar. 23, 2026) (DER Orchestration Ruling), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K997/602997407.PDF.

[12] *See Order Instituting Rulemaking to Establish Energization Timelines,* R.24-01-018 (Jan. 30, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M524/K427/524427971.PDF.

[13] *See Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulation*, R.25-08-004 (Aug. 20, 2025), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M576/K867/576867418.PDF.

[14] *See Order Instituting Rulemaking to Enhance Demand Response in California,* R.25-09-004 (Sep. 29, 2025) ("evaluat[ing] and enhance[ing] the consistency, predictability, reliability, and cost-effectiveness of demand response resources"); *see also Order Instituting Rulemaking on California Advanced Rate Design,* R.26-04-009 (Apr. 9, 2026) (addressing "send[ing] price signals that support efficient use of grid infrastructure"); *see also Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates,* R.22-07-005 (July 14, 2022) (closed proceeding which analyzed demand flexibility principles, and ordered dynamic pricing pilots).

B. The IOUs Should Refine the Assumptions Used in the Demand Flexibility Scenarios to Inform Strategies for Achieving Greater Cost Reductions

The IOUs should refine their assumptions for their demand flexibility scenarios and perform additional sensitivity analyses to inform distribution planning strategies that achieve greater cost reductions and system benefits. As CalCCA highlighted in its Comments on the Draft EIS2, PG&E's and SCE's Demand Flexibility Scenarios showed only modest cost savings compared to their base scenarios.[15] SDG&E's Demand Flexibility Scenario did not independently investigate demand flexibility options to mitigate grid upgrades.[16] SDG&E characterized the Equity and Demand Flexibility Scenario as "hypothetical "what-if" situations that carry little weight in terms of anticipating the infrastructure that will be needed to meet future, real world needs."[17]

Demand flexibility offers tremendous potential to reduce grid upgrade costs, particularly as transportation and building electrification are expected to grow. The recent DER Orchestration Ruling intends to enhance the ability of DERs to provide beneficial grid services, stating:

> DER orchestration aims to create efficiency by increasing capacity utilization, avoiding capacity upgrades, and unlocking operational efficiencies. If successful, DER orchestration may contribute to ratepayer cost reductions once operational.[18]

For DER orchestration to be successful, the IOUs must be diligent in finding opportunities for DER to reduce the need for capacity upgrades. The Commission should therefore require the IOUs to continue to refine their modeling techniques and assumptions to unlock potential ratepayer cost reductions offered by demand flexibility and envisioned by the Commission's DER Orchestration Ruling.

15 CalCCA Comments on Draft EIS2, at 4.
16 *Ibid*.
17 SDG&E EIS2, at 34.
18 DER Orchestration Ruling, at 5.

C. The IOUs Should Improve Methods for Identifying and Modeling Granular Locational Grid Constraints, Demand Flexibility Potential, and Grid Deferral Opportunities to Improve Modeling Accuracy

The IOUs should also continue to refine assumptions and modeling methods for granular locational grid constraints, demand flexibility potential, and grid deferral opportunities to improve accuracy and maximize cost savings. CalCCA's Draft EIS2 Comments included recommendations for revising assumptions in the IOUs' Draft EIS2 Reports, which were unrealistic or based on preliminary modeling. The IOUs modified some of these assumptions in their final EIS2 Reports in response to stakeholder feedback, but the reports did not make clear whether and how they incorporated stakeholder or Commission feedback.

For example, in response to CalCCA's Comments on the Draft EIS2 recommendation that PG&E reassess its assumptions for new transformers on the secondary system, it merely cites the section number, which contains no discussion of the changes from the Draft EIS2 Report.[19] Since no additional workshops were held after the Final EIS2 Reports were submitted, it is difficult to understand which assumptions were changed and what impact those changes had.

CalCCA also recommended that SCE modify its assumption for 100 percent program participation for several categories of demand flexibility end uses in its Alternate Demand Flexibility Scenario, arguing that the assumption "is not a reliable planning assumption and should be revised to reflect levels that are both realistic and attainable."[20] However, the SCE EIS2 still included the unrealistic 100 percent participation rate assumption for this scenario. In response to a recommendation from the Commission's Energy Division (ED) to explain the relative contribution of various end uses to peak demand under each scenario, SCE stated:

[19] PG&E EIS2, at 126.
[20] CalCCA Comments on Draft EIS2, at 7.

> Addressing this feedback would require additional analysis that cannot be completed by the deadline for the final report.[21]

These examples highlight the need for the IOUs to continue refining their assumptions and modeling capabilities to produce accurate, reliable results that inform future distribution planning and infrastructure needs.

III. CALCCA'S RESPONSES TO QUESTIONS ON EIS2 RESULTS AND IMPLEMENTATION PROPOSALS

1. How should the findings of the EIS2 inform the yearly DPEP?

The findings of the EIS2 should be incorporated into the annual DPEP only after the IOUs refine their modeling methodologies and assumptions, and not before the 2027-2028 DPEP cycle, as discussed in Section II. above. The Commission should instead take a methodical approach to evaluating and improving the EIS2, requiring the IOUs to refine assumptions and modeling capabilities in parallel with the DPEP and adopt learnings from each successive planning cycle. The IOUs should report on these changes during the annual Distribution Forecasting Working Group (DFWG) and Distribution Planning Advisory Group (DPAG) workshops to ensure transparency and to receive stakeholder input.

2. (For each utility) What are the principal learnings and capabilities developed through the EIS2? How can learnings from the EIS2 be used in the annual DPEP to minimize infrastructure costs and maximize ratepayer benefits associated with electrification?

CalCCA has no response at this time.

a. How can the IOUs integrate EIS2 load flexibility findings into distribution planning needs assessments for the DPEP to seek opportunities to reduce capital costs when assessing distribution planning needs?

CalCCA has no response at this time.

[21] SCE EIS2, at 62.

3. Given projected load growth and increasing electrification needs, how should findings from the equity scenario inform the Commission's approach to ensuring that disadvantaged communities do not experience unreasonable delays in necessary grid upgrades?

CalCCA has no response at this time.

4. The EIS2 models enhanced demand flexibility and the coordinated management of DERs as a cost-saving tool to reduce future distribution infrastructure investment needs. Are the underlying assumptions of demand flexibility (including the scale of DER participation, load flexibility response rates, and timing of deployment) sufficiently supported by current data to be reliable as inputs for distribution planning and cost forecasting?

a. If yes, how will the utilities incorporate these assumptions into future DPEP cycles?

b. If not, what must utilities demonstrate to establish that those projections are sufficiently reliable, and what time frame expectations should the Commission establish?

As discussed in Section II. above, several regulatory proceedings are underway that could have a substantial impact on DER adoption and demand flexibility participation. Chief among these is the DER Orchestration discussion in the High DER proceeding, which will determine the framework for coordinating DERs. CalCCA believes that a framework that incorporates an independent marketplace as the primary means for IOUs to acquire demand flexibility will provide greater opportunities for non-IOU-managed DERs to provide grid services, provided the Commission addresses potential IOU conflicts of interest.[22] The selection of a framework will also influence load flexibility response rates and the timing of DER deployment.

The IOUs' EIS2 Reports provided assumptions about the level of DER adoption and demand flexibility participation, and the impact on peak demand under different scenarios. As discussed in Section II.C. above, the IOUs did not fully address stakeholder or ED concerns

[22] CalCCA clarifies that an independent marketplace is not the same as an independent distribution system operator (DSO). An independent marketplace can exist under an IOU-led DSO framework but requires additional guardrails to prevent IOU conflicts of interest.

regarding some assumptions, such as SCE's assumption of 100 percent program participation in its Alternative Demand Flexibility Scenario. The IOUs should continue to refine these and other assumptions and seek stakeholder feedback through the DFWG, DPAG, or other forums before incorporating them into the DPEP.

5. The EIS2 evaluates a range of three to four electrification and demand flexibility scenarios with distinct assumptions regarding distribution system impacts in the respective IOU service territories. Should assumptions from these scenarios be treated as exploratory and in need of further refinement before they can be used to guide investments in utility distribution infrastructure?

As discussed in Section II. above, the assumptions require additional refinement before incorporating the results into the DPEP. The EIS2 findings could provide valuable input to guide grid infrastructure investment decisions, with further refinement of both the assumptions and modeling methodologies. Demand flexibility and orchestrated DER are powerful tools for avoiding costly grid upgrades, and the Commission should require the IOUs to find opportunities to leverage these resources. However, until the EIS2 assumptions and modeling deficiencies are adequately addressed, the Commission should proceed cautiously before fully incorporating the results into the DPEP.

a. Which scenarios contain elements of cost estimation methodology most appropriate for informing future distribution planning activities?

CalCCA has no response at this time.

b. To what extent should assumptions from these scenarios inform forecasting assumptions used in the yearly DPEP (e.g., under the scenario planning framework)?

Assumptions from the EIS2 scenarios should be presented to stakeholders through the annual DFWG and DPAG efforts, similar to the California Energy Commission's Integrated Energy Policy Report process. Stakeholders should be given the opportunity to review and

comment on these assumptions to help the Commission determine which are reliable enough to inform the DPEP forecast, and which require further refinement. This will provide greater transparency and generate greater confidence in the assumptions, which can then be used to guide investment decisions.

6. Does EIS2 reveal any methodological or analytical limitations that should be considered before applying its findings in regulatory planning processes?

Each IOU used a different modeling approach, set of inputs, and assumptions in their EIS2, employing varying degrees of sophistication and producing different results. Each modeling approach, and the inputs and assumptions that inform the model, must be refined and evaluated before applying their findings to the DPEP. As discussed in response to previous questions, the Commission should require the IOUs to present their EIS2 assumptions and results through the DFWG and DPAG processes and incorporate stakeholder feedback. This methodical approach will improve the accuracy and reliability of EIS2, informing future planning processes and grid investment decisions.

PG&E's approach to modeling the impacts on its secondary system was the most detailed and sophisticated of the three IOUs, but it was only recently developed. Given that it is untested, PG&E should continue to refine the model and evaluate the results alongside its normal distribution planning approach to ensure it accurately predicts necessary grid upgrade investments.

SCE's approach relied on a "partially automated decision tree methodology to identify recommended mitigation measures, which differs from the traditional Distribution Planning Process (DPP) that relies on a team of engineers to select the most cost-effective solutions."[23] SCE explained that this approach was used "to allow four scenarios to be analyzed in the time it

[23] SCE EIS2, at 5.

typically takes to analyze a single scenario within the DPP."[24] Similar to PG&E, SCE's approach is untested and should be refined alongside the standard planning process so that the results can be evaluated before being incorporated into the DPEP.

Finally, SDG&E took a simplified approach using existing datasets, adding a validation step, and relying on consultants and Lawrence Berkeley National Laboratory for inputs and analysis to inform its Demand Flexibility Scenario.[25] As discussed in Section II.B. above, SDG&E seems to cast doubt on the usefulness of its Equity and Demand Flexibility Scenarios beyond a hypothetical thought experiment. SDG&E should modify its EIS2 methodology, inputs, and assumptions to align more closely with those of the other IOUs, to the extent practicable.

a. What factors need to be considered or further validated before incorporating EIS2 findings directly into future planning processes?

See response to question 6., above.

b. Please identify the specific aspects of the study where additional clarification or analysis may be warranted.

See response to question 6., above.

7. SCE discusses the potential for distributed energy storage to operate as a flexible grid asset capable of supporting demand flexibility and reducing distribution infrastructure needs.

a. How can the IOUs model a flexible grid asset with this capability in the DPEP?

CalCCA has no response at this time.

b. What are the limitations to modeling an asset of this type that should be addressed first, if any?

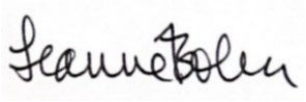
CalCCA has no response at this time.

[24] *Ibid*.
[25] SDG&E EIS2, at 1-2.

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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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulations.	R.25-08-004

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends that the Commission:

- Adopt meaningful timeline compliance enforcement measures as proposed by IREC, CALSSA, CESA, and United; and
- Establish or modify timelines for non-NEM/NBT, small NEM, and multifamily/VNEM projects as proposed by IREC, CALSSA, Tesla, and SEIA, including:
    - Modifying timelines for non-NEM/NBT systems smaller than 1 MW to be the same as those for comparably-sized NEM/NBT systems;
    - Establishing timelines for NEM projects smaller than 30 kVA; and
    - Establishing timelines for specific steps within the multifamily/VNEM interconnection process.

[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 Distribution Level Interconnection Rules and Regulations.	R.25-08-004

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to the *Assigned Commissioner's Scoping Memo and Ruling*[3] (Ruling), dated March 3, 2026, and the *Email Ruling Granting Extension for Comments, Motion to Late File NOI, and Motions for Party Status*,[4] dated March 6, 2026.

I. INTRODUCTION

Opening Comments[5] from the Interstate Renewable Energy Council (IREC), the California Solar and Storage Association (CALSSA), the California Energy Storage Alliance (CESA), and Advanced Energy United (United) support the California Public Utilities Commission's (Commission) adoption of meaningful timeline compliance measures to address

[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, Peninsula Clean Energy, 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, and Valley Clean Energy.

[3] *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking (R.) 25-08-004 (Mar. 3, 2026).

[4] *Email Ruling Granting Extension for Comments, Motion to Late File NOI, and Motions for Party Status*, R.25-08-004 (Mar. 6, 2026).

[5] Opening Comments refer to party opening comments submitted into this proceeding on or about April 30, 2026.

longstanding interconnection delays, particularly those in the service territories of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE). IREC's and CALSSA's Opening Comments also describe the negative financial consequences for distributed energy resource (DER) project developers, and the potential impacts on affordability and meeting the state's clean energy goals. Both IREC and CALSSA propose specific compliance measures with timelines in their Opening Comments, echoing similar recommendations in CalCCA's Opening Comments.

CalCCA also supports Opening Comments from IREC, CALSSA, Tesla, Inc. (Tesla), and the Solar Energy Industries Association (SEIA), recommending new or modified interconnection timelines for non-Net Energy Metered (NEM)/Net Billing Tariff (NBT), small NEM, and multifamily/virtual NEM (VNEM) projects. These new and modified timelines will streamline and accelerate interconnection timelines and should be adopted by the Commission.

As set forth below, CalCCA recommends that the Commission:

- Adopt meaningful timeline compliance enforcement measures as proposed by IREC, CALSSA, CESA, and United; and
- Establish or modify timelines for non-NEM/NBT, small NEM, and multifamily/VNEM projects as proposed by IREC, CALSSA, Tesla, and SEIA, including:
    - Modifying timelines for non-NEM/NBT systems smaller than 1 megawatt (MW) to be the same as those for comparably-sized NEM/NBT systems;
    - Establishing timelines for NEM projects smaller than 30 kilovolt-amperes (kVA); and
    - Establishing timelines for specific steps within the multifamily/VNEM interconnection process.

II. MEANINGFUL TIMELINE ENFORCEMENT MEASURES AS PROPOSED BY IREC, CALSSA, CESA, AND UNITED SHOULD BE ADOPTED

Meaningful timeline enforcement measures, as recommended by IREC, CALSSA, CESA, and United, should be adopted. These party Opening Comments describe ongoing failures of both PG&E and SCE in meeting timelines established in D.20-09-035.[6] IREC states that PG&E and SCE "have persistently missed the Commission's compliance threshold, often by wide margins and across multiple steps in the interconnection process."[7] CALSSA asserts that "the Commission has nearly five years of data showing that PG&E and SCE routinely violate existing timelines."[8]

These parties also note that interconnection delays cause financial harm to project developers and may hinder the state's efforts to advance clean energy objectives. IREC points out that delays "translate into fewer and more expensive distributed generation projects, as utility lag increases costs and threatens project viability."[9] CESA adds "[t]imeline non-compliance is not a minor procedural issue, it directly delays deployment of the DERs that California needs to meet its reliability and climate goals, and imposes real costs on developers and ratepayers alike."[10] Finally, CALSSA argues that the lack of timeline certainty "discourages customers and companies from investing in distributed clean energy."[11]

CalCCA agrees that persistent interconnection delays impede the ability of DERs to defer or avoid grid investments triggered by the rapid pace of electrification, potentially increasing

6 *See Decision (D.) 20-09-035, Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup*, R.17-07-007 (Sept. 24, 2020).
7 IREC Opening Comments, at 1.
8 CALSSA Opening Comments, at 15.
9 IREC Opening Comments, at 1-2.
10 CESA Opening Comments, at 4.
11 CALSSA Opening Comments, at 16.

costs to ratepayers. Interconnection delays can also constrain the investor-owned utilities' (IOU) ability to offer flexible connection options employing DERs for customers energizing on constrained circuits. The Commission should therefore adopt measures to ensure compliance with the timeline and accelerate DER interconnection, reducing costs for project developers, customers, and ratepayers.

CALSSA and IREC each propose measures to address IOU noncompliance with existing timelines. For its part, CALSSA proposes both one-time fines for PG&E and SCE for past violations spanning five years and restates its proposal for a tiered penalty framework,[12] which CalCCA supported in its Opening Comments.[13] IREC takes a different approach, relying on the Commission's authority to issue penalties through a citation process and highlighting its use to enforce compliance with existing Commission programs.[14]

CALSSA and IREC also recommend that the Commission follow the Federal Energy Regulatory Commission's lead and eliminate Rule 21's reasonable efforts standard for timeline compliance. CALSSA states that this Rule 21 provision "requires the utility to take actions that could have been expected to meet the timeline and further reflect the care that would have been taken if the utility itself had been the customer."[15] IREC further explains:

> To establish that a utility has failed to use reasonable efforts, an aggrieved party would have to file a formal complaint or persuade Commission staff to open an investigation.[37]Both pathways are slow, resource-intensive, and rarely pursued by interconnection applicants, who typically lack the time, capital, and litigation appetite to contest a missed deadline while their project sits idle and their financing clock runs.[16]

12 *Id*., at 34-36.
13 CalCCA Opening Comments, at 5-8.
14 IREC Opening Comments, at 18-19.
15 CALSSA Comments, at 24.
16 IREC Opening Comments, at 13-14.

Finally, IREC argues that "the Commission must recognize that the reasonable efforts standard, as applied to Rule 21 timeline compliance, is ineffective and insufficient to meet Commission enforcement principles."[17]

CalCCA concurs with Party Opening Comments that interconnection delays have serious consequences for project developers and ratepayers, and that the Commission must adopt compliance mechanisms that will result in meaningful improvements in meeting timelines. The Commission should either adopt a tiered penalty structure, as proposed by CALSSA, or a citation process as IREC proposes. CalCCA also supports IREC's and CALSSA's calls to eliminate the Rule 21 reasonableness standard to ensure IOU compliance with interconnection timelines.

III. THE COMMISSION SHOULD ESTABLISH OR MODIFY TIMELINES FOR NON-NEM/NBT, SMALL NEM, AND MULTIFAMILY PROJECTS AS PROPOSED BY IREC, CALSSA, TESLA, AND SEIA

CalCCA agrees with party recommendations to establish or modify timelines for non-NEM/NBT, small NEM, and multifamily projects to streamline and accelerate interconnection processes. CALSSA and Tesla propose that non-NEM/NBT systems below 1 MW, including non-export solar and/or storage expansions, exporting standalone storage, and vehicle-to-grid (V2G), have timelines equivalent to their NEM/NBT counterparts. IREC recommends establishing timelines for NEM projects with capacities below 30 kVA to ensure they are included in compliance tracking and enforcement. Finally, CALSSA and SEIA propose adding tracking steps to the interconnection process for multifamily projects, including VNEM, Virtual NBT (VNBT), and Solar on Multifamily Affordable Housing (SOMAH) projects.

[17] *Ibid*.

A. Timelines for Non-NEM/NBT Systems Smaller than 1 MW Should be Modified to Be Equivalent to those for Comparably-Sized NEM/NBT Systems

CALSSA contends that non-NEM systems below 1 MW, such as "non-export solar and/or storage expansions, exporting standalone storage, and V2G … should not incur more time for the IOU to review than residential-scale NEM/NBT systems."[18] CALSSA states that "[s]uch projects are not technically more complex and do not create any novel risks to the grid."[19] Finally, CALSSA argues that "smaller-scale, non-NEM systems should be faster to review" than systems between 30 kilowatts (kW) and 1 MW, and should have shorter processing times, which should also be applied to other similarly-sized systems.[20]

Likewise, Tesla suggests that a timeline similar to the one established for NEM/NBT projects up to 1 MW should be established for "residential-scale non-NEM/NBT systems provided such systems do not trigger the need for supplemental review."[21] Tesla explains that:

> Residential-scale non-NEM systems like standalone storage systems, non-exporting solar-plus-storage additions and vehicle-to-grid systems are quite comparable to residential scale NEM/NBT projects in terms of their grid impacts and level of standardization, and as such should have similar expectations in terms of the timeline to complete the interconnection review process as NEM/NBT projects.[22]

CalCCA agrees that these residential-scale non-NEM/NBT systems are similar to their NEM/NBT counterparts and should have the same processing times. The Commission should therefore adopt CALSSA's and Tesla's recommendations to establish a 30-business-day timeline for the review and processing of non-NEM systems below 1 MW. Furthermore, the Commission

18 CALSSA Comments, at 19.
19 *Ibid*.
20 *Ibid*.
21 Tesla Opening Comments, at 5.
22 *Ibid*.

should adopt CALSSA's proposal to establish a 20-business-day timeline for smaller non-NEM systems with a capacity of 30 kW or less, since these systems require less time to review.

B. Timelines for NEM Projects Smaller Than 30 KVA Should be Established

Timelines for NEM projects smaller than 30 kVA should be established, as recommended by IREC. IREC states that "standard NEM projects under 30 kVA … are not currently covered by the interconnection timelines," but that they "are relatively simple to process and project applicants benefit from speedy interconnection."[23] IREC suggests that the Commission require that these smaller NEM projects be subject to timeline tracking and reporting, arguing that omitting them from enforcement "risks utility underinvestment in application processing for that segment."[24] CalCCA concurs and recommends that the Commission establish an interconnection timeline-tracking and reporting process for NEM projects under 30 kVA.

C. Timelines for Specific Steps in the Multifamily/VNEM Interconnection Process Should be Established

Timelines for specific steps in the multifamily/VNEM interconnection process should be established, as recommended by parties. CALSSA identifies the need to establish timelines for each step in the interconnection process for multifamily/VNEM projects, reasoning that:

> Multifamily projects, consisting of VNEM, VNBT, and SOMAH projects, often experience [disproportionately] long interconnection timelines compared to single-meter projects. Since multifamily projects often consist of lower income renters, and including lower income renters is a critical component of the state's climate and affordability goals, the Commission should establish timeline certainty for these projects.[25]

[23] IREC Opening Comments, at 30.
[24] *Id*., at 31.
[25] CALSSA Opening Comments, at 22-23.

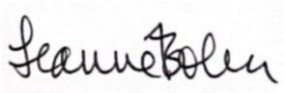
CALSSA explains that multifamily projects "interact with utility staff across multiple departments, including interconnection and service planning, and require many touchpoints with various utility staff."[26]

Similarly, SEIA states that VNEM projects require more interaction with utility staff than other projects, leading to "a longer interconnection process and more points in the process for delay and bottlenecks."[27] SEIA submits that VNEM projects should have their own set of timelines within Rule 21 and defines multiple steps in the interconnection process that should have specific timelines. CalCCA recommends that the Commission adopt the proposals from CALSSA and SEIA to establish specific steps with associated timelines within the multifamily/VNEM interconnection process.

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

May 29, 2026

[26] *Id*., at 23.
[27] SEIA Opening Comments, at 54.