JUNE FILINGS

California Community Choice Association

SUBMITTED 06/10/2025, 02:17 PM

Contact
Shawn-Dai Linderman (shawndai@cal-cca.org)

1. Please provide a summary of your organization's comments on the May 28, 2025 working group discussion.

The California Community Choice Association (CalCCA) appreciates the opportunity to submit comments on the May 28, 2025, working group meeting. In summary, the California Independent System Operator (CAISO) should:

- Revise its proposed path forward for representing nonlinearity to implement a Master File parameter expeditiously, and in the interim, direct storage resources to use the "Technical Limitations Not in the Market Model" outage card, for the reasons described in CalCCA's May 22, 2025, comments;[1] and

Seek to clearly differentiate between other instances where storage bid cost recovery (BCR) is either "warranted" or "unwarranted" and begin tailoring solutions to those differences.

---

[1] *See CalCCA Comments on May 9 Working Group Meeting* (May 22, 2025): https://stakeholdercenter.caiso.com/Comments/AllComments/a278055e-4347-4ae8-bfd5-abdc49e61dad.

2. Please provide your organization's comments on the topics related to Outage Management, particularly on the different means to represent foldback in the near-term and their relationship to availability incentives.

CalCCA reiterates its previous position. That is, the CAISO should revise its proposed path forward for representing nonlinearity to implement a Master File parameter expeditiously, and in the interim, direct storage resources to use the "Technical Limitations Not in the Market Model" outage card, for the reasons described in CalCCA's May 22, 2025, comments.[1] As an interim measure, the CAISO and/or the Department of Market Monitoring should review and validate the use of the "Technical Limitations Not in the Market Model" outage card to ensure that its use depicts actual physical constraints as intended by this stakeholder initiative and that it is not being misused. The CAISO should seek to finalize the near-term solution and communicate it to stakeholders as soon as possible so that scheduling coordinators have clarity on how to represent nonlinearity.

---

[1] *Ibid.*

3. Please provide your organization's comments on Uplift & DEB: Insights into Charging Bid Mitigation.

CalCCA appreciates the CAISO's analysis on charging bid mitigation and how it impacts storage bids and states of charge. The *Storage Bid Cost Recovery [BCR] and Default Energy Bids Enhancements* stakeholder initiative revealed that it will be important to consider instances of mitigation when determining how to apply BCR to storage resources. As a next step, the CAISO and stakeholders should clearly differentiate between other instances where BCR is either "warranted" or "unwarranted" and begin tailoring solutions to those differences.

4. Please provide your organization's comments on the PG&E's presentation.

CalCCA has no comments on Pacific Gas and Electric Company's presentation at this time.

5. Please provide any additional comments.

CalCCA has no additional comments at this time.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
OPENING COMMENTS ON THE PROPOSED DECISION

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Lauren Carr,
Senior Market Policy Analyst
Eric Little,
Director of Market Design

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
(510) 980-9459
E-mail: regulatory@cal-cca.org

June 11, 2025

TABLE OF CONTENTS

Table of Contents continued

TABLE OF AUTHORITIES

California Public Utilities Commission Decisions

California Public Utilities Commission Proceedings

California Public Utilities Commission Rules of Practice and Procedure

California Public Utilities Commission Rulings

SUMMARY OF RECOMMENDATIONS

- Modify the PD[1] to adopt hourly load obligation trading, a common-sense, cost-saving reform that has been extensively vetted and clearly identified as a market need;
- Modify the PD to adopt a system waiver rather than an effective PRM that unnecessarily exceeds the amount needed to meet a 1-in-10 LOLE;
- Clarify that the intent of the local RA CPE data request is to reduce the CPE requirement based on the aggregated contract data, while maintaining the ability for LSEs to sell to the CPE; and
- Modify the PD to remove the requirement for future RA contracts to specify that IR and RC revenues shall be allocated to the LSE as it is unnecessary to prevent double payment.

---

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 Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
OPENING COMMENTS ON THE PROPOSED DECISION**

The California Community Choice Association[2] (CalCCA) submits these Opening Comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[3] on the proposed *Decision Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements*[4] (PD), dated May 22, 2025.

I. INTRODUCTION

The PD's rejection of an hourly load obligation trading mechanism is unjustifiable. The PD advances three reasons for rejecting hourly load obligation trading: (1) it is "premature" to determine that transactability concerns exist under the slice-of-day (SOD) framework; (2) CalCCA's load obligation trading proposal fails to address "critical issues"; and (3) the proposal has "complexity" and "substantial administrative burden."[5] These attempted justifications contradict the substantial evidence in the record and ignore a common-sense reform that would enhance market efficiency and provide clear cost-savings for ratepayers without compromising reliability.

---

[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).

[4] Proposed *Decision Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinement*, Rulemaking (R.) 23-10-011 (May 22, 2025).

[5] PD at 70-71.

To make matters worse, the PD also rejects Energy Division's proposal for a system RA waiver in favor of extending the effective planning reserve margin (PRM) beyond the amount needed to reach a 1-in-10 loss-of-load expectation (LOLE) per Energy Division's analysis. As a result of these deficiencies, the PD fails to provide market participants with the products they need to efficiently and cost-effectively transact under the already-implemented SOD framework *and* fails to provide LSEs with any relief for challenges created by the framework's lack of transactability.

For these reasons, the PD should be modified to adopt hourly load transactability, adopt a system RA waiver, and reject the effective PRM. The PD should also be modified to clarify the intent of the local RA central procurement entity (CPE) data request process and refrain from dictating how RA contracts must specify how the revenues from new California Independent System Operator (CAISO) capacity products must be allocated.

In summary, the Commission should:

- Modify the PD to adopt hourly load obligation trading, a common-sense, cost-saving reform that has been extensively vetted and clearly identified as a market need;
- Modify the PD to adopt a system waiver rather than an effective PRM that unnecessarily exceeds the amount needed to meet a 1-in-10 LOLE;
- Clarify that the intent of the local RA CPE data request is to reduce the CPE requirement based on the aggregated contract data, while maintaining the ability for LSEs to sell to the CPE; and
- Modify the PD to remove the requirement for future RA contracts to specify that imbalance reserve (IR) and reliability capacity (RC) revenues shall be allocated to the LSE as it is unnecessary to prevent double payment.

II. THE PD SHOULD BE MODIFIED TO ADOPT HOURLY LOAD OBLIGATION TRADING, A COMMON-SENSE, COST-SAVING REFORM THAT HAS BEEN EXTENSIVELY VETTED AND CLEARLY IDENTIFIED AS A MARKET NEED

The Commission errs by declining to adopt an hourly load obligation trading mechanism. The PD justifies its rejection of load obligation trading by stating that: (1) it is "premature" to determine that transactability concerns exist under the slice-of-day (SOD) framework;[6] (2) the proposal fails to address "critical issues";[7] and (3) the proposal has "complexity" and "substantial administrative burden."[8] Instead, the PD directs Energy Division to "conduct an evaluation after a full year of SOD implementation to assess the need, benefits, and feasibility of an hourly load obligation trading

6 *Ibid.*
7 *Ibid.*
8 *Id.* at 70.

mechanism," and produce a report on whether transactability issues exist in the second quarter of 2026.[9] As described in sections II.B-II.D below, these claims contradict the substantial evidence in the record supporting an hourly load obligation trading mechanism. The Commission's claims also ignore extensive analysis demonstrating the benefits of hourly load obligation trading, including clear cost-savings for ratepayers without compromising reliability, as described in section II.A.

A. The Commission's Rejection of Hourly Load Obligation Trading Ignore the Common-Sense, Cost-Saving Mechanism that Would Enhance Market Efficiency without Negatively Impacting Reliability

The PD fails to recognize that hourly load obligation trading is a mechanism that can offer significant cost-savings to ratepayers without negatively impacting reliability. CalCCA's extensive analysis of its members' first binding year-ahead showings demonstrates that hourly load trading could improve RA compliance and reduce RA costs by an estimated $180 million per year.[10] Hourly load trading has the potential to provide these affordability benefits while maintaining LSEs' RA obligations and the RA program's reliability targets. The proposal guarantees that: (1) each LSE's obligation to serve its customers, subject to penalties, remains intact; (2) the associated costs of compliance remain with the original LSE; and (3) the Commission can easily validate that all RA requirements continue to be met without overcounting shown resources.[11] By ensuring system RA requirements continue to be fully met either through resource procurement or hourly load obligation trading, the proposal can significantly reduce procurement costs without negative impacts to reliability.[12]

By ignoring these affordability benefits, the PD perpetuates a framework that unnecessarily increases RA costs. The inability to transact at the same granularity as the SOD requirement produces an artificial RA shortage in the market when RA resources may be sufficient, leaving some LSE positions much longer than needed and other LSEs short. This increases both procurement costs and the costs associated with penalties for short LSEs. Given the state's energy affordability crisis, declining to adopt hourly load obligation trading is a missed opportunity to deliver substantial cost savings to ratepayers while achieving reliability.

---

9 *Id.* at 71.

10 *See California Community Choice Association's Proposals on Track 3*, R.23-10-011 (Jan. 17, 2025) (CalCCA Track 3 Proposals), at 8-11.

11 *Id.* at 7-8 and 11-18.

12 *Id.* at 6-11.

B. The PD Errs in Stating that It is Premature to Determine Whether Transactability Concerns Exist Under SOD

It is not premature to conclude that transactability concerns exist under SOD, as noted in the PD. The Commission, stakeholders, and market participants have been concerned with transactability since SOD's inception. D.21-07-014 ordered Energy Division and stakeholders to develop a SOD framework through a series of workshops.[13] The Commission tasked the workshop participants with addressing several key principles, one of which was to "balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity and <u>transactability</u>."[14] Workshop participants emphasized that, if the Commission adopted a framework with hourly requirements, hourly products would also be needed to enable LSEs to transact in a manner that allows them to shape their procurement to their hourly obligations without over-procurement, minimizing costs and mitigating market power.[15] CalCCA summarized this need in its Opening Comments on the *Future of Resource Adequacy Working Group Report* in R.21-10-002, in which CalCCA supported the 24-hour SOD mechanism if hourly transactability was a feature.[16] Despite its direction that transactability should be incorporated into the SOD framework, the Commission declined to adopt hourly transactability following the workshop process. In D.22-06-050, the Commission stated that "…if transactability and inefficiency concerns arise once the new 24-hour framework is implemented, the Commission <u>**may consider proposals to include hourly obligation trading**</u>."[17]

After determining through extensive analysis that such transactability and inefficiency problems indeed do exist, CalCCA therefore proposed hourly load obligation trading again in R.23-10-011 in 2024. CalCCA provided evidence in an extensive analysis of CCA test year showings demonstrating that while CCAs in aggregate were long in September 2024, individual CCAs still had

---

13 *See* Decision (D.) 21-07-014, *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program*, R.19-11-009 (July 15, 2021).

14 D.21-07-014 at 26. (emphasis added)

15 *See Future of Resource Adequacy Working Group Report,* R.21-10-002 (Mar. 1, 2022) at 196-205.

16 *See California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on the Future of Resource Adequacy Working Group Report*, R.21-10-002 (Mar. 24, 2022) at 4-11 ("While CalCCA supports adoption of the 24-hour slice proposal, this support is dependent on the ability of LSEs to trade resources and RA obligations on an hourly basis…without the ability to trade resources and obligations on an hourly basis, the 24-hour proposal could also result in significant unintended consequences that make it unworkable. The Commission must adopt the 24-hour slice proposal with the ability for LSEs to adjust resources and obligations hourly to ensure the new RA framework is transactable, cost-effective, and aligns with the state's policy goals.").

17 D.22-06-050, *Decision Adopting Local Capacity Obligations for 2023 - 2025, Flexible Capacity Obligations for 2023, and Reform Track Framework*, R.21-10-002 (June 24, 2022), at 97 (emphasis added).

short positions.[18] This indicates that additional opportunities to transact between long and short LSEs would increase RA compliance and maintain system RA sufficiency without the need to procure additional resources at high costs. Energy Division's analysis of all LSEs' test year filings demonstrated the same findings when aggregating all LSEs' showings.[19] Despite CalCCA's and Energy Division's evidence demonstrating the need for load obligation trading, however, the Commission in D.24-06-004 again declined to adopt hourly load obligation trading, stating that "[o]nce the SOD framework is implemented, and LSEs' RA showings are binding, the Commission can evaluate whether transactability concerns exist."[20]

The Commission implemented SOD in 2025, and LSEs filed their binding 2025 year-ahead showings in October 2024. In Track 3, CalCCA again demonstrated that load obligation trading is necessary as the binding 2025 year-ahead showings show that individual LSEs faced deficiencies despite the system being reliable in aggregate.[21] Energy Division's analysis of all LSEs' binding 2025 year-ahead showings confirmed these findings.[22] CalCCA also expanded its analysis to evaluate the cost-savings that could be realized by adopting hourly load obligation trading. As described in section II.A., this analysis found that allowing LSEs to transact load obligations hourly can reduce overall RA costs by an estimated $180 million per year.[23]

Transactability concerns from SOD have been raised by stakeholders and market participants since 2021, and substantial evidence demonstrates that load obligation trading will alleviate those concerns. Extensive analysis from test year and binding showings corroborates the transactability problems. In both the test year and the first binding year, the analysis from CalCCA and Energy Division demonstrates that although system reliability needs are fully satisfied in aggregate, the Commission will still issue penalties to individual LSEs – signaling a transactability problem with the SOD framework. A broad range of stakeholders support hourly load obligation trading in Track 3,

---

18 *Public Version - California Community Choice Association's Comments on Assigned Commissioner's Scoping Memo and Ruling*, R.23-10-011 (Jan. 19, 2024), at 22-27.

19 *Report on Resource Adequacy Slice of Day Implementation and Year Ahead Showings*, R.23-10-011 (Feb. 5, 2024), at 42.

20 D.24-06-004, *Decision Adopting Local Capacity Obligations for 2025-2027, Flexible Capacity Obligations for 2025, and Program Refinements*, R.23-10-011 (June 20, 2024), at 73.

21 CalCCA Track 3 Proposals, at 3-15.

22 *Workshop on Track 3 Proposals in R.23-10-011*, R.23-10-011 (Feb. 12, 2025) (Track 3 WS), at 71-76.

23 CalCCA Track 3 Proposals, at 8-11.

including LSEs, suppliers, ratepayer advocates, and environmental groups.[24] The market has therefore identified a logical and cost-effective solution to these transactability problems, but the PD is blocking its implementation.

C. The PD Errs by Finding the Proposal Fails to Fully Address Critical Issues

The PD states, "[t]he Commission also agrees with parties that state that the proposal *fails to fully address critical issues*, such as whether CalCCA's concerns could be addressed through **existing trading mechanisms**, what types of **guardrails** should be added to limit the use of hourly trading, and how the **RA penalty regime** will interact with the proposal."[25] This statement is factually incorrect because:

- First, CalCCA addressed the shortcomings of the **existing trading mechanisms** in its January 17, 2025, Track 3 Proposal:

  > "While it may be technically feasible for all LSEs to meet their SOD requirements relying only on swaps (*i.e.,* LSEs trading resources at the monthly level rather than hourly), there is significant difficulty in getting all the necessary transactions to line up to meet reliability through a bilateral market design. It is more likely that multiple transactions between multiple LSEs will be necessary to achieve compliance through swaps. While swaps and full resources procurement should be an option, they should not be the only options. A properly constructed load obligation trade will allow for the grid to be reliably maintained while buyers and sellers determine among themselves the value of the load obligation."[26]

- Second, CalCCA added a **guardrail** to its proposal by including a 25 percent limit on the amount of load an LSE can trade in its March 3, 2025, Opening Comments, directly in response to concerns expressed by Energy Division and PG&E:

  > "If the Commission has concerns about LSEs trading away their entire obligation or that the quantity of trades may be administratively burdensome for Energy Division, the Commission can set an initial trading limit of no more than 25 percent of an LSE's compliance obligation…In the February 12, 2025, workshop, Energy Division and Pacific Gas and Electric Company (PG&E) expressed concern over the

---

[24] *See* Opening Comments filed in R.23-10-011 on or about March 3, 2025: *American Clean Power – California Opening Comments,* at 15; *Alliance for Retail Energy Markets Opening Comments,* at 3; *The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) Opening Comments,* at 10-11; *Clean Energy Buyers Association Opening Comments,* at 7; *Center for Energy Efficiency and Renewable Technologies Opening Comments,* at 3; *California Environmental Justice Alliance Opening Comments,* at 11-12; *Hydrostor, Inc. Opening Comments,* at 9; *Microsoft Corporation Opening Comments,* at 12-13; and *Shell Energy North America (US), L.P. Opening Comments,* at 4-5.

[25] PD at 71 (emphasis added).

[26] CalCCA Track 3 Proposals, at 7.

lack of a limit in CalCCA's proposal. If the Commission allows hourly load obligation trading, but determines such a limit is necessary, the Commission should adopt a limit of 25 percent of the LSE's compliance obligation. Given this limit may prohibit the use of hourly load obligation trading by smaller LSEs, however, the Commission should also adopt a de minimis threshold allowing LSEs with RA requirements less than 200 MW to trade up to 50 MW of their obligation. Furthermore, if the Commission is concerned with the administrative burden of multiple layers of load obligation trades, the Commission can require that if an LSE purchases a load obligation trade and then sells it to another LSE, that sale will count towards that LSE's 25 percent limit."[27]

- CalCCA addressed the **penalty regime** in its March 17, 2025, Reply Comments:

> "Load obligation trading is simply another product that can be used to meet compliance obligations. It has no impact on the current penalty mechanism. If an entity uses a load obligation trade and is compliant, the entity will not receive a penalty, will not accumulate any points, and will not be prohibited from expansion. If the entity participated in load obligation trades and the combination of those trades and resource procurement did not meet their obligation, then they would be penalized as they are today (including financial penalties, points accumulation, and expansion prohibitions) based upon the hour with the largest deficiency."[28]

CalCCA has already repeatedly addressed, and even refined its load obligation trading proposal in response to, the "critical issues" identified in the PD. To state otherwise is in error.

D. The PD Errs in Overstating the Complexity and Administrative Burden of Hourly Load Obligation Trading

The PD errs in stating hourly load obligation trading would "add both complexity to the new SOD framework and substantial administrative burden on Energy Division Staff to track transactions and verify compliance."[29] CalCCA demonstrated in its Track 3 Proposals,[30] at the Track 3 workshop,[31] and with Energy Division individually that minor updates to the existing LSE SOD showing tool, which is used by LSEs to make their year-ahead and month-ahead RA compliance showings, can accommodate load obligation trading. These minor updates will therefore allow hourly

---

27 *California Community Choice Association's Opening Comments on the Assigned Commissioner's Amended Scoping Memo and Ruling*, R.23-10-011 (Mar. 3, 2025) (CalCCA Amended Scoping Memo Opening Comments), at 10-11.

28 *California Community Choice Association's Reply Comments on the Assigned Commissioner's Amended Scoping Memo and Ruling*, R.23-10-011 (Mar. 17, 2025), at 6.

29 PD at 70.

30 CalCCA Track 3 Proposals at 11-17.

31 Track 3 WS at 92-102.

load obligation trading to be documented by LSEs and validated by Energy Division using the existing tools.

The showing and validation process for hourly load obligation trading is very similar to the existing process the Commission uses to validate RA showings by matching them with generator supply plans. If Energy Division cannot make minor updates to its showing and validation tools to support functionality that would provide significant transactability and cost-saving benefits, it calls into question whether the Commission was ready to implement SOD in the first place. For these reasons, the Commission should modify the PD to adopt hourly load obligation trading.

E. At Minimum, the Commission Should Commit to Implementing Hourly Load Obligation Trading for RA-Year 2027

While the PD errs by overstating the administrative burden and complexity of implementing hourly load obligation trading, if the Commission or Energy Division continue to have serious concerns about the ability to implement hourly load obligation trading for the 2026 RA year, the Commission should commit to implementing hourly load obligation trading for the 2027 RA year. Energy Division and stakeholders could then spend the rest of 2025 and 2026 implementing the tools and validation processes necessary to have hourly load obligation trading implemented for the 2027 RA year. The Commission should modify the PD to adopt hourly load obligation trading for RA year 2027 at the latest, if there are concerns about the ability to implement it for 2026.

III. THE COMMISSION SHOULD MODIFY THE PD TO ADOPT A SYSTEM WAIVER RATHER THAN AN EFFECTIVE PRM THAT EXCEEDS THE AMOUNT NEEDED TO MEET A 1-IN-10 LOLE

The PD should be modified to adopt a system RA waiver rather than an effective PRM. Although Energy Division acknowledges tight market conditions,[32] the PD denies any form of waiver even when the potential for market power exists. Instead, the PD places LSEs trying to comply with their RA obligations in competition with IOUs procuring to an effective PRM for which the IOUs face no penalty and can cherry-pick which capacity to allocate to all LSEs versus which capacity they retain for their own RA needs. By extending the effective PRM, the PD creates a market dynamic that is unreasonable, costly, and inequitable among LSE buyers. In addition, the PD exposes customers to significant costs by setting the total level of procurement above the amount Energy Division found to be necessary to meet a 1-in-10 LOLE in its modeling. At a critical time for both market scarcity and

---

[32] *Administrative Law Judge's Ruling on Energy Division's Track 3 Proposals and Joint Staff Qualifying Capacity Proposal Status Update*, R.23-10-011 (Jan. 21, 2025) (Jan. 21 Ruling), at Attachment 2, 11.

customer affordability, the Commission should therefore modify the PD to: (1) adopt a PRM aligned with the modeling in the record; and (2) afford LSEs the opportunity to procure to that PRM themselves, with the ability to request a waiver if despite reasonable commercial practice, market conditions prevent them from obtaining sufficient resources.

A. The Commission Should Modify the PD to Ensure the Total PRM Does Not Exceed the PRM Found in Energy Division's LOLE Study and Adopt a System RA Waiver Rather than an Effective PRM

The PD should be modified to set the PRM at a level that is aligned with Energy Division's LOLE modeling. The PD adopts a 3-5.5 percent effective PRM combined with an 18 percent PRM.[33] This would raise the amount of RA procurement well above the level needed to achieve a 1-in-10 LOLE based upon Energy Division's study.[34] Energy Division's study states that to achieve a 1-in-10 LOLE, the PRM must be 21 percent for summer months and 20 percent for non-summer months. [35] An 18 percent PRM plus the a 3-5.5 percent effective PRM would result in a total PRM between 21 to 23.5 percent for the summer months. This level of PRM is not necessary to achieve the 1-in-10 LOLE standard as modeled and will force demand for a scarce product in the summer months, driving prices higher for Californians.

The PD justifies this by stating:

> As we stated in D.23-06-029 when adopting the 17% PRM and effective PRM:
>
> Extending the effective PRM is beneficial in that it provides non-binding targets for IOUs to procure contingency resources, including resources that are not subject to strict RA counting rules and resources that fewer entities are competing for, such as imports procured after the RA showing date and firm energy from co-generation facilities. This allows procurement of resources that provide reliability benefits without unnecessarily inflating RA prices and costs to ratepayers, and without reducing the pool of available RA resources.
>
> We affirm our rationale from D.23-06-029 that extending the effective PRM would allow for the procurement of resources that provide reliability benefits, without unnecessarily inflating prices and costs to ratepayers and without reducing the pool of available RA resources. As mandated by

---

33 PD at 32-33.

34 *Administrative Law Judge's Ruling on Energy Division's Hour Offset Workshop Slides and Load Migration Update*, R.23-10-011 (Feb. 25, 2025), at Attachment 2.

35 *Ibid.*

> Pub. Util. Code 380, the RA program must be designed to maintain reliability of electrical service while also minimizing costs to ratepayers.[36]

The Commission relies incorrectly on the potential for the effective PRM to be procured from resources that are not RA eligible. Historically, the IOUs have used RA eligible resources to meet the effective PRM. For example, in its 2024 Excess Resource Report, San Diego Gas & Electric Company (SDGE) lists supply-side resources for the effective PRM totaling between 128 and 136 megawatts (MW) between June and October.[37] As reference, SDG&E provides AL-3689, Resolution E-5219, and excess resources from the IOU's portfolio. AL-3689 asked for permission to enter into an RA purchase agreement. Resolution E-5219 authorized new resources, which provided, among other things, RA capacity. In total, all the resources SDG&E used to meet the effective PRM came from RA-eligible resources that other LSEs could have used to meet their RA requirements.

Similarly, in 2024, Southern California Edison Company (SCE) reported between 194 and 1,195 MW of Tolls and RA-only procurement to meet the effective PRM for June through October.[38] Each of these qualify as RA eligible resources. The non-RA resources shown by SCE were significantly smaller with only 100 MW of "as available"[39] capacity for July through October. SCE then shows non-RA transactions that only covered a handful of days with seven days of daily imports between 100 and 150 MW in July and three days of daily imports of 100 MW in September. The result is that the vast majority of SCE's effective PRM procurement came from RA eligible resources that other LSEs needed for compliance.

Finally, in 2024, Pacific Gas and Electric Company (PG&E) reported a staggering 150 to 802 MW of excess resources in their portfolio that were used to meet the effective PRM for June through October.[40] In addition, PG&E procured 20 MW of utility-owned generation (UOG) enhancement. Both of these categories of resources, excess resources and UOG enhancements, are from RA-eligible resources. PG&E only procured 44 MW of non-RA eligible resources through energy-only call options in June through October. In other words, the vast majority of PG&E's procurement came from RA-eligible resources that other LSEs could have used to meet their compliance obligations but were instead used to meet an effective PRM.

---

36 PD at 30.
37 *See* SDG&E Excess Resource Report for 2024.
38 *See* SCE Excess Resource Report for 2024.
39 Assumed to be resources that would provide energy only if the energy were available which would not qualify for RA.
40 *See* PG&E Excess Resource Report for 2024.

At the same time, RA prices were very high in the summer of 2024. The IOUs' procurement of RA eligible resources for the effective PRM and the historically high prices experienced in the summer of 2024 therefore challenge the PD's conclusion that "extending the effective PRM would allow for the procurement of resources that provide reliability benefits, without unnecessarily inflating prices and costs to ratepayers and without reducing the pool of available RA resources."[41]

In addition, while the Commission does not want to rely on CAISO backstop procurement, using an effective PRM creates a reliability risk by eliminating the potential for CAISO backstop if the IOUs fail to procure the effective PRM. The CAISO tariff only allows it to procure backstop capacity for RA requirement deficiencies, significant events, or exceptional dispatches.[42] Since the effective PRM is not part of the RA requirement and does not qualify as a significant event or exceptional dispatch, any failure to procure to the effective PRM will not be backstopped by the CAISO.

To address these significant concerns with the effective PRM and as discussed below, the Commission should modify the PD to implement a waiver process to address the potential for the exercise of market power, as has been used for the local RA program. If, nonetheless, the Commission retains the effective PRM, it should modify the PD in two ways. First, the Commission should not set the effective PRM in combination with the PRM for all LSEs above the level of total PRM Energy Division determined will meet a 1-in-10 LOLE, which is 21 percent in the summer months. This would mean that the effective PRM should be limited to no more than three percent with an 18 percent PRM for all LSEs. Second, the Commission should place guardrails on contracts used to meet the effective PRM to mitigate potential cost shifts. Specifically, the Commission should require that existing IOU capacity contracts used for the effective PRM must be kept out of IOU bundled portfolios for the lesser of a full year strip or the length of the fixed price terms. Otherwise, the IOUs can choose resources from their existing portfolio—that have static prices for a term length that do not represent peak summer RA prices—use them for specific effective PRM summer months with significantly higher prices and spread the artificially high contract costs among all LSEs.

B. The Commission Should Implement a Waiver Process as an Effective Market Power Mitigation Tool

The Commission should modify the PD to adopt a system RA waiver process. While the PD rejects SCE's study that the PRM does not need to be higher than 15.5 percent to achieve a 1 in 10

41 PD at 30.

42 See CAISO Tariff Section 43A.2.

LOLE,[43] the PD does not reject Cal Advocates assertion that market power could be exerted at levels below 17 percent.[44] A waiver process is the best way to align reliability and affordability at a time when affordability is a significant challenge.

The Commission rejects a waiver based on three assertions that the system waiver process:

> (1) raises fairness concerns in that deficient LSEs may lean on LSEs that procure sufficient RA capacity, (2) adds administrative burden on Energy Division's resources to process waivers, particularly if a large number of LSEs submit waivers, and (3) increases the need to rely on the CAISO's backstop mechanism if sufficient RA capacity is not procured by LSEs.[45]

The Commission errs in each of these statements. First, Energy Division's proposal addresses fairness and leaning concerns in several ways. Energy Division's proposal for a system waiver never implied that a waiver was guaranteed. The LSE would need to demonstrate that it took reasonable commercial actions and that despite its reasonable efforts, the LSE could not obtain sufficient RA at prices at or below a level that Energy Division staff provided as indicating competitive offers.[46] The waiver process therefore addresses fairness concerns by requiring LSEs to take reasonable actions, providing all LSEs the ability to be considered for the same treatment, and allocating CAISO backstop costs to the deficient LSE. These conditions do not support leaning. Instead, they support developing a competitive marketplace where Californians are not expected to pay any price but are expected to pay a FERC regulated backstop price intended to prevent market power.

Second, while CalCCA acknowledges that the implementation of a waiver process could create additional administrative burden, this additional burden is outweighed by mitigating run-away RA prices that exceed the going forward fixed costs of the resources (*i.e.,* the FERC authorized backstop payment for the CAISO) *and* the cost of new entry. Californians should not be required to pay an unlimited, unjustifiable price for RA. In addition, CalCCA proposed a rebuttable presumption process for approving waivers to minimize additional administrative burden created by a waiver process.[47]

Third, over its history, the CAISO has infrequently used its CPM authority to backstop RA. Since 2019, the CAISO has backstopped for local reliability in May and July of 2019 for a total of 201.78 MW-months, and once in September of 2020 for 15.73 MW-months. The CAISO also

---

43 *See* PD at 28.

44 *See Comments of the Public Advocates Office on Track 3 Proposals*, R.23-10-011 (Mar. 3, 2025), at 6-7.

45 PD at 28.

46 Jan. 21 Ruling, at Attachment 2, 15-18.

47 *See* CalCCA Amended Scoping Memo Opening Comments, at 3-8.

procured 19 MW-months of backstop capacity in 2022 and 70 MW-months in 2023 for potential thermal overloads. Finally, in 2020 and 2021, the CAISO performed backstop procurement for the summer months due to "extreme weather and under forecast of load." The most significant procurement occurred in 2021 totaling 1,722 MW-months.[48] This history is not reflective of an over-reliance on CAISO backstop. Indeed, the RA program has effectively managed reliability without the need for backstop. Having a limited time of market scarcity and prices that may be influenced by market power is not a reason to conclude that the Commission would over-rely on CAISO backstop. Now is the time to bring the market under control so that competition can resume, bringing reliability at affordable rates without using backstop mechanisms. For these reasons, the Commission should adopt the waiver process proposed by Energy Division staff for any procurement over 15.5 percent as initially proposed by CalCCA.

IV. THE COMMISSION SHOULD CLARIFY THAT THE INTENT OF THE LOCAL RA CPE DATA REQUEST IS TO REDUCE THE CPE REQUIREMENT BASED ON THE AGGREGATED CONTRACT DATA, WHILE MAINTAINING THE ABILITY FOR LSES TO SELL TO THE CPE

The Commission errs by failing to provide the clarity necessary to make the local RA CPE data request useful in informing CPE procurement efforts. In the PD, the Commission reiterates what it stated in D.24-12-003. That is:

> …the Commission is not directing the CPEs to reduce the CPE requirement based on the aggregated data provided by Energy Division as to what local resources have been contracted by LSEs. Reducing the CPE's requirement in this manner would result in LSEs being unable to compete in the annual solicitation process, as those resources would have reduced the CPE's local requirement.[49]

CalCCA supports the Commission's objective of retaining LSEs' ability to compete in the CPE's annual solicitation process. However, if the information collected in the data request is not used to reduce the CPE requirement, it is not clear what benefit having the information provides. While the PD states the information will be used to "better assess the actual needs for short-term and long-term procurement for the three-year forward requirements and beyond,"[50] the inability for the CPE to adjust procurement targets because of this data appears to obviate the benefits of having the information.

---

48 *See* https://www.caiso.com/library/capacity-procurement-mechanism-reports.

49 PD at 78.

50 *Ibid.*

To ensure LSEs can continue to participate in CPE solicitations *and* to ensure the information collected via local RA CPE data request informs CPE procurement activity, the Commission should modify the PD in two ways. First, the PD should clarify that the intent of the local RA CPE data request is to reduce the CPE requirement based on the aggregated contract data. Second, these modifications should include a process that maintains the ability for LSEs to sell to the CPE. The ability for LSEs to sell to the CPE could be maintained by not automatically reducing the CPE's local obligation by all resources contained in the data request, but instead asking LSEs in its data request which local RA capacity under contract they plan to offer to the CPE. The Commission could then only reduce the CPE's procurement target by the amount of local capacity LSEs do not already plan to offer to the CPE. These modifications will ensure the PD provides the clarity necessary to make the local RA CPE data request useful while retaining LSEs' ability to offer into CPE solicitations.

V. THE COMMISSION SHOULD MODIFY THE PD TO REMOVE THE REQUIREMENT FOR FUTURE RA CONTRACTS TO SPECIFY THAT IMBALANCE RESERVE AND RELIABILITY CAPACITY REVENUES SHALL BE ALLOCATED TO THE LSE

The PD errs by requiring specification in RA contracts executed after adoption of the PD that any CAISO revenues for IR or RC products shall be credited back to the LSE. The current CAISO tariff requires RA resources to bid zero dollars into the residual unit commitment (RUC) process and prohibits them from receiving RUC market revenues. Once the CAISO implements its Day-Ahead Market Enhancements (DAME) and Extended Day-Ahead Market (EDAM) initiatives, the CAISO will no longer require RA resources to bid zero dollars into RUC and will allow them to receive revenues for IR and RC products. The PD similarly removes the requirement for RA resources to bid zero dollars for IR and RC products upon EDAM and DAME implementation and will allow RA resources to be eligible for IR and RC revenues.[51] CalCCA supports the PD in this regard, as it will ensure LSEs participating in the Commission's RA program do not subsidize other LSEs in EDAM by providing most of the RUC capacity due to the zero-dollar bidding requirement.

The PD also states, however, that:

> [w]hen the [CAISO] begins the operation of the [EDAM], Commission-jurisdictional [LSEs] with existing [RA] contracts will make a good faith effort to ensure revenues from Imbalance Reserves, Reliability Capacity Up (RCU), or Reliability Capacity Down (RCD) products are credited back to the LSE that has procured the RA capacity value of these resources. For contracts executed after the issuance of this decision, the

[51] PD, Ordering Paragraph (O¶) 16.

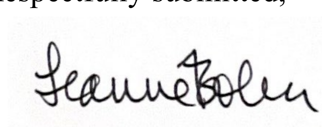
> contracting LSE shall specify in the RA contract that any CAISO revenues for Imbalance Reserves, RCU, or RCD products shall be credited back to the LSE that has procured the RA capacity value of the resource.[52]

The Commission should not require specification in the RA contracts that any CAISO revenues for IR or RC products shall be credited back to the LSE. The treatment of IR and RC revenues should be left to the counterparties to negotiate in their own contract terms, because there are multiple ways to do so. LSEs and suppliers can agree to use the CAISO's DAME Transitional Measures outlined in the CAISO's EDAM and DAME tariff language, which will be in place for three years. Alternatively, counterparties can establish other contract terms to account for these new revenue sources which could include discounting the RA capacity price for anticipated IR and RC revenues. How counterparties choose to treat IR and RC revenues will be dependent on the counterparties and their contract negotiation. The Commission should therefore modify the PD to *not* specify RA contracting requirements related to IR and RC revenue allocation. Since the potential for double payment is an economic issue and not a reliability issue, the Commission should leave LSEs the option to best protect their customers. If the Commission believes for the IOUs that the potential for double payment cannot be effectively mitigated by allowing the IOU flexibility, the Commission can order the IOUs to address the issue in a specific manner.

VI. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and requests adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the PD as provided in Appendix A, attached hereto.

Respectfully submitted,



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

June 11, 2025

---

52 *Id.,* O¶ 17.

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE PROPOSED DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2026-2028, FLEXIBLE CAPACITY OBLIGATIONS FOR 2026, AND PROGRAM REFINEMENTS

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

Proposed text deletions show as ~~**bold and strikethrough**~~
Proposed text additions show as **<u>bold and underlined</u>**

FINDINGS OF FACT

4. Increasing the PRM to ~~**18%**~~ **<u>21%</u>** **<u>and adopting a system RA waiver process in which LSEs must demonstrate reasonable commercial efforts for procurement above 15.5% best balances reliability and affordability while implementing an effective market power mitigation tool.</u>** ~~**extending the effective PRM target for the 2026 and 2027 RA years would achieve several benefits: (1) it would increase the PRM above its current level, as has been demonstrated as needed by Energy Division's LOLE studies; (2) it would move in the direction of transferring additional procurement responsibilities to LSEs; and (3) it would provide more time to review the need for additional increases to the PRM once the SOD framework is better established and modeling capabilities and input processes have further matured.**~~

~~**5. We affirm our rationale from D.23-06-029 that extending the effective PRM would allow for the procurement of resources that provide reliability benefits, without unnecessarily inflating prices and costs to ratepayers and without reducing the pool of available RA resources.**~~

6. A **<u>21% PRM with a system RA waiver for procurement above 15.5% if LSEs demonstrate commercially reasonable efforts to procure</u>** ~~**18% PRM and an extension of the effective PRM target for June-October for the 2026 and 2027 RA years**~~ is a reasonable and prudent approach that helps ensure grid reliability by increasing the PRM as indicated by the LOLE studies, while minimizing costs to ratepayers.

10. ~~**It is premature to determine that**~~ **<u>T</u>**ransactability concerns exist under the SOD framework and ~~that~~ there is a need for an hourly load obligation trading proposal. ~~**CalCCA's proposal fails to fully address critical issues, such as whether concerns could be addressed through existing trading mechanisms, what types of guardrails should be added to limit the use of hourly trading, and how the RA penalty regime will interact with the mechanism.**~~

CONCLUSIONS OF LAW

4. A ~~**18%**~~ **<u>21%</u>** PRM with **<u>a system RA waiver for procurement above 15.5% if LSEs demonstrate commercially reasonable efforts should be adopted.</u>**~~**an extension of the effective PRM target for June-October should be adopted for the 2026 and 2027 RA years.**~~

8. The Commission should authorize Energy Division to **implement hourly load obligation trading as soon as possible.** ~~prepare a report in Q2 2026 on whether transactability issues exist~~.

ORDERING PARAGRAPHS

6. For the 2026 and 2027 Resource Adequacy (RA) compliance years, a ~~18%~~ **21%** planning reserve margin (PRM), and **a system RA waiver for procurement above 15.5% if LSEs demonstrate commercially reasonable efforts to procure is adopted.** ~~**an extension of the effective PRM procurement target of 1,260-2,300 megawatts (MW) for June-October, is adopted. The procurement target will be divided between the three investor-owned utilities as follows: 120-220 MW San Diego Gas & Electric Company, and 570- 1,040 MW each for Pacific Gas and Electric Company and Southern California Edison Company. The requirements adopted in Decision 23-06-029 pertaining to the effective planning reserve margin are applicable to the effective PRM adopted in this decision.**~~

~~**11. Energy Division is authorized to conduct an evaluation after a full year of Slice of Day implementation to assess the need, benefits, and feasibility of an hourly load obligation trading mechanism. Energy Division is authorized to prepare a report in the 2nd Quarter of 2026 on whether transactability issues exist.**~~

~~**17. When the California Independent System Operator (CAISO) begins the operation of the Extended Day-Ahead Market (EDAM), Commission-jurisdictional load-serving entities (LSE) with existing Resource Adequacy (RA) contracts will make a good faith effort to ensure revenues from Imbalance Reserves, Reliability Capacity Up (RCU), or Reliability Capacity Down (RCD) products are credited back to the LSE that has procured the RA capacity value of these resources. For contracts executed after the issuance of this decision, the contracting LSE shall specify in the RA contract that any CAISO revenues for Imbalance Reserves, RCU, or RCD products shall be credited back to the LSE that has procured the RA capacity value of the resource.**~~

New Order 1: CalCCA's hourly load obligation trading is adopted. Energy Division is authorized to implement hourly load obligation trading as soon as possible but no later than for RA year 2027.

New Order 2: In addition to the data collected pursuant to D.24-12-003 Ordering Paragraph 4, Energy Division shall collect information from load serving entities that specifies which local RA capacity under contract the LSEs plan to offer to the CPE.

New Order 3: Energy Division shall use the information collected in [New Order 2] to adjust the local resource adequacy central procurement entities' (CPEs') procurement targets by the amount of local capacity under contract that load serving entities do not plan to offer to the CPE.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION

Evelyn Kahl
General Counsel and Chief Policy Officer
Leanne Bober
Director of Regulatory Affairs
and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9815
E-mail: regulatory@cal-cca.org

Tim Lindl
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (510) 314-8385
E-mail: tlindl@keyesfox.com

On behalf of
California Community Choice Association

June 12, 2025

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Cases

Statutes

California Public Utilities Commission Decisions

California Public Utilities Commission Proceedings

SUMMARY OF RECOMMENDATIONS

The California Community Choice Association (CalCCA) recommends that the California Public Utilities Commission (Commission):

- Adopt the proposed *Decision Adopting Changes to The Calculation of The Resource Adequacy Market Price Benchmark's*[1] (Proposed Decision or PD) affirmation of D.18-10-019's mark-to-market methodology;
- To the extent it decides to must move forward to address its identified "flaws" in the Resource Adequacy (RA) Market Price Benchmark (MPB):
  - Ensure ratepayers and stakeholders can calculate the PD's true impacts by providing the RA MPBs, and the data underlying those MPBs, using the PD's proposed methodology;
  - Adopt the PD's combination of the RA MPBs into one MPB to address the volume problems identified in the Staff Proposal;
  - If the Commission decides it must modify the timeframe of transactions, modify the four-year timeframe in the PD and instead implement the Direct Access Customer Coalition (DACC)/Alliance for Retail Energy Markets (AReM) proposal of a 21-month data window for the forecast and a 33-month data window for the final RA MPB;
- Remove the PD's requirement to use the new RA MPB to calculate the Final 2025 RA benchmark which would constitute unlawful retroactive ratemaking; and
- Clarify in the Conclusions of Law (COLs) that the PD's new methodology, if adopted, will apply in future years until a new methodology is adopted.

---

[1] Rulemaking (R.) 25-02-005, *Decision Adopting Changes to the Calculation of the Resource Adequacy Market Price Benchmark* (May 23, 2025).

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION

CalCCA[2] submits these comments pursuant to Rule 14.3 of the Commission Rules of Practice and Procedure[3] on the Proposed Decision, mailed May 23, 2025.

I. INTRODUCTION

The PD cuts through the noise of calls for immediate reform of the RA MPB to protect bundled customers from high 2025 RA market prices, affirming the mark-to-market paradigm adopted in D.18-10-019. A mark-to-market methodology requires establishing the *value* of the investor-owned utility (IOU) Power Charge Indifference Adjustment (PCIA) portfolio conveyed to unbundled customers, pursuant to Public Utilities Code section 366.2(g), based on what that portfolio can be bought and sold for in the *present market*. With the mark-to-market paradigm set, two questions remain: (1) does *any* change need to be made to the RA MPB?; and (2) if it does, then *what* change can be made that still preserves the current paradigm? The PD attempts to "strike a balance between the need to adjust the flaws in our present approach and preserv[e] the mark-to-market paradigm," by: (1) collapsing the Local, System, and Flex RA MPBs into one MPB; (2) expanding the timeframe of transactions used to calculate the RA MPB to match the Local RA MPB of three years for the forecast, and four years for the

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).

final;[4] and (3) removing non-market based transactions from the calculation, including affiliate, swap, and duplicative sleeve transactions.

The PD leapfrogs the question of whether any change to the RA MPB needs to be made. The PD focuses on the decline in the number of transactions used to form the RA MPB, determining that a broader range of transactions is necessary. The problem with this thinking, however, is that the PD neither determines what transaction volume is needed to ensure a robust benchmark nor whether the reduced transaction volume has produced an inaccurate value. Indeed, the precipitous drop in RA market prices since their highs in late Summer 2025 has made clear that those prices—and the resulting escalated Forecast 2025 RA MPBs—are short-term price spikes likely resulting from scarcity tied to the Commission's implementation of a new Slice-of-Day (SOD) framework for RA. These short-term spikes do not warrant skirting the policymaking and evidentiary standards to which the Commission holds itself to aggressively expand the RA MPB transaction dataset as proposed in the Energy Division (ED) Staff Report. The expedited schedule in this highly contested and high-stakes proceeding – one which has the potential to shift hundreds of millions in costs to CCA customers -- has led to "black box" policymaking using data parties have been unable to review and failing to make public the extent of rate impacts on those customers. In short, substantial evidence does not publicly exist to prove that the current RA MPB methodology is not working as it should, reflecting the ups and downs of the RA market. The current methodology, designed to reflect *current market prices*, should not be abruptly modified to temper a short-term price spike to benefit bundled customers. This results-based policymaking is troubling and begs the question of whether affordability for *all* California ratepayers, or only for bundled ratepayers, is the priority of the Commission.

If the Commission decides it must move forward with modifying the RA MPB, it has more work to do. It must first provide adequate data to support its findings in the PD and to allow stakeholders to quantify the PD's impacts. The Commission must also prove that the "balance" struck by the PD to "adjust the flaws" identified in the Staff Report truly maintains the integrity of the mark-to-market approach. The first change, to combine the Local, System, and Flex MPBs into one, likely is enough to provide a representative sample of the current market and address the volume problems identified in the Staff Proposal. However, the PD goes further, expanding the transaction timeframe to calculate the RA

---

4 The Proposed Decision inaccurately states the current Local RA MPB timeframe, which is actually 33 months for the forecast, and 45 months for the final MPBs. *See* D.19-10-001, Attachment A.

MPB to a four-year timeframe consistent with the Local RA timeframe.[5] While this timeframe is slightly shorter than the five years proposed by ED and the IOUs, it fails to strike an adequate "balance" given that the core principle of the mark-to-market paradigm is the valuation of something based on what its value is in the open market *today.* In other words, the farther the Commission moves away from what capacity can be bought or sold for today, the less accurate its valuation, and the less likely the final decision will convey to departed customers the present *value* of the IOUs' generation portfolios.

Another of the PD's justifications for choosing the four-year Local RA timeframe is that it "provide[s] a more accurate reflection of RA market costs" and "eliminates the arbitrary slicing of the market"[6] by preventing removal of any Local RA transactions from the calculation.[7] However, if the data set used to calculate the RA MPB is intended to be based on the mark-to-market methodology, even the PD recognizes that it must "reflect the market value driving the transaction."[8] Local RA, of the three categories of RA, is by far the least market-relevant attribute given that in PG&E and SCE service territories Local RA is purchased by a CPE on behalf of all LSEs. Therefore, the Local RA timeframe should not determine the timeframe to find the "balance" the PD seeks.

The PD's affirmation of the D.18-10-019 RA MPB methodology should be adopted. If the Commission moves forward with changes to the RA MPB, however, the four-year timeframe fails to represent the mark-to-market methodology. Instead, if the Commission is determined to expand the timeframe, CalCCA continues to support the proposal advanced by DACC/AReM – eligible transactions executed in year (n-2) and Q1-3 of year (n-1) for delivery in year n for the forecast (i.e., 21 months), with additional true-up data added for year n (33 months for the true-up).[9] DACC/AReM's proposal more accurately reflects the mark-to-market methodology, and strikes the "balance" the Commission seeks.

The PD should also be modified to avoid unlawful retroactive ratemaking by striking the requirement to apply the new methodology to the 2025 true-up. The PD justifies retroactive application by concluding that changes to the PCIA methodology are not "general ratemaking," a conclusion that

---

5 Under the PD's proposal, the forecast RA MPB is based on three years of transaction data, and the final MPB is based on four years of transaction data. PD, COL 2, at 30.

6 *Id.* at 18.

7 *Ibid.*

8 *Id.* at 22.

9 *See Opening Brief of the Direct Access Customer Coalition and Alliance for Retail Energy Markets*, R.25-02-005 (Apr. 21, 2025) (DACC/AReM Opening Brief), at 12; *California Community Choice Association's Reply Brief*, R.25-02-005 (Apr. 30, 2025), at 14.

misreads and misapplies the law. If changes to the PCIA are not "general ratemaking," there is no boundary on the retroactive effect of any future changes to the PCIA methodology, a result that undermines ratepayer confidence in the finality of the Commission's rates. If the Commission again uses mercurial notions of indifference to justify changes to the PCIA, what trust can ratepayers have that they will not be back-charged for *years or decades* of purportedly unjust and unreasonable rates? Compounding this legal error, the PD appears to conclude it can read two conflicting statutes by applying one (preventing costs shifts) while simultaneously ignoring the other (prohibiting retroactive ratemaking); but the law says otherwise.

Finally, the Commission should include in the COLs language in its final decision stating that its new MPB should be applied in future years, *i.e.*, until a new methodology is approved. Without that clarification, the COL could be read to only apply the new methodology once in the upcoming calculations. A one-time application, recognizing that the shift in this methodology will increase RA MPBs in our current declining price environment, would result in blatant "cherry-picking" of methodologies in favor of bundled customers.

In light of the above, CalCCA recommends that the Commission:

- Adopt the PD's affirmation of D.18-10-019's mark-to-market methodology;
- To the extent the Commission decides it must move forward to address its identified "flaws" in the RA MPB, it should:
    - Ensure ratepayers and stakeholders can calculate the PD's true impacts by providing the RA MPBs, and the data underlying those MPBs, using the PD's proposed methodology;
    - Adopt the PD's combination of the RA MPBs into one MPB to address the volume problems identified in the Staff Proposal;
    - If the Commission decides it must modify the timeframe of transactions, modify the four-year timeframe in the PD and instead implement the DACC/AReM proposal of a 21-month data window for the forecast and a 33month data window for the final RA MPB;
- Remove the PD's requirement to use the new RA MPB to calculate the Final 2025 RA benchmark, which would constitute unlawful retroactive ratemaking; and
- Clarify in the COLs that the PD's new methodology, if adopted, will apply in future years until a new methodology is adopted.

II. THE PD MAKES SIGNIFICANT CHANGES TO THE RA MPB WHILE KEEPING PARTIES IN THE DARK AS TO THE IMPACTS OF THOSE CHANGES

In dramatic contrast to the Commission's prior rulemaking regarding the methodology, calculation, and application of the PCIA (R.17-06-026),[10] a consistent issue in this proceeding has been the Commission and ED's insistence on expedience to the detriment of transparency. Citing concerns that testimony, if submitted, would constitute "an undue consumption of time," the PD bases its conclusion on a thin record, relying principally on the ED's Staff Report finding that a cost shift among bundled and unbundled customers is "likely."[11]

However, the Commission has neither provided transparent data nor modeling demonstrating the rate impacts on bundled and unbundled customers. Parties have lacked the data needed to evaluate the Staff Proposals since the OIR was issued, including relative rate impacts to bundled and unbundled customers of any of the proposals in the Staff Report. Compounding this difficulty, an analysis of different combinations of Staff Proposals—including the combination the PD adopts—has never been provided, preventing parties from viewing a full picture of potential outcomes. Despite repeated calls for this data,[12] the Commission still has not responded. In addition, CalCCA requested updated data from ED to allow calculation of the rate impacts from the PD's proposed methodology, both at an in-person meeting and by email, neither of which has been answered.

This starkly contrasts R.17-06-026, which was initiated under urgency similar to that described by the Commission here. D.18-10-019 followed a substantial record including several rounds of comments, workshops, opening and rebuttal testimony, five days of evidentiary hearings, submission of opening and reply briefs, as well as supplemental briefs, and oral argument.[13] The record relied on by the PD here falls far short of that standard.[14] It comprises only the Staff Report, two rounds of comments and briefs (and testimony, not allowed into the record, from a fraction of parties). No data in the record or available to the parties would allow any "interested party" to gauge the extent of the "likely" cost

---

10 R.17-06-026, *Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment* (June 29, 2017).

11 Proposed Decision, at 10.

12 *See California Community Choice Association's Opening Comments on the Order Instituting Rulemaking and Energy Division Staff Report*, R.25-02-005 (March 18, 2025) (CalCCA Opening Comments), at 25; *California Community Choice Association's Reply Comments on the Order Instituting Rulemaking to Update and Reform Energy Resource and Recovery Account and Power Charge Indifference Adjustment Policies and Processes*, R.25-02-005 (April 2, 2025) (CalCCA Reply Comments), at 14-15.

13 D.18-10-019, at 10-12.

14 Proposed Decision, at 7-10.

shift identified in the Staff Report. CalCCA has continuously noted that the interested parties *cannot* perform an accurate analysis due to the lack of available information.[15] Other parties have also noted the thinness of the record on which the PD intends to base its decision.[16] It is unclear if the Commission itself has an idea of the impacts of its proposals—and there certainly is no record of those impacts.

Parties have, instead, been required to estimate the effects of proposed changes from the ED Staff proposals on each vintage by reproducing utility ratemaking *from 2025* to determine how much the PCIA would have changed *last year*. But even that is not possible with regard to the PD because it adopts a proposal the Staff Report does not analyze and fails to provide the updated RA MPBs for 2025 that would have resulted under the PD's preferred approach. Indeed, if the PD is adopted, LSEs will not have accurate data on which to plan their operations, and inform their customers, until the October ERRA updates. The change to the RA MPB calculation methodology contemplated in the PD could be a significant reallocation of costs between bundled and unbundled customers in the range of hundreds of millions of dollars or more. The current record cannot support such a major reallocation of costs.

III. THE PD SHOULD BE REVISED TO ADOPT AN RA MPB METHODOLOGY THAT ACCURATELY REFLECTS THE AFFIRMED MARK-TO-MARKET METHODOLOGY

Under section 366.2 of the Public Utilities Code, unbundled CCA customers are only responsible for "estimated net unavoidable electricity costs" that have been "reduced by the *value* of the benefits" in the IOUs' portfolios that accrue to bundled customers.[17] D.18-10-019 answered the question of how to determine the value of the capacity benefits that accrue to bundled customers. The cornerstone of that approach is to value an attribute as close as possible to the price at which it can be bought and sold *today*,[18] *i.e.*, "using reported purchase and sales prices of IOU, CCA, and ESP transactions made during (year n-1) for deliveries in (year n)."[19] CalCCA continues to urge the Commission to leave the RA MPB untouched, as the market rides through a short-term price spike. However, to the extent the Commission moves forward with changing the RA MPB, the PD rightly concludes that "the expedited nature of this

---

15 *See* CalCCA Opening Comments, at 25; CalCCA Reply Comments, at 14-15.

16 *See* Public Advocates Office Reply Comments on Track One Issues, R.25-02-005 (Apr. 2, 2025), at 6; *see also Reply Comments of the Coalition of California Utility Employees on Order Instituting Rulemaking and Energy Division Staff Report,* R.25-02-005 (Apr. 2, 2025), at 8; *Reply Comments of Shell Energy North America U.S., L.P. on the Order Instituting Rulemaking and Energy Division Staff Report of the 2024-2025 Resource Adequacy Price Benchmark*, R.25-02-005 (Apr. 2, 2025), at 6.

17 Cal Pub. Util. Code § 366.2(f)(2), (g).

18 D.18-10-019, at 73.

19 *Ibid.*

proceeding necessitates caution to ensure that the changes adopted work within the D.18-10-019 mark-to-market paradigm."[20]

The staler the data the RA MPB methodology uses, the further from the mark-to-market approach RA MPB is—and the further from indifference PCIA rates will be in 2026 and into the future. The PD's move to a three-year data set for the forecasted RA MPB and a four-year data set for the final RA benchmark commits error by getting the mark-to-market methodology wrong and failing to convey the value of benefits of the IOUs' capacity portfolios to departed customers by including stale data. While the PD touts the benefits of using the current local RA transaction timeframe so that no local RA is omitted from the dataset, aligning the data set for the new RA MPB with the Local RA timeframe is unnecessary, and arbitrary, given Local RA no longer drives the capacity market in California. Moreover, the Commission can achieve its goal of using a sufficiently robust data set to calculate the RA MPB without resorting to the use of old data that distort the market value. This end can be achieved by collapsing the benchmarks, as the PD already proposes, but using the existing data windows for the System and Flex RA MPBs. At worst, the PD should be modified to adopt DACC/AReM's proposal to use a narrower set of data that avoids the stalest of market transactions.

A. Staler Data Moves the Commission Further from D.18-10-019's Mark-to-Market Methodology

The PD suggests its goal is to include the "consideration of more data without undermining our mark-to-market principle." [21] While the PD gets the mark-to-market concept right in some places, it gets it wrong in others, creating an unnecessary internal tension that undermines its reasoning. As the PD recognizes when discussing its removal of affiliate, swap and duplicative sleeve transactions, the underlying data used to set the RA MPB should "be based upon competitive market pricing that reflects supply and demand dynamics."[22] Specifically, the data set should "reflect the market price/market value of the transaction to the transacting parties,"[23] and it should "reflect the market value driving the transaction."[24]

However, when expanding the data set to three and four-year windows, the PD suggests "the average market price associated with all contracts for deliverability in a specific year," *i.e.*, the average

---

[20] Proposed Decision, at 16, 18 (emphasis added).
[21] *Id.* at 19.
[22] *Id.* at 20, and Finding of Fact (FOF) 6, at 29.
[23] *Id.* at 20.
[24] *Id.* at 22.

price of contracts executed *years ago*, is somehow relevant to the price at which an attribute can be bought and sold today.[25] It similarly raises a nebulous and ill-defined concept of "full market value," echoing ED's conclusion that prices representing only "a small fraction of the RA resources procured" inaccurately reflect attribute value.[26] These statements get market dynamics and the mark-to-market methodology wrong.

Including data as far back as 2021 cannot act as a proxy for the *current* market value of capacity, *i.e.*, the value at which it can be bought or sold today. No reasonable mortgage lender would suggest home sales from 2021 establish the market value of single-family homes in San Francisco today. Instead, realtors and mortgage lenders use sale prices from comparable properties from the past few months or a year to value those properties. Similarly, no reasonable stockbroker would value a stock today based on the price it garnered in 2021. Doing so would result in substantially inaccurate valuations of those assets, cheating either the buyer or the seller out of significant value. But that is what the PD does for capacity: it uses stale data from 2021 to estimate the value of capacity in the market today,[27] undermining the accuracy of a benchmark designed to be a proxy for that market value.

Moreover, valuing all assets based on transactions that, in terms of volume, represent only a fraction of the total volume of the assets *is how markets work*. Stocks are valued based on a small percentage of sales for each stock each day. Only a fraction of the homes and condos that housed San Franciscans during the past 12 months were bought and sold during that time. But no reasonable realtor would set a sales price at "the average sales price" of all homes that housed San Franciscans during the past 12 months. Doing so would bring into the calculation the sales prices of homes that have not been sold for years, decades or even centuries. It is unreasonable for the PD to conclude a mark-to-market approach would use anything other than the most recent transactions necessary to ensure sufficient volumes exist to calculate a robust MPB. Doing so fails to convey the true value of the IOU's capacity resources to departed customers in violation of section 366.2.

B. The PD Unnecessarily Sacrifices Accuracy to Align with the Data Set Used to Calculate the Current Local RA MPB

Another faulty justification for expanding the data set to three and four years is that the Commission must do so in order to align the new data set with the current data set for transactions used

---

25 *Id.* at 13.
26 *Id.* at 13-15.
27 *Id.* at 19 ("Combining the MPB categories into a single RA MPB value based on the same temporal bucket currently adopted for local RA would provide a more accurate reflection of RA market costs.")

to set the Local RA MPB.[28] However, the data set used to calculate the RA MPB should "reflect the market value driving the transaction." [29] If the value of an attribute like Local RA is not driving the transaction, it does not reflect the "value of the transaction to the transacting parties;"[30] and, therefore, it undermines the accuracy of the resulting RA MPB. The PD moves in the opposite direction of accuracy, aligning the new data set with that used to calculate the least market-relevant attribute, *i.e.*, Local RA, instead of focusing on the most accurate valuation of the attributes actually driving RA transactions, *i.e.*, System RA and Flex RA. That is, the PD would have "the tail wag the dog."

The Commission need look no further than the observations in the PD itself to see this problem.[31] The PD explains that "RA might be purchased as local RA but then be used to meet system RA requirements."[32] While "[t]he existing MPB design disaggregates the local and flexible RA calculations from the system RA calculation," it does so based on the assumption that Local RA capacity "will command premiums compared to system RA."[33] However, the PD concludes that recent transactions show how System RA has been trading at a premium to Local RA, and this fact is "substantial evidence that the current RA MPB methodology is flawed in the current observed market dynamics."[34] The PD rightly concludes "that system requirements are the most constrained, even though local and flexible RA can meet these requirements."[35] In other words, it is System RA (and Flex RA) that are driving capacity transactions; not Local RA.

Those dynamics make sense. Local RA compliance obligations are met by SDG&E and the CPEs —not PG&E and SCE. [36] The cost of Local RA is irrelevant to the value of PG&E and SCE's capacity portfolios. When any money flows in PG&E and SCE's territory for the purpose of fulfilling a local compliance obligation, it flows from the CPE (not those utilities), and those costs are then recovered via the Cost Allocation Mechanism (not the PCIA).

---

28 *Ibid*.
29 *Id.* at 22.
30 *Id.* at 20.
31 *Id.* at 13-16, and FOF 3, at 28.
32 *Id.* at 13.
33 *Id.* at 15, 18.
34 *Ibid.*
35 *Id.* at 18.
36 *See* D.20-06-002, *Decision on Central Procurement of the Resource Adequacy Program*, R.17-09-020, at Ordering Paragraph 4.a (June 11, 2020) (LSEs served by a CPE can use their portfolio resources to meet their system and flexible RA needs unless the LSE bids those resources to the CPE into the CPE's resource solicitation).

The PD should not sacrifice accuracy to accommodate Local transactions. To the extent PG&E and SCE's PCIA portfolio includes resources that *could* provide Local RA, the portfolio includes them because those IOUs use those resources for *other* purposes (*i.e.*, for System or Flex RA compliance).[37] In its 2025 ERRA Forecast case, SCE conceded this point even for resources it shows to the CPE. SCE admitted that, when it uses Local RA as System or Flex RA, it retains the System RA attribute and will either use that attribute for its bundled customers' benefit, or will try and sell that attribute, also for its bundled customers' benefit.[38] It is therefore clear that SCE is retaining the capacity not for its Local RA value but for its System or Flex value. Said another way, bundled customers benefit from the System and Flex attributes of PG&E and SCE's PCIA-eligible capacity resources, not their Local attributes.

The fact SCE only deploys Local RA in its service territory for other purposes also can be seen in the SCE Financial Security Requirement (FSR) Advice Letter (AL) the Commission recently approved. The utilities' FSR fees are intended to protect the providers of last resort against incremental costs associated with customers returning to utility service.[39] In now approved AL 5339-E, SCE explains that its FSR methodology excludes costs related to Local RA because the CPE, not SCE, "recovers Local RA costs from all customers in SCE's service area."[40] Thus, SCE "would not incur incremental Local RA costs in a mass involuntary return as long as a CPE serves Local RA needs in SCE's service area."[41] If SCE will not incur incremental Local RA costs if customers return to its service territory, the Commission cannot credibly claim that a utility is deploying its current RA portfolio as Local RA to serve its current bundled customers' needs. The utility is using that capacity to meet either System or Flex RA needs.

Under section 366.2(g), now-departed customers should receive credit for the value of IOU resources based on the attributes that drive the most recent transactions. The value of accurately reflecting those transactions far outweighs the value of including Local RA transactions that are irrelevant in two-thirds of the State. That is, while the PD states it sees "no justification for reducing the amount of data considered," fixing the inaccuracy in the Commission approach is more than a sufficient

---

[37] *Ibid.* (LSEs served by a CPE can use their portfolio resources to meet their system and flexible RA needs unless the LSE bids those resources to the CPE into the CPE's resource solicitation).

[38] *See* A.24-05-007, Exh. CalCCA-02, *SCE Response to CalCCA DR 9.18* (Oct. 25, 2024).

[39] SCE AL 5339-E, *Southern California Edison Company's Implementation of Decision 24-04-009, Provider of Last Resort OIR, Phase 1*, at 7 (July 17, 2024).

[40] *Ibid.*

[41] *Ibid.*

justification.[42] The PD should therefore be revised to narrow the data window to only the most recent transactions.

C. If the Commission Must Modify the RA MPB, it Should Collapse the MPBs and Adopt DACC/AReM's Proposal to Ensure the MPB Reflects the Mark-to-Market Methodology

To the extent the Commission moves forward with modifying the RA MPB, it should, along with collapsing the MPBs into one, adopt DACC/AReM's proposal to ensure the MPB reflects the mark-to-market methodology. DACC/AReM's revised proposal includes in the data set: "eligible transactions executed in year (n-2) and Q1-3 of year (n-1) for delivery in year n, with additional true-up data added for year n."[43] These narrower 21 and 33-month data windows can achieve the Commission's goal for additional transaction data without sacrificing accuracy.

IV. THE PD COMMITS SIGNIFICANT LEGAL ERROR IN MANDATING THE USE OF THE REVISED MPB TO SET THE FINAL RA 2025 MPB

The PD commits two clear legal errors when it applies the revised MPB to the final RA for 2025.[44] Both arise from the PD's refusal to engage with the existence of contrary authority. First, the PD leaps to the erroneous, conclusory claim that its revisions to the PCIA ratesetting are not "general ratemaking" and can therefore be applied retroactively[45] despite *Edison*.[46] Second, the PD refuses to read two conflicting statutes in harmony, instead opting to ignore the restraints of section 728 that prove inconvenient to its conclusions.[47]

A. This Ratemaking Proceeding Sets General Rates

Edison is a complicated decision, but that does not excuse the Commission from proceeding through the *Edison* analysis—especially if it wants to receive any deference by a potential reviewing court.[48] Its failure to do so invites an Application for Rehearing for no other reason than to simply force the Commission to better explain its legal reasoning.

---

42 Proposed Decision, at 19.

43 DACC/AReM Opening Brief, at 12.

44 Proposed Decision, COL 10, at 31 ("The changes adopted should be applied to the calculation of the 2025 Final and 2026 Forecast RA MPB").

45 *Id.,* COL 9, at 31 ("Application of these changes to the 2025 Final RA MPB does not violate the prohibition against retroactive ratemaking."); *see also id.,* at 27.

46 *Southern Cal. Edison Co. v. Pub. Util. Comm'n,* (1978) 20 Cal.3d 813, 821 (*Edison*).

47 Proposed Decision, at 27.

48 *See Yamaha Corp. of America v. State Bd. of Equalization* (1998) 19 Cal.4th 1, 7-8 ("Where the meaning and legal effect of a statute is the issue, an agency's interpretation is one among several tools available to the court. Depending on the context, it may be helpful, enlightening, even convincing. It may sometimes be of little

Under *Edison*, the Commission does not have the authority to conduct retroactive general ratemaking.[49] The PD clearly imposes new rates on past behavior, but it concludes that this is not retroactive ratemaking in violation of *Edison*. It reaches that conclusion through a single, baseless, conclusory leap: "This OIR proceeding, and this decision, do not set general rates."[50] If the Commission were to adopt the PD's conclusion as is, without even a fig leaf of analysis, it would constitute clear legal error.

As a preliminary matter, the PD is wrong about what *Edison* stands for. *Edison* did not simply allow the Commission to issue any order "return[ing] surcharge fees to customers after [the Commission] found flaws in the methodology previously approved for collecting fees."[51] *Edison* only created an approved pathway for Commission decisions that overcome two hurdles. First, the rates at issue must not be set in general ratesetting.[52] Second, while the Commission may look backwards to calculate the difference between two values, it can only extract that amount through adjustments to a forward-looking rate.[53]

Regarding the first hurdle: drawing the distinction between general and non-general ratesetting was an easier question when *Edison* was decided 47 years ago. At that time, the Commission largely conducted ratesetting in general rate cases,[54] so it could easily look to the provenance of the rate and whether it was a general rate case or not. But much has changed in the Commission's ratesetting framework. Now, because the Commission has spread general ratesetting across tens of open ratemaking proceedings, identifying which side of *Edison*'s line a ratesetting action falls on requires resorting to the substantive analysis in *Edison*. Therefore, the question of whether general rates are being set hinges on the scope of the inquiry the Commission must use to set rates. If the ratesetting will be the result of a "plenary discussion" of broad policy considerations, and have a substantial impact on customers and

---

worth"); *see also Pac. Gas & Elec. Co. v. Pub. Util. Comm'n.* (2015) 237 Cal. App. 4th 812, 852 (granting a Commission decision a "minimal" "quantum of deference").

49 *Southern Cal. Edison Co. v. Pub. Util. Comm'n*, 20 Cal.3d 813, 821, 828-829 (1978).

50 Proposed Decision, at 27.

51 *Id.* at 26.

52 *Edison*, at 816.

53 *Id.*, at 824.

54 The Commission confirmed as much in Decision 86974 (SCE's 1976 general rate case), when it discussed how very few matters were pending when it had issued Decision 85294 (a partial general rate increase granted on December 30, 1975). At the end of 1975, the Commission had before it only "three matters affecting the overall rate design issue" for SCE, (*see* 1976 Cal. P.U.C LEXIS 59, *125-126), one of which was the fuel cost adjustment tariff decision that eventually got appealed up in *Edison*.

LSEs, then "general ratemaking" takes place.[55] If the ratesetting is simply an exercise in basic arithmetic to reflect verifiable costs, such that holding a hearing would be inefficient and unnecessary, then "general ratemaking" has not taken place.[56]

This PD—considering substantial questions of policy that will have far reaching impacts and not ministerially applying arithmetic to verifiable data—clearly sets general rates. But it avoids acknowledging that fact by refusing to walk through a single step of *Edison*'s substantive analysis on the difference between general and non-general ratesetting.

The PD fares no better at the second hurdle. If the PD had tried to clear *Edison*'s second hurdle, it would not have changed the existing rate at which RA is valued for 2025 via the true-up. Instead, it would have taken parallel steps to the three the Commission took in 1976:[57] Step A) True up 2025 PCIA rates using the existing RA value calculation, so as to not conduct retroactive ratemaking; Step B) Tabulate what the actual value of RA was in 2025 using load-serving entities' accounting entries; and Step C) Create a one-time rate mechanism to recoup—over the ensuing 24 to 36 months—the difference between A and B.

But even if the Commission were to try this, there is no way to conduct the analysis in Step B without crashing back into the first hurdle. There is no ministerial task the Commission can take to tally up outlays by gathering receipts and using simple arithmetic to arrive at the value of Retained RA.[58] Coming up with a number for Step B requires the Commission to make contentious policy decisions about *implicit* value with wide-ranging effects. This is not a value (like the cost of fuel already purchased, at issue in *Edison*) that can be calculated from the "application of a mathematical formula to a figure definitively established by reference to the utilities' books."[59] Were the PD to have attempted the second hurdle it would confront reality: the value it is setting is general ratemaking under *Edison*, and it fails to clear the first hurdle.

Lastly, had the PD not ignored *Ponderosa*—a case more directly on point and on which multiple parties relied—it might have appreciated what role *Edison* should play in its analysis. In *Ponderosa*, the Court of Appeals found prohibited retroactive ratemaking had occurred when the Commission

---

55 *Edison*, at 821, 828-829.

56 *Id.,* at 829 (citing *City of Los Angeles v. Pub. Util. Comm'n* (1975) 15 Cal.3d 680, at 695).

57 *See* P.U.C. Decision 85731, 1976 Cal. PUC LEXIS 1480, *18-*21.

58 *See, e.g.,* D.19-10-001, at 6 ("Market Value is the *estimated* financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the [PCIA] for a given year." (emphasis added)).

59 *Edison,* at 829.

retroactively revised a ratesetting formula—a change in methodology—for gains on sale of stock from a telephone company.[60] Like in *Ponderosa*, the PD revises a ratemaking formula that had been set via a rulemaking in a non-GRC ratesetting proceeding. And therefore, like in *Ponderosa*, the PD sets rates that are the product of general ratemaking that cannot be applied retroactively.

B. The PD Undermines Customer Confidence in Commission Rates

The PD's lack of legal analysis opens the door to an interpretation that all changes to the PCIA ratesetting methodology are not general ratemaking, can therefore be applied retroactively, and that such changes need only be based on weak data and analysis suggesting a cost shift is "likely" to occur. This alarming precedent could be read to empower the Commission to revise PCIA rates expansively *and* retroactively—not just for 2025—but for any past year in which the Commission's ever-changing standard for indifference has not been met. By undermining the California Supreme Court's boundary barring retroactivity, without providing any legal analysis to illuminate where that boundary exists, the Commission effectively eliminates any bar to retroactivity for PCIA rates. Under the PD, the narrow exception to retroactive ratemaking established in *Edison* swallows the rule, undermining ratepayer confidence in rates already set and electricity bills already paid.

C. The Commission Cannot Simply Choose to Enforce One Statute and Ignore Another

The PD makes the unusual conclusion that it can choose to enforce one statute (section 366's requirements for indifference) and ignore another statute (section 728's prohibition on retroactive ratemaking).[61] However, such an implicit repeal of section 728 is heavily disfavored; instead, the Commission must seek ways to interpret potentially conflicting statutes in a manner that preserves both statutes.[62]

Harmonizing these two statutes could involve the Commission adopting a bifurcated definition of indifference. For non-general ratesetting, indifference may be achieved *ex post*, through the operation

---

60 *Ponderosa Tel. Co. v. Pub. Util. Comm'n* (2011) 197 Cal.App.4th 48, 63-64.

61 Proposed Decision, at 27.

62 *See Even Zohar Construction & Remodeling, Inc. v. Bellaire Townhouses, LLC*, 61 Cal. 4th 830, 838 (2015) ("[W]e will find an implied repeal only when there is no rational basis for harmonizing … two potentially conflicting statutes [citation], and the statutes are irreconcilable, clearly repugnant, and so inconsistent that the two cannot have concurrent operation." (citations omitted)). This is especially the case when the statute that the Commission purports to ignore sounds in constitutional principles. *See Pacific Tel. & Tel. Co. v. Pub. Utils. Comm'n* (1965) 62 Cal.2d 634, 650 (relying on section 728 to cabin Commission powers, thereby avoiding due process or other constitutional questions). In that situation, constitutional avoidance canons also come into play requiring harmonization because making every effort to read both statutes in harmony (as opposed to ignoring one of them) helps the Commission ensure that its actions avoid constitutional concerns about regulatory takings. *See People v. Garcia* (2017) 2Cal.5th 792, 804.

of backwards-looking true-ups. But for general ratesetting, indifference can only be achieved *ex ante* (using an expected value framework) when the Commission considers all parties' evidence, arguments, and concerns and—given the uncertainty about the future—strikes the policy balance by setting rate frameworks (here, the framework established in D.18-10-019 and D.19.10-001). In other words, the current methodology established in D.18-10-019 and D.19-10-001 *defines indifference* for 2025; the Commission can only change that definition on a going-forward basis; it cannot do so retroactively.

V. THE PD SHOULD BE CLARIFIED TO ENSURE APPLICATION OF ANY NEW RA MPB METHODOLOGY IN FUTURE FORECAST AND FINAL MPBS

Language in the PD indicates an intention for any new RA MP methodology to be applied, effective immediately, to all future forecast and final MPB calculations.[63] The PD, however, fails to carry this intention forward into the conclusions of law. As discussed *supra*, the new methodology cannot be applied to the 2025 Final RA MPB. However, the decision should make clear any new calculation will be applied to all *future* forecast and final MPB calculations until a new methodology is determined in Track Two or further Commission proceeding. COL 10 should therefore be revised as set forth in Appendix A.

VI. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and requests adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the PD as provided in Appendix A, attached hereto.

Respectfully submitted,

Evelyn Kahl
General Counsel and Chief Policy Officer
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9815
E-mail: regulatory@cal-cca.org

Respectfully submitted,

Tim Lindl
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (510) 314-8385
E-mail: tlindl@keyesfox.com
On behalf of
California Community Choice Association

June 12, 2025

63 Proposed Decision, at 27.

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADOPTING CHANGES TO THE CALCULATION OF THE RESOURCE ADEQUACY MARKET PRICE BENCHMARK

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

Proposed text deletions show as ~~**bold and strikethrough.**~~ Proposed text additions show as **bold and underlined.**

FINDINGS OF FACT

4. ~~**The current RA MPB methodology examines a three-year dataset to determine the local RA MPB forecast, adding a fourth year to the dataset for the final local RA MPB.**~~ Adjusting the **RA MPB** methodology to a single RA MPB calculation, utilizing system, flexible, and local RA procurement data from ~~**the**~~ **two**~~**three**~~- and **three**~~**four**~~- year datasets**, as proposed by DACC/AReM,** allows for the consideration of more transaction data.

5. Combining the three MPBs into a single MPB with **two**~~**three**~~ years of data for forecast MPBs and an additional year of data for final MPBs appropriately balances data sufficiency with the Commission's currently established method of valuing RA portfolios based upon short-run market prices.

CONCLUSIONS OF LAW

1. The Commission's current RA MPB calculation methodology **may** lead~~**s**~~ to outcomes that are inconsistent with the requirements of Sections 365.2 and 366.3 and should be revised as described in this decision **to reduce the risk of such outcomes**.

2. The Commission should adopt a single RA MPB based upon **two**~~**three**~~-years' transaction data for the forecast calculation and **three**~~**four**~~-years' transaction data for the final calculation.

9. Application of these changes to the 2025 Final RA MPB ~~**does not**~~ violate**s** the prohibition against retroactive ratemaking.

10. The changes adopted should be applied to the calculation of the ~~**2025 Final**~~ ~~**and**~~ 2026 Forecast RA MPB **and in succeeding forecast and final MPBs until a new methodology is adopted by the Commission**. **The current methodology should be applied to the calculation of the 2025 Final RA MPB.**

ORDERING PARAGRAPHS

1. The Commission's Energy Division shall calculate a single Resource Adequacy (RA) Market Price Benchmark (MPB) for use in determining the annual Power Charge Indifference Adjustment (PCIA). The Energy Division shall utilize **two**~~three~~-years' transaction data when adopting the annual forecast RA MPB and **three**~~four~~-years' transaction data when adopting the annual final RA MPB. The Energy Division shall exclude from the calculation affiliate and swap transaction data. The Energy Division shall utilize a single transaction within a sleeve transaction in the RA MPB calculation.

2. The methodology adopted in this decision shall be effective ~~**immediately**~~**upon calculation of the 2026 Forecast RA MPB**.

FILED
06/13/25
04:59 PM
R2103011

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

Order Instituting Rulemaking to Implement Senate Bill 520 and Address Other Matters Related to Provider of Last Resort.	R.21-03-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROCEDURAL PATHWAY TO ADDRESS APPLICATIONS FOR PROVIDER OF LAST RESORT STATUS

Leanne Bober,
Director of Regulatory Affairs and
Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

June 13, 2025

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS

CalCCA[1] recommends that the Commission issue a Decision:

- Adopting the Ruling's proposed Procedural Pathway to close the proceeding and allow a non-IOU LSE to submit a Petition for Rulemaking twelve months prior to submitting an Application to serve as POLR; and

- Clarifying the Commission's authority over a Designated POLR through the adoption of the Ruling's proposed definition for "POLR-specific services" as those services "whose only purpose is to execute POLR responsibilities."

[1] Acronyms used in this Summary of Recommendations 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 520 and Address Other Matters Related to Provider of Last Resort.	R.21-03-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROCEDURAL PATHWAY TO ADDRESS APPLICATIONS FOR PROVIDER OF LAST RESORT STATUS

California Community Choice Association[2] (CalCCA) submits these opening comments pursuant to the *Administrative Law Judge's Ruling Seeking Comment on Procedural Pathway to Address Applications for Provider of Last Resort Status*[3] (Ruling), dated May 28, 2025.

I. INTRODUCTION

At this time, none of CalCCA's community choice aggregator (CCA) members seek to serve as a non-investor-owned utility (IOU) provider of last resort (POLR) (hereinafter referred to as a "non-IOU load serving entity (LSE) POLR" or a "Designated POLR"). CalCCA supports the approach set forth in the Ruling for the California Public Utilities Commission (Commission) to: issue a Decision (1) closing the proceeding now, but allowing a non-IOU LSE to submit a

---

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 Rulemaking (R.) 21-03-011, *Administrative Law Judge's Ruling Seeking Comment on Procedural Pathway to Address Applications for Provider of Last Resort Status* (May 28, 2025).

Petition for Rulemaking (PFR) twelve months prior to submitting an application to serve as the Designated POLR; and (2) clarifying the Commission's overall authority to regulate the Designated POLR pursuant to Public Utilities Code sections 216 and 387[4]. Such authority should be clarified, in part, through the definition of "POLR-specific services" proposed in the Ruling, *i.e.*, as those services "whose only purpose is to execute POLR responsibilities [*e.g.,* when a [LSE] fails, transferring that LSE's customers to the POLR]." The other manner in which to clarify the Commission's authority is to refrain from defining "Fully-severable services" or "Non-severable services." There is no need for such definitions since all non-POLR-specific services are severable from POLR services, as demonstrated below and in CalCCA's January 24, 2025, Reply Comments (CalCCA's Reply Comments) in this proceeding. [5]

CalCCA therefore recommends that the Commission issue a Decision:

- Adopting the Ruling's Procedural Pathway to close the proceeding and allow a non-IOU LSE to submit a Petition for Rulemaking twelve months prior to submitting an Application to serve as POLR; and
- Clarifying the Commission's authority over a Designated POLR through the adoption of the Ruling's proposed definition for "POLR-specific services" as those services "whose only purpose is to execute POLR responsibilities."

II. THE PROPOSED PROCEDURAL PATHWAY SHOULD BE ADOPTED

The Commission should adopt the Ruling's proposed procedural pathway as a reasonable solution to immediately satisfy the requirements of California Public Utilities Code section 387, while delaying the full build-out of the non-IOU LSE framework until a non-IOU entity seeks to become a POLR. While section 387 requires the Commission to develop threshold attributes for

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

5 *See California Community Choice Associations Reply Comments on Threshold Questions,* R.21-03-011 (Jan. 24, 2025), at 14-16 (CalCCA Reply Comments).

a Designated POLR, there is no deadline by which the Commission must do so. The Ruling's proposed procedural pathway would result in the Commission issuing a decision that:

1) Provides a "framework for [the Commission's] regulatory authority over a non-IOU POLR and the services it provides";
2) Closes the instant proceeding; and
3) Directs any non-IOU entity that seeks POLR status to first file and serve a PFR at least 12 months before filing an application to assume POLR responsibilities.[6]

Upon receipt of a PFR, the Commission would "resume its consideration of the threshold questions and topic areas identified in the Scoping Memo."[7]

As noted in CalCCA's Reply Comments, none of CalCCA's member CCAs have expressed near-term interest in taking over POLR services from the IOUs.[8] Therefore, CalCCA agrees with the Commission's proposed procedural pathway. The Commission should conserve its limited resources and the resources of other parties by refraining from going further than resolving the overall framework regarding Designated POLR service.

III. THE COMMISSION'S STATUTORY AUTHORITY OVER A NON-IOU LSE POLR EXTENDS ONLY TO "POLR-SPECIFIC SERVICES"

The Ruling questions "how and to what extent the Commission would regulate the services provided by a non-IOU LSE POLR."[9] The Ruling requests party comment on the following definitions to clarify its regulatory authority:

- **POLR-specific services:** Services whose only purpose is to execute POLR responsibilities [*e.g.,* when a Load Serving Entity (LSE) fails, transferring that LSE's customers to the POLR].
- **Fully-severable services:** Services that do not affect the provision of POLR services.

6 Ruling at 2-3.
7 *Id.* at 3.
8 *See* CalCCA Reply Comments, at 5.
9 Ruling, at 2.

- **Non-severable services:** Services that are neither POLR-specific nor fully severable."[10]

CalCCA supports the Ruling's approach to framing the overall regulatory authority of the Commission now, thereby establishing the scope of Commission regulation LSEs can expect if or when interest develops in Designated POLR service. Indeed, by providing clarity regarding the nature of the Commission's authority over a Designated POLR—and confirming that it extends no further than a Designated POLR's "POLR-specific services"—the Commission may well shape interest in the Designated POLR framework, even if that interest is limited now.

As described below, in defining the Commission's authority over a non-IOU LSE POLR, the Commission need only adopt its definition of "POLR-specific services" because: (1) the plain language of Public Utilities Code sections 216 and 387 explicitly and unambiguously limits the Commission's statutory authority over a non-IOU LSE to "POLR-specific services"; (2) the legislatively protected autonomy of CCAs must be preserved; and (3) "POLR-specific services" can be isolated and defined separately from all other CCA services. Defining "Fully-severable services" or "Non-severable services" is unnecessary and in all events these services will fall outside the Commission's jurisdiction.

A. The Plain Language of Public Utilities Code Sections 216 and 387 Limits the Commission's Statutory Authority Over a Non-IOU LSE to "POLR-Specific Services"

Public Utilities Code sections 216 and 387 provide the statutory framework for the Commission's authority over a Designated POLR, restricting such authority to "POLR-specific services." Section 387(j) states:

---

[10] Ruling, at 3.

> The commission shall supervise and regulate each provider of last resort***, as necessary,*** as a public utility ***for the services provided by the provider of last resort pursuant to this article to ensure the provision of electrical service to customers without disruption if a load-serving entity fails to provide, or denies, service to any retail end-use customer in California for any reason***. The commission may do all things that are necessary and convenient in the exercise of this power.[11]

Section 387(j) therefore establishes that although the Commission is authorized to exercise a degree of regulatory supervision over a Designated POLR, the Commission's authority is ***limited to that LSE's POLR-specific services***.

The Commission must give meaning to section 387(j)'s explicit statutory limitation when framing its regulatory authority over the Designated POLR. "It is a maxim of statutory interpretation that courts should give meaning to every word of a statute and should avoid constructions that would render any word or provision surplusage."[12] The legislature explicitly provided the Commission's ability to regulate POLRs "as necessary, as a public utility" ***only*** "for the services provided by the provider of last resort . . . to ensure the provision of electrical service to customers without disruption if a load-serving entity fails to provide . . . service[.]"[13] The concluding clause of that statutory language therefore explicitly limits the Commission's authority to regulate the Designated POLR to ***only*** the Designated POLR's ***POLR-specific services,*** which are the services the Designated POLR must provide to ensure service without disruption if an LSE fails to provide, or denies, service to retail end-use customers.

Had the legislature not intended the emphasized language to be a limitation on Commission authority, there would be no reason to include it at all in section 387(j). Instead, the legislature could have simply directed that once an entity becomes a Designated POLR, the

---

11 Cal. Pub. Util. Code § 387(j) (emphasis added).

12 *Tuolumne Jobs & Small Bus. Alliance v. Superior Court*, 330 P.3d 912, 1038 (Cal. 2014).

13 Cal. Pub. Util. Code § 387(j).

Commission has authority to regulate that entity as a "public utility." That broader regulatory authority would necessarily include the ability to supervise the Designated POLR's POLR-specific services. So, to give meaning to ***all of section 387(j)***, as California law requires, the Commission must recognize that its ability to regulate a Designated POLR is ***limited*** to "POLR-specific services."

The other statutory provision affected by SB 520[14], section 216(a)(2), supports this conclusion:

> A provider of last resort, as defined in Section 387 . . . is a public utility subject to the jurisdiction, control, and regulation of the commission and the provisions of this part ***regarding providing that service***.[15]

Like section 387(j), this statutory provision is expressly limited by its concluding clause. Once again, the legislature determined that a Designated POLR is a "public utility" merely for the purpose of the Designated POLR's POLR-specific services, as the non-IOU LSE that becomes POLR is a "public utility" ***only*** "regarding providing that service."[16] This interpretation gives meaning to all of section 216(a)(2), as the Commission must.[17] This interpretation also harmonizes section 216(a)(2) with the Commission's expressly limited authority under section 387(j), as California law directs.[18]

---

14 Senate Bill No. 520 (SB 520) (Hertzberg, Chapter 408, Statutes of 2019).
15 Cal. Pub. Util. Code § 216(a)(2) (emphasis added).
16 *Id.*
17 *Id.* § 387(j) (emphasis added).
18 *See, e.g.*, *ZB, N.A*, *and Zions Bancorporation v. Superior Court,* 448 P.3d 239, at 248 (Cal. 2019); *Tuolumne Jobs*, 330 P.3d at 1038.

B. Any POLR Framework Must Preserve the Legislatively Protected Autonomy of Non-IOU LSEs By Limiting the Commission's Jurisdiction to POLR-Specific Services

Limited Commission authority is also consistent with existing Commission oversight—and consistent with California law—over CCAs. CCAs are obligated to comply with certain procurement and reliability obligations (including the Commission's Resource Adequacy (RA), Integrated Resource Planning (IRP), and Renewable Portfolio Standards (RPS) programs), but CCAs are not subject to the Commission's rate, procurement, or financial oversight in the same manner as IOUs because, as public agencies, they are directly responsive to their customers. CCAs are also subject to numerous legal restrictions on public agency operations, including ratemaking.[19]

The public agency accountability and other provisions of State law ensuring that CCA charges remain in line with the reasonable costs of CCA service are analogous to the Commission's review of IOU rates and services and displaces the need for the same sort of regulatory supervision the Commission exercises over the IOUs. The need for extensive Commission jurisdiction is further reduced by the fact that POLR service is and should be rare and time limited. It only occurs in the case of returned load, and then only for a limited period of time before returned customers are either folded into the default provider's "normal" non-POLR service options, or returned customers depart POLR-service for a separate service option.

---

[19] As set forth in Public Utilities Code § 366.2, CCAs are formed for the purpose of aggregating the electrical load of interested customers in their service territory to procure electricity and energy services on those customers' behalf. Similar to municipal utilities, CCAs are public agencies. Their governing boards are comprised of local elected officials from the cities and counties that form the CCA. CCA governing boards exclusively set the rates for their electricity services. In addition, as public agencies, CCAs are subject to California open meeting, public record, and conflict of interest laws such as the Ralph M. Brown Act, the Public Record Act, and the Political Reform Act. CCA governing boards set electrical rates for their customers within a public process that already provides for decisions made in the public interest, with transparency, public participation, and public agency accountability.

Section 387(j) contemplates a continuation of the Commission's existing authority over non-IOU LSEs. The legislature has authorized the Commission a degree of expanded regulatory authority over a Designated POLR, but the statute is explicit that this expanded authority should ***only*** encompass POLR-specific services. The Commission must comply with that explicit legislative mandate when structuring the Designated POLR Framework.

C. The Commission Need Only Adopt the Ruling's Definition for "POLR-Specific Services"

Regardless of the structure created by the Designated POLR to provide POLR service, the *only* services the Commission will have the ability to regulate are those defined by statute, which are *"the services . . . to ensure the provision of electrical service to customers without disruption if a load-serving entity fails to provide, or denies, service to any retail end-use customer in California for any reason*."[20] As described in CalCCA's Reply Comments,[21] there are feasible avenues through which a Designated POLR can elect to offer distinct POLR services. The Application of a non-IOU LSE to serve as POLR is the appropriate venue to determine these specifics. Nothing in California law forecloses that ability.

The Commission will fulfill its regulatory role under sections 216(a)(2) and 387 by regulating the POLR-specific services of a Designated POLR only. "Fully severable services" will be those that are *not* POLR-specific services, and "Non-severable services" will not exist given the Designated POLR will be able to isolate and define the services need to provide the limited POLR services to customers. Therefore, the only defined term necessary to frame the Commission's regulatory authority over a Designated POLR is the Ruling's "POLR-specific services," which should be adopted.

---

20 *Id.* (emphasis added).

21 CalCCA Reply Comments, at 15-16 (describing three alternative structures for a non-IOU LSE to provide "POLR-specific services").

IV. CALCCA COMMENTS ON QUESTIONS POSED IN THE RULING

1. Comment on the definitions below. What edits, if any, do you propose to the definitions? Is this list mutually exclusive and collectively exhaustive of the services a POLR provides? If not, please provide examples of services that are not covered by any of the definitions below or could reasonably be covered by more than one definition. Provide the policy and statutory bases for your response.

Please see Section III., above.

a. POLR-specific services: Services whose only purpose is to execute POLR responsibilities [e.g., when a Load Serving Entity (LSE) fails, transferring that LSE's customers to the POLR].

The Commission should adopt this definition of "POLR-specific services," as set forth in Section III., above.

b. Fully-severable services: Services that do not affect the provision of POLR services.

Adopting a definition of "Fully-severable services" is unnecessary, as set forth in Section III., above.

c. Non-severable services: Services that are neither POLR-specific nor fully severable.

Adopting a definition of "Non-severable services" is unnecessary, as set forth in Section III., above.

2. What is the best procedural path that accomplishes the goals of (1) meeting statutory guidance, (2) providing parties with near-term guidance on important issues (which, as proposed in this ruling, would be limited to the Commission's framework to regulate non-IOU POLR services), (3) providing a path to resolve the issues identified in the Scoping Memo, and (4) preserving Commission and party resources until those issues are immediately relevant?

The Commission should adopt the Ruling's suggested procedural path, as set forth in Section II., above.

a. Do you support the approach described in the Procedural Path Forward section? What changes would you propose to that approach?

CalCCA supports the Ruling's suggested procedural path, as set forth in Section II., above.

b. Would you recommend an alternative path? If so, please describe your alternative proposal and explain how it achieves the four goals described above.

CalCCA would not recommend an alternative path.

i. If you propose for the Commission to resolve all the issues in the Scoping Memo immediately, set forth the basis for this position and your position on how to resolve the core issues that need to be resolved prior to a non-IOU entity filing an application to serve as a non-IOU POLR.

Not applicable, as CalCCA supports the Ruling's suggested procedural path, as set forth in Section II., above.

ii. If you recommend addressing the issues at a later date, explain how the Commission should decide to resume consideration of those issues.

Not applicable, as CalCCA supports the Ruling's suggested procedural path, as set forth in Section II., above.

V. CONCLUSION

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

Respectfully submitted,

Leanne Bober

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

June 13, 2025

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.

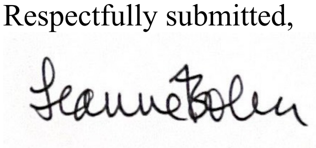
6. GridInfra3B (Short-Term Forecasting)

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

FILED
06/16/25
04:59 PM
R2310011

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Lauren Carr,
Senior Market Policy Analyst
Eric Little,
Director of Market Design

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
(510) 980-9459
E-mail: regulatory@cal-cca.org

June 16, 2025

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS

- San Diego Gas & Electric Company's (SDG&E's) support for declining to adopt hourly load obligation trading is unfounded and should be rejected;
- The PD[1] should be modified to adopt the same planning reserve margin (PRM) for all load-serving entities (LSEs), with a waiver for market power mitigation, because party comments demonstrate that the effective PRM has been unsuccessful;
- Parties' recommendations for additional modeling and stakeholder engagement before adopting the 2027 PRM should be adopted; and
- The PD should be modified to refrain from dictating how to allocate imbalance reserve (IR) and reliability capacity (RC) revenues, as supported by party opening comments.[2]

---

[1] Rulemaking (R.) 23-10-011, *Opening Comments on The Proposed Decision Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinement* (May 22, 2025) (PD).

[2] References to parties' Opening Comments herein refer to Opening Comments filed in this proceeding (R.23-10-011), on or about June 11, 2025.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION

The California Community Choice Association submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Opening Comments on The Proposed Decision Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements*, dated May 22, 2025.

I. INTRODUCTION

In these reply comments, CalCCA addresses three themes within parties' Opening Comments. *First*, SDG&E continues to advance unfounded claims that hourly load obligation trading could encourage "leaning" and create "inequitable" outcomes.[3] SDG&E has provided no support for these claims in its Opening Comments, or elsewhere in the record. Neither has any other party. The Commission, therefore, should not use SDG&E's unsupported claims as the basis for any decision-making.

Second, parties' Opening Comments continue to diverge on the right level of PRM necessary to meet a 0.1 loss-of-load expectation (LOLE). What is clear, however, is that: (1) the investor-owned utilities (IOUs) have been ineffective at procuring resources to meet the effective PRM in a cost-effective and reliable manner; and (2) continued development and vetting of LOLE modeling is necessary to assure future PRMs meet 0.1 LOLE targets, such that the resource adequacy (RA) program achieves the right level of reliability and affordability for customers. For these reasons, the Commission should allow *all* LSEs procure to the same PRM (with the opportunity for a waiver to mitigate market power) and allow additional opportunity for development and vetting of LOLE modeling, with the opportunity for stakeholders to share their own modeling.

Third, parties' Opening Comments demonstrate why it is necessary for the Commission to refrain from requiring that RA contracts specify the method for allocating IR and RC revenues. Because this is strictly an issue of cost and not reliability, the Commission should allow LSEs and their counterparties to determine how to allocate those revenues.

II. SDG&E'S SUPPORT FOR DECLINING TO ADOPT HOURLY LOAD OBLIGATION TRADING IS UNFOUNDED AND SHOULD BE REJECTED

The Commission should reject SDG&E's unfounded support for the rejection of hourly load obligation trading. SDG&E supports the PD's findings on hourly load obligation trading and states the

---

[3] SDG&E Opening Comments, at 4.

proposal, "could encourage leaning and inequitable outcomes among LSEs, which is particularly problematic in the context of the Commission's affordability goals."[4] SDG&E's claims are unfounded and should not inform the Commission's decision-making in any way.

SDG&E has provided no support for these claims in its Opening Comments, or elsewhere in the record. Neither has any other party. On the other hand, CalCCA has explained in detail how hourly load obligation trading will not encourage leaning or create any inequitable outcomes.[5] Hourly load obligation trades are products for which one LSE would pay another at a price agreed upon by the parties, just like any other RA product. Also like any other RA product, hourly load obligation trades would need to be shown and validated by Energy Division (ED), assuring that all RA requirements continue to be met, either through the procurement of resources or the procurement of hourly load obligation trades. CalCCA has demonstrated hourly load obligation trading will support the Commission's affordability goals, not hinder them.[6] For these reasons, the Commission must reject SDG&E's unsupported claims.

Instead, the Commission should modify the PD to adopt hourly load obligation trading. As stated by Shell Energy North America (US), L.P. (Shell):

> [a]bsent action now, hourly load trading would be implemented, at the earliest, for the 2027 compliance year…Given the potential opportunity to reduce ratepayer costs, and LSE penalties, it seems counterproductive to delay implementation for that period of time, and inconsistent with the Commission's recognition of ongoing ratepayer affordability challenges.[7]

As Shell recommends, if the Commission is concerned about the implementation of hourly load obligation trading, it should adopt a limit on the amount of load obligations an LSE can trade.[8] The Commission should not adopt Shell's recommendation to require the filing of a Tier 1 Advice Letter (AL) for approval for the trade,[9] however, as the time required for Tier 1 AL is not necessary because it: (1) inhibits the ability to use hourly load obligation trades; (2) is not required for other RA products; and (3) will be duplicated in the month-ahead showing process, where the transaction will be validated for compliance.

---

4 *Ibid.*

5 *California Community Choice Association's Reply Comments on the Assigned Commissioner's Amended Scoping Memo and Ruling*, R.23-10-011 (Mar. 17, 2025), at 8-9.

6 *See California Community Choice Association's Proposals on Track 3*, R.23-10-011 (Jan. 17, 2025), at 10-11.

7 Shell Opening Comments, at 5.

8 *See Id.,* at 4.

9 *See Id.,* at 4-5.

III. THE PD SHOULD BE MODIFIED TO ADOPT THE SAME PRM FOR ALL LSES, WITH A WAIVER FOR MARKET POWER MITIGATION, BECAUSE PARTY COMMENTS DEMONSTRATE THAT THE EFFECTIVE PRM HAS BEEN UNSUCCESSFUL

The Commission should modify the PD to adopt a 21 percent PRM in the summer months for all LSEs with the ability to request a waiver for procurement above 15.5 percent. This is because parties' opening comments and the record demonstrate (1) a significant amount of uncertainty around the level of PRM necessary to achieve a 0.1 LOLE;[10] (2) the need to mitigate the potential exertion of market power for procurement above 17 percent;[11] and (3) the inability of the effective PRM framework to meet reliability targets.[12]

While there continues to be significant uncertainty around the level of PRM needed to achieve a 0.1 LOLE reliability target, opening comments demonstrate that the effective PRM has been unsuccessful at achieving reliability outcomes in a cost-effective manner. Multiple parties state that the IOUs have been ineffective at procuring enough capacity to achieve the effective PRM targets – even with the ability to procure non-RA eligible resources.[13] For example, Terra-Gen states that the IOUs, "procured only 995 MW against a nonbinding requirement of 1,700 MW, resulting in merely 2.34% of additional PRM procurement above the 2024 17% PRM."[14] When the IOUs are short on their effective PRM procurement, as they were in 2024, the CAISO cannot backstop to fill the deficiency.[15] The RA program would therefore be more reliable if the Commission set the same PRM for *all* LSEs, consistent with the Commission's objective to transfer full procurement responsibility to individual LSEs,[16] with

---

10 *See* California Independent System Operator Opening Comments (CAISO), at 1; the California Environmental Justice Alliance Opening Comments, at 2-3; CalCCA Opening Comments, at 8-11; Microsoft Corporation (Microsoft) Opening Comments, at 3; Pacific Gas and Electric Company Opening Comments, at 1; Southern California Edison Company (SCE) Opening Comments, at 3; SDG&E Opening Comments, at 2-3; Terra-Gen, LLC (Terra-Gen) Opening Comments, at 3-5; and Western Power Trading Forum Opening Comments, at 7-8.

11 *See* CalCCA Opening Comments at 11-12; *Comments of the Public Advocates Office on Track Proposals*, R.23-10-011 (Mar. 3, 2025), at 6-7; and *SCE's Opening Comments on All Proposals Filed*, R.23-10-011 (Mar. 3, 2025), at 2.

12 *See* AES Opening Comments, at 4; California Clean Energy Buyers Association Opening Comments, at 4; California Energy Storage Alliance Opening Comments, at 11; and Terra-Gen Opening Comments, at 4.

13 *Ibid.*

14 Terra-Gen Opening Comments, at 4.

15 CAISO Opening Comments, at 4.

16 *See* PD at 29.

the opportunity for a waiver to mitigate market power only when LSEs demonstrate commercially reasonable efforts. This would allow the CAISO to backstop if LSEs cannot meet their targets.

IV. PARTIES' RECOMMENDATIONS FOR ADDITIONAL MODELING BEFORE ADOPTING THE 2027 PRM SHOULD BE ADOPTED

Many parties' opening comments recognize that the PRM modeling continues to require further evaluation.[17] While the Commission should ultimately seek to change the PRM on a bi-annual basis to provide more certainty about procurement needs to LSEs managing their RA position, this should only occur after stabilizing the process and methodology for arriving at a PRM. Given the recommended PRM continues to swing in each subsequent study, the Commission should instruct ED to continue refining the PRM with new modeling and a new stakeholder process, in which parties can present their own modeling, before adopting a value for 2027. If that process arrives at a stable result, the Commission can implement a bi-annual process with the next PRM calculation in 2028.

V. THE PD SHOULD BE MODIFIED TO REFRAIN FROM DICTATING IR AND RC REVENUE ALLOCATION, AS SUPPORTED BY PARTY COMMENTS

The Proposed Decision (PD) requires that:

> For contracts executed after the issuance of this decision, the contracting LSE shall specify in the RA contract that any CAISO revenues for [IR or RC] products shall be credited back to the LSE that has procured the RA capacity value of the resource.[18]

The stated rationale is the Commission's intent to avoid "provid[ing] needless revenue streams, or the ability to double-recover costs, to generators."[19] However, this requirement is not grounded in a reliability concern, but rather in an assumption about optimal economic outcomes. Because this assumption will not hold in all cases, the PD should not impose a one-size-fits-all mandate. Furthermore, by focusing on contract economics rather than reliability outcomes, the PD exceeds the Commission's jurisdiction over non-investor-owned utility (IOU) load-serving entities (LSEs), such as community choice aggregators (CCAs) and electric service providers (ESPs).

Generators must recover their costs and earn a reasonable return through revenues from all the products they sell. In today's market, where increased penetration of zero-marginal-cost resources has eroded energy market revenues, capacity payments and other attributes such as IR and RC have become

---

17 *See* CAISO Opening Comments, at 6; Central Coast Community Energy Opening Comments, at 4; Clean Energy Buyers Association Opening Comments, at 9; Microsoft Opening Comments, at 7-8; and SCE Opening Comments, at 3.

18 PD at 83.

19 *Ibid.*

more critical to cost recovery. By requiring that all IR and RC revenues be credited to the LSE, the PD undermines contractual flexibility that could otherwise enable more efficient outcomes—such as lower RA prices in exchange for allowing generators to retain those revenues. The assumption that channeling IR and RC revenues to the LSE will always produce the most cost-effective result is incorrect and constrains LSEs from pursuing alternative, potentially lower cost contracting arrangements.

Moreover, while the Commission exercises broad authority over IOU procurement through the bundled procurement plan process, it does not have equivalent authority over CCA and ESP contracting practices. The Commission may require CCAs and ESPs to meet certain policy mandates—such as RA and the Renewables Portfolio Standard (RPS)—but it lacks jurisdiction to dictate the specific terms and conditions of their procurement agreements beyond what is necessary to ensure compliance with reliability and clean energy goals.

Because the allocation of IR and RC revenues is fundamentally a question of contractual economics—not reliability—the Commission's attempt to impose a blanket revenue allocation requirement intrudes into procurement decision-making where it lacks legal authority. If the Commission is concerned about IOU contracting practices related to IR and RC revenues, it may appropriately address those issues through the IOUs' bundled procurement plans. However, the same logic does not extend to CCA and ESP procurement, which remains outside the Commission's authority to regulate in this manner.

Accordingly, the PD's proposed requirement that all IR and RC revenues flow to the LSE should be removed. Instead, LSEs should retain flexibility to negotiate revenue-sharing provisions in a manner that supports cost-effective procurement and reflects the diversity of market structures in California.

VI. 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

June 16, 2025

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

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON THE PROPOSED DECISION**

Evelyn Kahl
Chief Policy Officer and General Counsel
Leanne Bober
Director of Regulatory Affairs and
Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9815
E-mail: regulatory@cal-cca.org

Tim Lindl

KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (510) 314-8385
E-mail: tlindl@keyesfox.com

On behalf of
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

June 17, 2025

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS

In response to Opening Comments on the Proposed Decision, CalCCA recommends that the Commission:

- Reject the Joint IOUs' recommendation to include in the definition of "affiliate "any Joint Powers Agency [JPA] or partnership in which a load serving entity is a member" given that this definition would result in the exclusion of transactions by individual CCAs who are members of JPAs such as CC Power, which do not fall within the non-market based affiliate transactions the PD seeks to exclude;
- Reject the PD's proposed timeframe of transactions to include in the RA MPB as supported by parties including the Joint IOUs and CUE, given this timeframe is not supported by the record and will decrease the accuracy of the RA MPB; and
- Reject the PD's adoption of the new calculation methodology for the Final 2025 RA MPB, as such adoption would constitute impermissible retroactive ratemaking.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION

CalCCA[1] submits these reply comments to the PD[2] pursuant to Commission Rule 14.3.

I. THE JOINT IOUS' DEFINITION OF AFFILIATE SHOULD BE REJECTED

The Commission should reject the Joint IOUs' recommendation, inexplicably raised for the first time after the OIR comments, briefing, and after the record has closed, to add to the PD's definition of "affiliate" "any Joint Powers Agency or partnership in which a load serving entity is a member."[3] This recommendation specifically targets CCAs procuring capacity through joint powers agencies (JPAs) such as California Community Power (CC Power). The only support the IOUs offer to add this far-reaching phrase is a circular statement that it "should be" added—without citation to the record or any authoritative source.[4]

The addition of JPAs to the definition of "affiliate" is inapposite and should be rejected. The Commission's goal in eliminating affiliate transactions from the RA MPB is to exclude transactions that *do not* reflect true supply and demand characteristics.[5] The PD also refers specifically to transactions "wherein the benefits of the transaction can accrue to the same entity."[6] To the contrary, the joint procurement that CCA members conduct through CC Power *does* reflect true supply and demand dynamics, the transactions *do not* benefit the same entity, and they have *no potential* to skew the calculation of the RA MPB. There is no reason to exclude such transactions from the data set.

Indeed, the procurement CCAs jointly conduct via CC Power do not include separately priced transactions between CC Power and its members. Participating members pay the contract price CC Power negotiates on their behalf. CC Power does not sell or resell energy, capacity, or RECs to its

---

1 CalCCA 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, *Decision Adopting Changes to the Calculation of the Resource Adequacy Market Price Benchmark* (May 23, 2025) (Proposed Decision or PD).

3 *See* Joint IOU PD Opening Comments, at 4.

4 *Ibid*. (stating the definition of affiliate "should also address arrangements between a CCA and a Joint Powers Agency in which the CCA is a member").

5 Proposed Decision, at 21.

6 *Ibid*.

member CCAs at a price different than what is paid to the counterparty. Those CCAs negotiate the purchase of energy, capacity, and renewable attributes *through* CC Power, but the purchased products will be delivered directly to each participating CCA without CC Power ever taking delivery or title. Moreover, CC Power and its members are not affiliates under the Commission's definition, which recognizes that an affiliate of an entity owns, is owned by, exercises control over, or is controlled by that entity.[7] CC Power does not own, exercise control over, and is not controlled by, any one of its CCA members, but rather is jointly controlled by a group of CCAs. CCAs and JPAs such as CC Power are not corporate entities. They are non-profit entities created by local governments and have neither the "controlling corporations" nor "subsidiaries" referenced in the definition the Joint IOUs propose.[8]

The PD also notes its concern that transactions could be "double counted."[9] However, the transactions the CCAs conduct through CC Power do not raise double-counting concerns. CC Power is not an LSE. It does not receive data requests regarding its RA procurement, and only its CCA members report their individual transactions conducted via CC Power. In fact, excluding these transactions from the data set would work to the opposite of the PD's intent, eliminating RA transactions and skewing the RA MPB. The IOUs' inclusion of JPAs in the "affiliate" definition would also result in the incorporation of much more than CC Power transactions, as all members of CC Power would be labeled affiliates *of each other*. That is, a transaction between one CCA member in response to another CCA member's RFO—a transaction that clearly has been exposed to the market and is not an affiliate transaction—could be deemed such a transaction and be removed from the data set. There is no justification for the loss of such market data. For all these reasons, the IOUs' recommendation to incorporate JPAs into the definition of "affiliate" should be rejected.

II. THE PROPOSED THREE- AND FOUR-YEAR DATA WINDOW SHOULD NOT BE ADOPTED BECAUSE IT IS UNSUPPORTED BY THE RECORD AND WOULD DECREASE ACCURACY IN THE MARKET PRICE BENCHMARK

The current record is insufficient to support the PD's adoption of a three-year transaction window for the forecast RA MPB and a four-year transaction window for the final RA MPB. As CalCCA has emphasized, the record does not include data sufficient to allow stakeholders–or the

---

[7] D.06-12-029, *Opinion Adopting Revisions to (1) The Affiliate Transaction Rules and (2) General Order 77-L, As Applicable to California's Major Energy Utilities and Their Holding Companies*, R.05-10-030 (Dec. 14, 2006), App. A-3, at 1.

[8] Joint IOU PD Opening Comments, at 4.

[9] Proposed Decision, at 23.

Commission–to quantify the impacts of these proposals.[10] Most parties who submitted opening comments agree.[11]

Parties who do agree with the PD's conclusions do so without evidence of their own. CUE states that the record supports a conclusion that trading volumes have impacted the accuracy of the RA MPB,[12] and the IOUs suggest the RA MPB needs to be revised to address indifference.[13] But neither can point to any data or evidence other than ED's Staff Report, which itself acknowledges the limited analysis it presents is "solely for illustrative purposes" and only "largely" correct.[14] The PD should not base major changes to the MPB calculation on untested suppositions.

CUE also mistakenly concludes the PD's proposals will "directionally improve the accuracy of the RA MPB and improve customer indifference as required by law."[15] However, if the PD's proposals are adopted, the effect will be to reduce accuracy in the MPB. The PD's conclusion that there are an insufficient number of transactions to calculate the RA MPB is unsupported. As noted by others, the PD mistakenly conflates "low volume" with "unrepresentative pricing."[16] Instead, the calculation should only incorporate actual transactions under ***current*** market conditions.[17]

CUE supports adding additional years' worth of data to the MPB to "adhere as closely as possible to the current regulatory framework adopted in D.18-10-019,"[18] and claims "the valuation of RA in the MPBs should mimic ratable procurement."[19] "Ratable procurement" appears nowhere in D.18-10-019. Moreover, the fundamental point of a mark-to-market construct adopted by that decision is that the value of anything is the price it could command in the market if it were sold ***today***.[20] Attempting to mimic "ratable procurement" misrepresents the market price of attributes ***today***. The addition of stale

10 CalCCA PD Opening Comments, at 2.

11 *See* Shell PD Opening Comments, at 1 ("Fundamentally, the findings in the Proposed Decision are not supported by substantial evidence in the record."); Ava PD Opening Comments, at 3 ("There are no exigent circumstances justifying the Proposed Decision's lack of record development. Consequently, Ava recommends withdrawing the Proposed Decision and developing the record required to support MPB revisions."); *see also* PCE PD Opening Comments, at 6.

12 *See* CUE PD Opening Comments, at 4.

13 *See* Joint IOU PD Opening Comments, at 1.

14 *Energy Division Staff Report of the 2024-2025 Resource Adequacy Market Price Benchmark* (Feb. 26, 2025) (ED Staff Report), at 12.

15 *See* CUE PD Opening Comments, at 3.

16 Ava PD Opening Comments, at 6.

17 *Ibid*; *see also* CalCCA PD Opening Comments, at 8.

18 CUE PD Opening Comments, at 4.

19 *Ibid*.

20 *See* PCE PD Opening Comments, at 5.

data cannot reasonably be seen to "uphold the existing mark-to-market principles of D.18-10-019" as required by the PD.[21] As AReM/DACC notes, the addition of such data actually moves the calculation "farther away from the mark-to-market paradigm that the PD says it is trying to preserve."[22]

The PD also errs in attempting to align the data window with that used for local RA transactions because these transactions do not drive the market.[23] In fact, transactions in local RA are becoming more scarce. What are now outlier transactions should not be used to set a policy intended to be market-based. The PD's proposal for extending the lookback period should therefore be rejected. The Commission could increase the volume of transactions considered simply by collapsing the benchmarks. If after doing so the Commission remains concerned about transaction volumes, CalCCA recommend the Commission limit the timeframe as much as possible, to at its longest DACC/AReM's position.

III. THE PD RESULTS IN PROHIBITED RETROACTIVE RATEMAKING

The PD engages in prohibited retroactive ratemaking when it requires the use of a new methodology to calculate the Final 2025 RA MPB. SBUA's and CUE's opening comments repeat erroneous arguments in support of this legal error. Both parties are right to state that "general rates" cannot be applied retroactively, but they miss how the law determines when general rates are set. *Edison* is clear: if the ratesetting will be the result of a "plenary discussion" of broad policy considerations, and have a substantial impact on customers and LSEs, then "general ratemaking" occurs.[24]

SBUA commits a number of errors in stating "[t]his [Energy Resource Recovery Account (ERRA)] proceeding is a forecast rather than a true ratemaking case such as a [General Rate Case (GRC)], as noted in the [PD]."[25] The fact neither this case nor the ERRA proceeding are GRCs fails to resolve the question of whether general rates are being set. To the contrary, ERRA proceedings set PCIA rates. The Commission is decades removed from the time when it only set general rates in a GRC,[26] and the Court of Appeals found "general ratemaking" can take place outside of a GRC setting.[27] The specific proceeding at issue is not determinative. The broad policy considerations on which the PD relies, and the substantial impact the PD will have on customers and LSEs, results in "general ratemaking."

---

[21] Proposed Decision, at 18.
[22] DACC/AReM PD Opening Comments, at 9.
[23] *See* CalCCA PD Opening Comments, at 3; *see also* PCE PD Opening Comments, at 18.
[24] *Southern California Edison Co. v. Pub. Util. Comm'n*, 20 Cal.3d 813, 821, 828-829 (1978).
[25] SBUA PD Opening Comments, at 6.
[26] CalCCA PD Opening Comments, at 12 (citing to Decision 86974 (SCE's 1976 general rate case)).
[27] *Ponderosa Tel. Co. v. Pub. Util. Comm'n* (2011) 197 Cal.App.4th 48, 63-64 (finding prohibited retroactive ratemaking took place when the Commission used an 11-utility joint application to retroactively revise a ratesetting formula originally adopted in a rulemaking).

CUE errs in arguing: "the rule against retroactive ratemaking does not bar the Commission from adopting changes to a methodology for calculating pass-through *energy* costs…."[28] First, these are not pass-through energy costs. Unlike fuel expenses, the cost of utility-owned generation *capacity* recovered through the PCIA includes the IOUs' return on equity for undepreciated capital. Second, the nature of the costs at issue is only one part of a larger inquiry. What matters is whether the "business at hand" is "the application of a mathematical formula" or whether rates were set based on policy considerations.[29] The net capacity costs at issue here cannot be calculated based on "empirical data" and figures "definitively established by reference to the utilities' books."[30] The capacity costs are offset by the subjective value of the IOUs' portfolio, a value that is set by a proxy: the RA MPB. That is, unlike in *Edison*, the "truth" of the costs at issue *themselves* is in dispute. No clear, easily verifiable actual market values exist to compare to the forecasted portfolio values. This is general ratemaking. As a result, the PD engages in prohibited retroactive ratemaking when it requires the use of a new methodology to calculate the Final 2025 RA MPB.

IV. CONCLUSION

CalCCA appreciates the opportunity to submit these reply comments and requests adoption of the recommendations proposed herein.

Respectfully submitted,

Evelyn Kahl
General Counsel and Chief Policy Officer
CALIFORNIA COMMUNITY CHOICE ASSOCIATION 1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9815
E-mail: regulatory@cal-cca.org

Respectfully submitted,

Tim Lindl
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (510) 314-8385
E-mail: tlindl@keyesfox.com

Counsel for
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

June 17, 2025

---

28 CUE PD Opening Comments, at 5 (emphasis added).
29 *Edison,* at 821-829.
30 *Id.,* at 828-829.

FILED
06/18/25
04:59 PM
A2505009

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2027. (U 39 M)	Application No. 25-05-009

PROTEST OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO 2027 GENERAL RATE CASE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY

Leanne Bober
Director of Regulatory Affairs and Deputy General Counsel
Willie Calvin
Regulatory Case Manager

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone (510) 980-9815
E-mail: regulatory@cal-cca.org

Julia Kantor
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (617) 835-5113
E-mail: jkantor@keyesfox.com

On behalf of
California Community Choice Association

Dated: June 18, 2025

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2027. (U 39 M)	Application No. 25-05-009

PROTEST OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO 2027 GENERAL RATE CASE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY

Pursuant to Rule 2.6 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the California Community Choice Association[1] (CalCCA) submits this protest to the *2027 General Rate Case Application of Pacific Gas and Electric Company* (Application).[2]

Through this Application, Pacific Gas and Electric Company (PG&E) is requesting approval for recovery of projected costs through 2030 that will translate to double-digit percentage increases in customer rates over the rate case period. Moreover, PG&E's requested rate hikes would much more drastically impact PG&E's unbundled customers, with community choice aggregator (CCA) customers seeing a 23 percent increase in their rates, as compared to the 14

[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] Application (A.) 25-05-009, *2027 General Rate Case Application of Pacific Gas and Electric Company* (May 15, 2025) (Application).

percent increase imposed on PG&E's bundled customers.[3] In the context of the ongoing affordability crisis in California, it is critical that the Commission closely scrutinize both the reasonableness of PG&E's cost recovery requests and how PG&E proposes these costs be allocated across different groups of customers.

I. CALCCA'S INTEREST

CalCCA represents 24 community choice electricity providers in California, including 11 in PG&E's service territory.[4] CCA customers receive generation services from their local CCA, and receive transmission, distribution, billing, and other services from their investor-owned utility (IOU). As such, CCA customers in PG&E's service territory pay the same electric distribution, transmission, and non-bypassable charges (NBCs) as PG&E's bundled customers, including the Power Charge Indifference Adjustment (PCIA). The PCIA recovers certain generation costs from all customers, bundled and unbundled, and CCA customers are assigned to PCIA vintages in accordance with their date of departure from bundled service. Aside from NBCs like the PCIA, CCA customers pay CCA-specific generation rates, which vary and are partially influenced by local mandates to procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation.

The Commission's determinations in this proceeding on cost recovery and allocation will directly impact the rates that CalCCA members' customers pay. CCAs have an interest in ensuring the costs associated with the Application are just and reasonable as well as properly categorized to avoid illegal cost shifts between bundled and unbundled customers.[5] In particular, the CCAs have an interest in ensuring that generation costs recovered via the PCIA are assigned to the appropriate

---

[3] *See id.*, Attachment F (percentages calculated based on the increases between present rates and 2030 proposed rates across all customer classes).

[4] *See supra*, n. 1.

[5] *See infra*, Section II.A.

PCIA vintage year, as improper assignments of new investments into older vintages can result in CCA customers bearing significant costs that they did not cause PG&E to incur.

For all these reasons, CalCCA has a real, present, tangible, and pecuniary interest in PG&E's proposals in this proceeding. CalCCA is also continuing to review PG&E's Application and prepared testimony and will investigate, clarify, and possibly recommend modifications and corrections to additional proposals, positions, calculations, and issues in PG&E's Application, as they arise.

II. GROUNDS FOR PROTEST

This Application raises critical questions concerning cost shifting—*i.e.*, the recovery of costs from customers that did not cause PG&E to incur those costs. This issue continues to arise across various Commission proceedings wherein utilities propose significant new investments in their aging utility-owned generation (UOG) assets. In this case, PG&E is requesting authorization for $2.45 billion of capital investments in its UOG hydroelectric (Hydro) fleet between 2027 and 2030,[6] and for continued cost recovery of the associated annual revenue requirements for these assets from *all* customers, bundled and unbundled.[7] This proposal would result in all CCA customers bearing the costs associated with these reinvestments in PG&E's Hydro assets, even though much of this funding is going toward the relicensing of these assets at the Federal Energy Regulatory Commission (FERC) so that this aging fleet can continue to serve PG&E's bundled customers.

A. Background on PCIA Vintaging

California law prohibits cost shifts between groups of bundled and unbundled customers. In particular, Section 366.2 of the California Public Utilities Code provides that "[t]he

---

6 PG&E-5, p. 1-24.
7 *Id.*, pp. 7-22 to 7-23.

implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation."[8] Similarly, Section 365.2 mandates that the Commission ensure both that bundled customers do not experience any cost increases as a result of other customers electing to receive service from other providers, and that "departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."[9] The Commission generally refers to these requirements as a statutory mandate to ensure ratepayer indifference.[10]

The Commission's foundational policies on PCIA vintaging evolved out of these clear statutory directives prohibiting cost shifts between bundled and unbundled customers and requiring compliance with the indifference principle.[11] The Commission adopted the PCIA to ensure that when customers of IOUs depart from bundled service and receive their electricity supply from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[12] Decision (D.) 08-09-012 provides the basis for the current cost responsibility policies for departing load customers, and specifically, the policies associated with vintaging IOU generation costs. The decision limits a departing load customer's cost responsibility to resource commitments made by the IOU up until the time of the customer's departure, finding that "departing customers should bear *no* cost responsibility for . . . commitments the IOU makes after their departure."[13] This directive helps

---

8 Cal. Pub. Util. Code § 366.2(a)(4).

9 *Id.* § 365.2; *see also id.* § 366.3.

10 *See, e.g.*, Decision (D.) 16-09-044, p. 11.

11 Cal. Pub. Util. Code § 366.2(a), (f); *id.* §§ 365.2, 366.3.

12 *See* Rulemaking (R.) 17-06-026, *Scoping Memo and Ruling of Assigned Commissioner*, p. 2 (Sept. 25, 2017); D.18-10-019, p. 3.

13 D.08-09-012, p. 59 (emphasis added).

ensure that each customer will "pay its fair share of the costs the IOU incurred on [its] behalf[,]" which "is an integral part of the principles of bundled customer indifference and prevention of cost-shifting."[14]

Based on these underlying principles, unbundled customers are assigned to a vintage year based on their departure date.[15] PG&E assigns each UOG resource to a specific vintage based on the year the generation resource commitment was originally made (*i.e.*, the original date of Commission approval of UOG construction), and all ongoing costs at that facility are recorded to the same initial vintage.

The PCIA rates ultimately paid by customers are derived from the utility's Indifference Adjustment, which is updated annually in each IOU's Energy Resource Recovery Account (ERRA) forecast proceeding. The Indifference Adjustment is the difference in the target year between the cost of the IOU's supply portfolio and the market value of the IOU's supply portfolio, as shown in the graphic below.

Figure 1: Indifference Calculation

Total Portfolio Cost includes the variable power supply costs, which are also determined in the IOU's annual ERRA forecast proceedings,[16] *plus* the UOG capital investment recovery and fixed

---

[14] *Id.*, Finding of Fact (FoF) 2.

[15] *Id.*, FoF 38 and Conclusion of Law 14.

[16] Variable power supply costs include purchased power such as that from power purchase agreements (PPAs), fuel costs for UOG and PPAs with tolling agreements, and California Independent System Operator (CAISO) grid charges and revenues, net of any sales.

maintenance costs determined in a general rate case (GRC).[17]

An Indifference Adjustment is calculated for each vintage, and customers are responsible for the cumulative costs included in all vintages prior to and including their assigned vintage year.[18] The total Indifference Adjustment is collected through PCIA rates, ensuring that PG&E receives full recovery of the generation-related revenue requirement approved in GRCs and other proceedings.[19]

B. The Commission has Begun to Establish Limits on Cost Recovery from an Asset's Original Vintage Assignment Across a Range of Proceedings.

Over the past several years, a range of Commission proceedings have begun to grapple with the question of how to best ensure that the IOUs' allocation of UOG costs to CCA customers is fair and consistent with these foundational principles of cost causation underlying the Commission's PCIA policy. Specifically, these cases have focused on the cost shifting that can occur when the IOUs undertake new investments in UOG and propose to allocate all associated costs to the asset's original vintage assignment.

The problem arises when utilities undertake new investments in older UOG assets on behalf of their current bundled customers, and propose to assign *all* future costs at that facility, *even these new investments that serve only bundled customers*, to the asset's original vintage. This approach means that even when an IOU decides to significantly reinvest in an older generation asset to extend the useful life of that asset, expand the capacity of that asset, or fundamentally change the

---

17 D.11-12-018, pp. 8-9.

18 *Id.*, p. 9.

19 Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact true-up for unbundled customers. D.18-10-019 approved a true-up for the PCIA using actual recorded net costs for PCIA-eligible resources and billed revenues from both bundled and unbundled customers. This true-up now occurs via the Portfolio Allocation Balancing Account (PABA), a rolling true-up between the forecasted Indifference Adjustment and the actual costs and revenues PG&E realizes during the year related to its PCIA eligible resource portfolio.

function of the asset, *all* costs associated with these new investments are allocated to the asset's original vintage assignment. The result is that customers that have departed from bundled service remain responsible for the costs associated with any and all expansions or extensions to UOG, in perpetuity, in violation of the Commission's directive that "departing customers . . . bear no cost responsibility for . . . commitments the IOU makes after their departure."[20]

The CCAs have urged the Commission in the PCIA rulemaking and across all the IOUs' GRC proceedings to apply the Commission's foundational cost causation principles to these situations and recognize that certain types of significant new investments in UOG should be understood as *entirely new resource commitments* for purposes of PCIA vintaging.[21] This policy would be an extension of existing Commission precedent. For example, the Commission has endorsed this approach of reconsidering an asset's original vintage assignment in the context of power purchase agreement renewals/extensions and amendments.[22]

The Commission first acknowledged the validity of CCA concerns regarding the perpetual recovery of ongoing costs and reinvestments in UOG in 2018, in D.18-10-019.[23] There, the Commission found that full or partial re-vintaging may be necessary under certain circumstances. Specifically, the Commission acknowledged:

> It is possible that new investments in an old power plant may represent such a significant overhaul of the facility as to justify a "re vintaging" of the facility. Likewise, it is possible that plant investments for certain upgrades may justify a

---

20 D.08-09-012, p. 59.

21 *See* D.18-10-019, pp. 134-135; D.23-11-069, pp. 508-511; A.22-05-015, *Opening Brief of SDCP and CEA*, pp. 10-35 (Aug. 14, 2023); A.23-05-010, *Protest of CPA and CalChoice to the Application of SCE*, pp. 5-7 (Jun. 14, 2023).

22 *See* Resolution E-5095, p. 9 (Aug. 27, 2020) (approving Southern California Edison's re-vintaging of renewed contracts); Resolution E-4841, pp. 9-10 (May 11, 2017) (considering whether amendments to PPAs should result in re-vintaging, and concluding that because the amendments at issue did not affect material contract terms, such as price, re-vintaging was not appropriate (thus implying that changes to material contract terms may merit re-vintaging)).

23 D.18-10-019, p. 135.

different vintage treatment for those investments than for the underlying facility.[24] The Commission concluded that "any such analysis must be fact-specific to the plants and spending in question."[25]

CCAs' vintaging recommendations in recent GRC proceedings were responsive to this directive. In these cases, the CCAs have argued that when a utility decides to reinvest in its older UOG to extend the life, expand the capacity, or change the function of the asset, that new investment should trigger a reconsideration of the default vintage assignment for the asset.[26] When the IOU is undertaking those kinds of new investments on behalf of its bundled customers, those investments should be understood as new resource commitments for purposes of PCIA vintaging.

In response to this advocacy, in its final decision in PG&E's 2023 Phase I GRC, the Commission ordered that in future GRCs, PG&E must justify its proposed vintaging treatment for UOG whenever it proposes to undertake certain new investments—new asset life extensions, incremental capacity additions, or changed functions—in any of its UOG assets.[27] Similarly, the CCAs' arguments on these issues in San Diego Gas and Electric Company's recent GRC resulted in a Commission directive that the utility "carefully reconsider the merits of vintaging" if it decides to take on reinvestments in its UOG assets, as "such a reconsideration might be warranted."[28] These issues are still pending before the Commission in Southern California Edison Company's latest GRC.

---

24 *Id*.

25 *Id*.

26 *See* D.23-11-069, pp. 508-511; A.22-05-015, *Opening Brief of SDCP and CEA*, pp. 10-35 (Aug. 14, 2023).

27 D.23-11-069, p. 511.

28 D.24-12-074, p. 408.

C. The Commission Must Ensure That The Costs Associated With PG&E's Reinvestments In Its Aging Generation Assets Are Allocated In Line With Cost Causation.

This Application implicates these same questions regarding the appropriate vintage assignment for new utility investments in aging UOG assets. In this proceeding, PG&E is proposing to undertake $2.45 billion of capital investments in its hydro fleet between 2027 and 2030,[29] and is requesting continued cost recovery via the Legacy UOG Vintage[30] for the associated annual revenue requirements for these assets. PG&E offers many reasons why this substantial increase in investment in its Hydro assets is needed, including that it is necessary to support the relicensing process for 14 of these assets at FERC,[31] to address aging and obsolete equipment and infrastructure,[32] and to accommodate changing operational demands, which are "requiring assets to be operated differently than the modes for which they were originally designed."[33]

The Commission must closely scrutinize whether any of these proposed investments will result in a "significant overhaul" of the facilities in question such that entire facilities should be re-vintaged,[34] and/or whether any of the investments may justify a different vintage treatment for portions of facility revenue requirements.[35] Specifically, the Commission must evaluate these questions by looking to the "triggering events"[36] laid out in the 2023 GRC decision: investments that result in asset life extensions, incremental capacity additions, or changed asset functions.[37] Any such investment would represent a decision by PG&E to undertake a new generation asset

---

29 PG&E-5, p. 1-24.
30 *Id.*, pp. 7-22 to 7-23.
31 *Id.*, pp. 3-4 and 3-99.
32 *Id.*, p. 3-3.
33 *Id.*, p. 3-2.
34 D.18-10-019, p. 135.
35 *Id.*
36 PG&E-5, p. 7-22.
37 D.23-11-069, p. 511.

commitment to serve its current customer needs.

PG&E's testimony indicates that much of this new investment is attributable to PG&E's decision to relicense 14 of these assets at FERC, thereby extending the corresponding asset lives by several years, often decades.[38] This decision to pursue relicensing reflects an affirmative choice by PG&E to reinvest in its Hydro fleet—a fleet with an average age exceeding 80 years, which includes many assets that have outlived their originally expected lifespan.[39] PG&E is not required to relicense these assets. Instead of pursuing relicensing, and thus committing to any new compliance obligations and licensing requirements that FERC might impose, PG&E could sell or retire the assets. In making this choice to invest in the FERC relicensing process for these assets—and thus committing to all capital investments necessary to extend the lives of these assets as well as all ongoing operations and maintenance costs associated with the continued operation of these assets for this extended period—PG&E would be undertaking new commitments beyond those associated with the assets' original license and anticipated lifespan.

If through further investigation in this proceeding it is determined that PG&E is undertaking new generation commitments through these reinvestments in its Hydro fleet, the Commission must then examine on whose behalf PG&E is making the investments. For this inquiry, the core guiding principle is that customers should pay their "fair share of the costs the IOU incurred on [their] behalf" but should not be charged for costs *not* incurred on their behalf.[40] At the outset of this inquiry, it is important to note that generally, absent an order from the Commission that PG&E should undertake an investment to serve a specific, identified procurement need for all customers in its service territory, PG&E is only permitted to make generation asset

38 *See* PG&E-5, p. 3-30.
39 *Id.*, p. 3-3.
40 D.08-09-012, FoF 2.

investments to serve its current *bundled* customers' energy and capacity needs.

Therefore, while PG&E's testimony points to several "beneficial public values" supported by PG&E's Hydro assets,[41] these are irrelevant to the question of cost recovery and appropriate vintage assignment. The purpose of the PCIA and the vintaging regime is to ensure that when customers depart, they remain responsible for costs previously incurred on their behalf;[42] the mere fact that a resource may provide public benefits for all Californians does not mean that departed customers should forever be on the hook for paying for that resource. The relevant question, rather, is whether the utility's new investment to keep the resource in service was incurred on these departed customers' behalf.

CalCCA intends to further investigate PG&E's justifications for its proposal to continue to recover all Hydro costs via the Legacy UOG Vintage to ensure that PG&E is only charging CCA customers for costs actually incurred on their behalf, in compliance with state law.

III. CATEGORIZATION OF PROCEEDING, NEED FOR HEARINGS, AND PROPOSED PROCEDURAL SCHEDULE

CalCCA supports categorization of the proceeding as "ratesetting" and agrees hearings will be needed.[43] At this time, CalCCA does not have objections to PG&E's requested procedural schedule.

IV. COMMUNICATIONS

CalCCA consents to "email only" service and requests that the following individuals be added to the service list for A.25-05-009 on behalf of CalCCA:

---

[41] PG&E-5, pp. 7-29 to 7-31.

[42] *See* R.17-06-026, *Scoping Memo and Ruling of Assigned Commissioner*, p. 2 (Sept. 25, 2017); D.18-10-019, p. 3.

[43] Application, p. 30.

Party Representative for CalCCA:

Julia Kantor
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (617) 835-5113
Email: jkantor@keyesfox.com

Information-Only Representatives for CalCCA:

Brian Dickman
NewGen Strategies & Solutions, LLC
225 Union Boulevard, Suite 450
Lakewood, CO 80228
Phone: (303) 576-0527
Email: bdickman@newgenstrategies.net

Leanne Bober
Director of Regulatory Affairs and
Deputy General Counsel
Willie Calvin
Regulatory Case Manager
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone (510) 980-9815
E-mail: regulatory@cal-cca.org

V. CONCLUSION

For the foregoing reasons, CalCCA requests the Commission set this matter for hearing to fully examine the preliminary issues discussed above.

Respectfully submitted,

/s/ Julia Kantor
Julia Kantor
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (617) 835-5113
E-mail: jkantor@keyesfox.com

June 18, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 25-05-011 (Filed May 15, 2025)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S PROTEST TO PACIFIC GAS AND ELECTRIC COMPANY'S APPLICATION

PUBLIC VERSION

Leanne Bober
Director of Regulatory Affairs and
Deputy General Counsel
Willie Calvin
Regulatory Case Manager

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9815
E-mail: regulatory@cal-cca.org

Nikhil Vijaykar
Tim Lindl
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (408) 621-3256
E-mail: nvijaykar@keyesfox.com
tlindl@keyesfox.com

June 18, 2025

TABLE OF CONTENTS

TABLE OF AUTHORITIES

SUMMARY OF RECOMMENDATIONS

- The Commission[1] should not, in this proceeding, consider PG&E's proposal to modify its settled, Commission-approved methodology for applying banked RECs towards its Minimum Retained RPS requirement, and should direct PG&E to continue valuing any banked RECs at the RPS MPB for the Forecast year and crediting the appropriate PCIA vintage(s) for the transfer;
- The Commission should not, in this proceeding, consider PG&E's proposal to modify its RA valuation methodology for PCIA ratemaking purposes, should direct PG&E to maintain its existing practice with respect to RA valuation, and should direct PG&E to make its SoD proposal in Track Two of the PCIA OIR;
- The Commission should set the default discovery timelines for all parties to: (1) five business days prior to the Fall Update; (2) three business days after rebuttal testimony; and (3) two business days after the Fall Update is filed, with exceptions from those timelines allowed in the event that PG&E requires more time due to the number or breadth of data requests;
- The Commission should require PG&E to serve public and confidential workpapers concurrently with all supplements and updates to testimony;
- The Commission should require from PG&E a clear presentation of modifications between its Prepared Testimony and any supplemental testimony;
- The Commission should require PG&E to serve public and confidential workpapers contemporaneously with all testimony supplements and updates over the course of the proceeding;
- The Commission should categorize this Application as ratesetting;
- The Commission should set PG&E's Application for hearing; and
- The Commission should set a deadline of November 5 for comments on the Fall Update, but adopt the remainder of PG&E's proposed procedural schedule.

---

[1] Acronyms and defined terms used in the Summary of Recommendations are defined in the body of this Protest.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 25-05-011 (Filed May 15, 2025)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S PROTEST TO PACIFIC GAS AND ELECTRIC COMPANY'S APPLICATION

Pursuant to Rule 2.6 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the California Community Choice Association[2] (CalCCA) hereby protests the *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)* (Application).[3]

ERRA Forecast applications are expedited, six- and a half-month cases. These proceedings are intended to establish the utility's procurement revenue requirements and set rates—including

---

[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] Application (A.) 25-05-011, *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)* (May 15, 2025).

the Power Charge Indifference Adjustment (PCIA) rates that both bundled and unbundled customers pay—before January 1 of the next calendar year. ERRA Forecast proceedings are accelerated and focused for good reason: they put the utility in a position to timely recover its prospective procurement costs and protect customers from rate volatility. To achieve those important goals efficiently, the Commission avoids wrestling with complex policy issues in these cases—reserving those issues for rulemakings or other proceedings with longer timelines and participation by a broader set of interested stakeholders. Where parties have attempted to introduce new policy proposals in ERRA Forecast proceedings, the Commission has regularly reminded parties that these cases are not the correct venue for those proposals. The scope of ERRA Forecast proceedings is limited to ensuring the utility complies with the Commission's existing orders, rules, or policies.[4]

Despite these well-understood parameters, in its Application, PG&E introduces two major policy proposals. First, PG&E proposes to depart from its settled, Commission-approved methodology for using "banked" Renewable Energy Credits (REC) to meet its Minimum Retained Renewable Portfolio Standard (RPS) requirement. Specifically, PG&E proposes to use RECs towards its bundled customer compliance requirement without crediting the unbundled customers who originally paid for a portion of those RECs. Second, PG&E proposes a new methodology for valuing the Resource Adequacy (RA) associated with its Power Charge Indifference Adjustment (PCIA) -eligible portfolio, claiming that its proposal is necessary to reflect the Commission's Slice of Day (SoD) framework for RA compliance. Specifically, PG&E proposes to take RA from PCIA-eligible battery storage resources that is paid for in part by unbundled customers, and allow

---

[4] *See* Rulemaking (R.) 25-02-005, *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes* (Feb. 26, 2025) (PCIA OIR) ("the ERRA process itself is intended to function as an individual electric IOU's annual forecast and accounting review, not as a forum for evaluating or setting policy").

bundled customers to use that RA for their own compliance for free. These proposals continue PG&E's recent concerning pattern of seeking Commission authorization for significant policy changes to the established PCIA framework via its ERRA Forecast Application. The Commission has not reviewed or authorized either proposed methodology in any prior order, rule, or policy. Instead, this is the first time PG&E has made either proposal. PG&E's proposals are therefore plainly beyond the scope of this ERRA Forecast proceeding, and the Commission should exclude these proposals from the list of scoping issues it adopts.

Importantly, earlier this year, the Commission opened a rulemaking focused squarely on issues related to the PCIA. Track Two of the PCIA OIR offers PG&E and all parties the opportunity to introduce and evaluate PCIA-related policy proposals like the ones PG&E makes here. PG&E has not offered any compelling reason for the parties to litigate its RA valuation and banked REC proposals in this expedited proceeding.[5] Those very issues are more reasonably addressed in, and indeed are preliminarily scoped into, the PCIA OIR.[6]

In addition to their procedural deficiencies, PG&E's proposals share a common substantive flaw. Both proposals would use attributes of PG&E's PCIA resources to benefit bundled customers without appropriately conveying a proportionate share of those benefits to the departed customers

---

[5] Indeed, San Diego Gas & Electric Company has not proposed any changes to its RA valuation practices in its parallel ERRA Forecast proceeding, noting that the Commission has not authorized any changes to the PCIA RA methodology to reflect the SoD framework. *See* A.25-05-012, *Application of San Diego Gas & Electric Company (U 902 E) for Approval of its 2026 Electric Procurement Revenue Requirement Forecasts, 2026 Electric Sales Forecast, and GHG-Related Forecasts, Prepared Direct Testimony of Sheri Miller on behalf of San Diego Gas & Electric Company* (May 15, 2025), at SM-5.

[6] *See* PCIA OIR at 3 ("The objectives of this proceeding are to consider and identify reasonable improvements to existing ERRA and PCIA rules, mechanisms, and processes to ensure best practices in utility forecasting and other procurement plan activities; to identify ways to mitigate and respond to rate volatility, whether resulting from market conditions or ratemaking constructs; to best ensure indifference among bundled and departed customers; and to provide policy guidance to ensure that individual utility forecast ratemaking proceedings function as efficiently and consistently as possible."), and 24 (listing as the second issue for consideration in Track Two the need for ERRA-specific implementation guidance for RA program changes, including those related to the implementation of the SoD framework).

who pay for those resources. PG&E's proposals are therefore fundamentally unfair and violate the indifference principle that is central to the PCIA framework.

With respect to banked RECs, for example, PG&E proposes to use RECs banked in years prior to 2019 towards its bundled customer Minium Retained RPS requirement. Instead of crediting the customers (a portion of whom are now unbundled) who originally paid for those RECs at the RPS Market Price Benchmark (MPB) as required by Decision (D.) 19-10-001,[7] PG&E proposes to allow its current bundled customers to use those RECs without any credit to departed load. That proposal violates D.19-10-001, which requires PG&E to value banked RECs at the MPB in the year in which it uses those RECs, irrespective of when the REC was banked.[8] It also fails to produce a reasonable or fair outcome. That is because the departed customers, who (when they were still among PG&E's bundled customers) paid for a portion of the banked RECs PG&E now seeks to use, are denied a proportionate share of the benefits associated with those RECs. And again, no Commission decision supports, let alone directs, PG&E's proposal. In fact, D.24-08-004—which addresses banked RECs and to which PG&E cites—clarifies that the Commission has not modified D.19-10-001 to date.[9] The decision also notes that the Commission may consider the applicability of D.19-10-001 to pre-2019 banked RECs in a future rulemaking.[10]

Similarly, with respect to RA valuation, PG&E proposes to average the hourly discharge of its PCIA-eligible battery resources (a positive number) and the charging of the batteries (a negative number), resulting in offsetting positive and negative RA capacity values associated with those resources. The upshot of this methodology is that it assigns PG&E's PCIA-eligible battery

---

7 Decision (D.) 19-10-001, *Decision Refining the Method to Develop and True Up Market Price Benchmarks*, R.17-06-026 (Oct. 10, 2019).

8 *Id.* at Attachment B.

9 D.24-08-004, *Decision Denying Petition for Modification of Decision 23-06-006*, R.17-06-026 (Aug. 1, 2024), at 4-5.

10 *Id.* at 5.

resources a near-zero capacity value. PG&E's proposal essentially takes RA from PCIA-eligible battery storage resources that is paid for in part by unbundled customers and allows bundled customers to use the RA for their own compliance for free. That result is not only a striking departure from PG&E's current approach to RA valuation and fundamentally unfair, but it also fails to comport with market realities. Batteries are not free. If PG&E had to go to the market to purchase battery storage RA, it would pay a seller for that RA. No seller would allow PG&E to offset the purchase price for that RA by the cost to PG&E of charging the battery. And neither PG&E nor any seller would accept $0 for the capacity value of a battery if they were to sell that battery into the market. The same logic applies when PG&E uses a battery from its PCIA portfolio to meet its bundled customers' compliance obligations. Departed customers pay for those resources and must receive a corresponding share of the RA capacity benefits from those resources.

Beyond PG&E's banked REC and RA valuation proposals, which the Commission should not include in the scope of this proceeding, this case involves several weighty issues requiring the parties' and Commission's attention. CalCCA will investigate, clarify and possibly recommend modifications and corrections to the following additional proposals, positions, calculations and issues in PG&E's Application:

- Whether PG&E's Indifference Calculation inputs and sources are reasonable and comply with D.18-10-019[11] and D.19-10-001;
- Whether PG&E's classification and valuation of RA and RPS products in the PCIA is reasonable and in compliance with prior Commission decisions;
- Whether PG&E correctly values any transactions of Greenhouse Gas-Free (GHG-Free) large hydroelectric energy; and
- Whether PG&E's funding set-asides for the Disadvantaged Community Green Tariff (DAC-GT) program and the Community Solar Green Tariff (CS-GT) programs are consistent with the budgets requested by the particular CCAs.

---

[11] D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, R.17-06-026 (Oct. 11, 2018).

Given the significant and likely contested issues of fact PG&E's Application raises, CalCCA requests the Commission set this Application for hearing. Finally, while CalCCA is largely amenable to PG&E's proposed procedural schedule, comments on the Fall Update should be due on November 5 (rather than November 3 as PG&E proposes) to ensure parties are able to devote sufficient time to thoroughly address PG&E's Fall Update.

I. CALCCA'S INTEREST

A. CalCCA Represents the Interests of Eleven CCAs That Serve PG&E's Delivery Service Customers

CalCCA represents the interests of 24 community choice aggregators (CCA) in California, including eleven CCAs that serve PG&E's delivery service customers. Each of those CCAs is governed by a Board of Directors comprised of elected officials who represent the individual cities and counties the CCA serves, or an elected City Council. CleanPowerSF is the CCA for the City and County of San Francisco, which the San Francisco Public Utilities Commission operates. San José Clean Energy is the City of San José's CCA program, which the San José Community Energy Department administers. While CalCCA's advocacy frequently benefits both bundled and unbundled customers, the CCAs are the sole advocates for their customers and their local energy programs before this Commission.

B. CCAs Are Subject to Several Non-Bypassable Charges, Including the PCIA

CCA customers receive generation services from their local CCA and receive transmission, distribution, billing, and other services from the IOU. As such, CCA customers must pay the same electric distribution, transmission, and non-bypassable rates as the IOU's bundled customers. However, CCA customers pay CCA-specific generation rates, which vary and are partially influenced by local mandates to increase electric vehicle use, procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation, and achieve other local goals. CCA and other unbundled customers are also subject to several non-bypassable charges (NBCs), including the PCIA. As discussed below, the 2026 levels of the PCIA will be established in this proceeding.

C. CalCCA Has a Real, Direct, Tangible Material and Pecuniary Interest In the Outcome of this Proceeding

In its Application, PG&E requests the Commission:

1) Adopt the 2026 ERRA-related revenue requirements listed in its Application (and as updated in the Fall Update);
2) Adopt PG&E's forecast 2026 electric sales (as updated in the Fall Update);
3) Adopt PG&E's GHG-related revenue forecasts for 2026 (as updated in the Fall Update);
4) Approve PG&E's recorded 2024 administrative and outreach expenses of $708,000;
5) Approve PG&E's rate proposals associated with its proposed total electric procurement-related revenue requirements, including PG&E's GTSR proposal, to be effective in rates on January 1, 2026; and
6) Grant such additional relief as the Commission deems proper.[12]

Importantly, PG&E requests the Commission establish the 2026 levels of the PCIA, which, as described above, both bundled and unbundled customers pay. Moreover, as described above, PG&E proposes to significantly modify: 1) the manner in which it calculates the capacity value of certain resources in its portfolio; and 2) the manner in which it calculates the value of banked RECs it uses towards its Minimum Retained RPS requirement.[13] Both of these proposals will increase the 2026 levels of the PCIA, to the detriment of unbundled customers.

CalCCA seeks to participate in this proceeding in order to protect the interests of the CCAs it represents and the interests of those CCAs' customers, in large part because the PCIA represents a significant component of the overall rates those customers pay. Ensuring the accuracy of the

---

[12] Application at 36-38.
[13] *Id.* at 17.

PCIA and other charges CCA customers pay, planning for changes to the PCIA, and protecting customers from the rate shock that can result from those changes are core directives for all CCAs and essential for any load-serving entity (LSE). CalCCA and its members therefore have a real, direct, present, tangible and pecuniary interest in this proceeding.

II. GROUNDS FOR PROTEST

The impact of PG&E's Application on both departed and bundled customers requires scrutiny under the applicable legal standards. PG&E, as the applicant, bears the burden of proof in ERRA Forecast proceedings.[14] That burden of proof includes a burden of production, which in ERRA Forecast proceedings is a "preponderance of the evidence." [15] That means the Commission should not grant the relief PG&E requests unless a preponderance of the record evidence demonstrates PG&E has affirmatively satisfied its burden of proof with respect to that request.

CalCCA protests the Application on the grounds PG&E has made certain proposals that are beyond the scope of this proceeding, and PG&E has fallen short of meeting its burden with respect to the relief it requests. CalCCA has identified several preliminary issues in the Application that should prevent adoption of the relief PG&E requests without the Commission's further examination. These issues directly impact CalCCA's interests and are described in more detail below. With that said, CalCCA is still examining the Application, conducting discovery,[16] and

---

[14] D.12-12-030, *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety Engineering,* R.11-02-019 (Dec. 28, 2012), at 42.

[15] *See, e.g.,* D.18-01-009, *Decision Adopting Pacific Gas and Electric Company's 2018 Energy Resource Recovery Account Forecast and Generation Non-Bypassable Charges and Greenhouse Gas Forecast Revenue and Reconciliation,* A.17-06-005 (Jan. 16, 2018), at 9-10; D.15-07-044, *Order Modifying Decision (D.) 12-12-030 and Denying Rehearing, as Modified,* R.11-02-019 (July 27, 2015), at 29 (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding, but noting that the preponderance of evidence is the "default standard to be used unless a more stringent burden is specified by statute or the Courts.").

[16] As of the date this Protest was filed, CalCCA has submitted over fifty data requests to PG&E to evaluate the proposals in the Application.

communicating with PG&E to better understand and analyze the utility's requests. CalCCA reserves the right to address and protest additional issues within the scope of this proceeding as they arise through continued review, analysis, discovery and investigation of all aspects of the Application and supporting testimony.

A. Issues Beyond the Scope of this Proceeding

1. PG&E Proposes a New Banked REC Application Methodology that Departs From its Established, Commission-Approved Practice, Violates D.19-10-001, and Would Harm Customers

a. The Value of RPS-eligible Generation in PG&E's PCIA-eligible Resource Portfolio Impacts the Rates that Bundled and Unbundled Customers Pay

When calculating PCIA rates, the value of RPS-eligible generation is credited against the cost of RPS-eligible resources in the utility's PCIA-eligible resource portfolio. RPS-eligible generation PG&E retains to meet its annual RPS compliance target on behalf of bundled customers is counted as Retained RPS and valued using the RPS Market Price Benchmark (MPB). Consistent with Public Utilities Code Section 366.2(g),[17] the value of Retained RPS is credited to the PCIA so that departed load customers receive a proportionate share of the RPS benefits provided by the PCIA-eligible resources for which they continue to pay. Bundled customers pay for Retained RPS by including its value in their generation rates; *i.e.*, Retained RPS is debited to ERRA and credited out of the PCIA. In other words, bundled customers pay unbundled customers for the share of PG&E's RPS generation originally procured for unbundled customers, and the price of that

---

[17] *See* Cal. Pub. Util. Code § 366.2(g) (requiring unbundled customers receive the value of any benefits from PCIA-eligible resources "that remain with bundled customers."). The central benefit of RPS-eligible PCIA resources is the RECs they generate. As such, when a utility applies RPS-eligible generation towards bundled customer compliance, section 366.2(g) requires unbundled customers paying the costs of that generation to receive its corresponding value.

purchase is the RPS MPB. The quantity and price of Retained RPS, therefore, directly impacts the rates that bundled and departed customers pay.

b. PG&E Has Consistently Used the RPS MPB in Effect During the Forecast Year to Value the Banked RECs it Applies Towards its Minimum Retained RPS Requirement

In D.20-02-047,[18] addressing PG&E's 2020 ERRA Forecast Application (A.19-06-001), the Commission established a "Minimum Retained RPS" requirement.[19] Per that requirement, PG&E's annual RPS compliance targets serve as the minimum quantities for PG&E's annual retained RPS volumes as part of the Portfolio Allocation Balancing Account (PABA) true-up.[20] In ERRA Forecast cases, therefore, PG&E must project its RPS position in the Forecast year[21] and assess whether its RPS volumes will be equal to or greater than its applicable annual RPS target. When PG&E's projected RPS position exceeds its applicable annual RPS target, no Minimum Retained RPS entry is necessary. However, when PG&E forecasts a shortfall (*i.e.*, a lower RPS volume in the Forecast year relative to its RPS target), it must record a Minimum Retained RPS entry and may use surplus RECs generated and "banked" in prior years to eliminate the shortfall and meet its requirement.[22]

PG&E's RPS volumes have fallen short of its annual RPS targets in several recent years, in part due to the Voluntary Allocation and Market Offer (VAMO) process directed by D.21-05-

---

[18] D.20-02-047, *Decision Adopting Pacific Gas and Electric Company's 2020 Energy Resource Recovery Account Forecast and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation*, A.19-06-001 (Feb. 27, 2020).

[19] *Id*. at 13-14.

[20] *Ibid.*; *see* D.19-06-023, *Decision Approving Pacific Gas and Electric Company's 2025 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2025 Electric Sales Forecast*, R.18-07-003 (June 27, 2029) (establishing minimum RPS quantities for the 2021-2024 compliance period and thereafter).

[21] *See* A.25-05-011, PG&E Prepared Testimony at 8-16 to 8-17 (May 15, 2025) (discussing PG&E's process for determining its net physical RPS position).

[22] Starting in 2011, if a utility retained more RPS generation than was needed for RPS compliance purposes, the excess RECs were set aside, or banked, for use in a future period.

030.[23] As a result, PG&E has routinely (in 2023, 2024, and 2025) drawn from its REC bank to meet its Minimum Retained RPS requirement.

When previously banked RECs are needed to meet the minimum Retained RPS for current bundled customers, it is critical to properly value and account for those banked RECs in the PCIA so that the cost of bundled customer compliance is not shifted to departed load customers. In 2023, 2024, and 2025, PG&E has consistently valued and accounted for its banked RECs in the correct manner. When PG&E has drawn from its "bank" to meet its Minimum Retained RPS requirement—irrespective of whether the banked REC it used was generated and banked before or after 2019—it has correctly priced the REC transfer at the RPS Adder applicable *in the year of the transfer* and credited the corresponding PCIA vintage(s).[24] This approach correctly applies D.19-10-001, which requires all RECs forecasted to be used towards bundled customer compliance in any given year to be valued at the RPS benchmark and credited to the PCIA.[25]

The logic underlying PG&E's settled methodology is sound. The set of bundled customers who originally paid for the banked RECs (in the year those RECs were generated and originally retained for bundled customer compliance), and the set of bundled customers who subsequently use those RECs (when PG&E applies the RECs towards its Minimum Retained RPS requirement)

---

23 *See* A.24-02-012, PG&E Prepared Testimony at 12-8 (Feb. 28, 2024) (PG&E 2024 Compliance Prepared Testimony); *see also* A.25-02-013, PG&E Prepared Testimony at 12-8 (Feb. 28, 2025) (PG&E 2025 Compliance Prepared Testimony). Note that in each of these cases, PG&E explains that its net physical RPS position was less than its annual RPS target during the compliance period, and that PG&E therefore recorded a monthly minimum RPS entry in 2023 and 2024). *See also* A.24-05-009, PG&E Rebuttal Testimony at 17 (May 15, 2024) (forecasting a REC shortfall).

24 *See* PG&E 2024 Prepared Testimony at 12-8 (stating "The Minimum RPS units are valued at the [2023] market price benchmark"); PG&E 2025 Prepared Testimony at 12-8 (stating that PG&E would record an entry at the 2024 RPS Adder to meet its net short RPS position); D.24-12-038, *Decision Approving Pacific Gas and Electric Company's 2025 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2025 Electric Sales Forecast*, A.24-05-009 (Dec. 19, 2024), at 16-17 (noting that PG&E anticipated using RECs generated and banked in 2018, and possibly in 2020, to meet its forecast REC shortfall in 2025, and would value any 2018 and 2020 banked RECs that it used in 2025 at the 2025 RPS Adder).

25 *See* D.19-10-001 at Attachment B.

are not the same set of customers. That is because a portion of the former set of bundled customers is now departed load. Thus, to ensure fairness and indifference, the original customers must be credited for the banked REC transfer while the current customers are charged for that transfer (at the RPS Adder). They must be paid today's market value for the RECs bundled customers will use today. The Commission has, on multiple occasions, approved PG&E's banked REC methodology.[26]

The Table[27] below describes the banked REC volumes PG&E has used in prior years, including the years in which those banked RECs were generated and used, respectively.

PG&E's Use of Banked RECs in Prior Years

	ERRA Test Year		
	2023	**2024**	**2025**
Banked RECs Needed for Minimum RPS	**3,997,503**	**5,745,659**	[redacted]
Value Applied to Banked RECs	2023 RPS Adder	2024 RPS Adder	2025 RPS Adder
Banked REC Year Used			[redacted]
2018		(3,020,978)	[redacted]
2019			[redacted]
2020			[redacted]
2021	(3,211,076)	(2,188,656)	[redacted]
2022	(786,427)	(536,025)	[redacted]
2023			[redacted]
2024			[redacted]
2025			[redacted]
Banked RECs Used	**(3,997,503)**	**(5,745,659)**	[redacted]

26 *See* D.22-12-044, *Decision Adopting the Electric Revenue Requirements and Rates Associated with the 2023 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation and the 2023 Electric Sales Forecast for Pacific Gas and Electric Company*, A.22-05-029 (Dec. 15, 2022), at OP 1; D.23-12-022, *Decision Adopting the Electric Revenue Requirements and Rates Associated with the 2024 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation and the 2024 Electric Sales Forecast for Pacific Gas and Electric Company as Well as the Resolution of the 2023 Trigger Application for an Undercollection of the Energy Resource Recovery Account*, A.23-05-012, and A.23-07-012 (Dec. 14, 2023), at OP 1, and D.24-12-038, at COL 1 (approving PG&E's banked REC application methodology for the purposes of its 2023, 2024 and 2025 ERRA Forecasts).

27 PG&E Workpaper 08. ERRA_2026_Forecast_WP_PGE_20250515_Tables_8-2_8-3_8-4_CONF, tab 'Applied_Historical'.

c. PG&E Proposes to Depart from Its Commission-Approved Banked REC Application Methodology and Apply a New Methodology that Violates D.19-10-001

In 2026, like in 2023, 2024, and 2025, PG&E forecasts a short RPS position and expects to use banked RECs in order to meet its Minimum Retained RPS requirement.[28] PG&E proposes to first use RECs generated banked in and after 2019 (post-2019 banked RECs) towards its Minimum Retained RPS requirement.[29] Once those banked RECs are exhausted, and to the extent a shortfall persists (which PG&E anticipates it will), PG&E proposes to then use RECs generated and banked *before* January 1, 2019 (pre-2019 Banked RECs) to meet its Minimum Retained RPS requirement.[30] This approach—starting with applying post-2019 banked RECs before applying pre-2019 banked RECs—is consistent with D.23-12-022.[31]

PG&E departs from its Commission-approved methodology, however, when it invents a distinction between the ratemaking treatment that must be applied to pre-2019 versus post-2019 banked RECs. PG&E proposes to continue applying the applicable current RPS adder to credit customers based on their PCIA vintage *only when using post-2019 banked RECs.*[32] When using pre-2019 banked RECs, PG&E effectively proposes to assign <u>no value</u> to the banked REC transfer. PG&E will make offsetting debit and credit entries in the 2026 PCIA vintage, but will not credit the departed customers who originally paid for the RECs PG&E now seeks to use towards bundled customer compliance.[33] That is, PG&E proposes not to pay unbundled customers for the RECs bundled customers will use.

---

28 *See* PG&E 2025 Prepared Testimony at 8-19.
29 *Ibid.*
30 *Ibid.*
31 *See* D.23-12-022 at 17.
32 *See* PG&E 2025 Prepared Testimony at 8-19.
33 *Ibid.*

PG&E's proposal violates D.19-10-001, which requires <u>all RECs</u> forecasted to be used towards bundled customer compliance in any given year to be valued at the RPS benchmark and credited to the PCIA.[34] That requirement applies to all Forecast Retained RPS. Decision 19-10-001 does not draw any distinction between the treatment of pre-2019 and post-2019 banked RECs. In other words, irrespective of when a REC was generated, and irrespective of whether any customer previously paid for that REC, D.19-10-001 requires that REC be valued at the benchmark. That outcome is consistent with Public Utilities Code section 366.2(g), which requires unbundled customers receive "the value of any benefits that remain with bundled service customers."[35]

PG&E argues that D.19-10-001 defines applicable RECs as "RECs generated commencing January 1, 2019, and going forward"[36] and excludes pre-2019 banked RECs "from receiving any additional ratemaking treatment associated with bundled RPS compliance."[37] PG&E is incorrect and misapplies D.19-10-001. Nothing in D.19-10-001 (or any other Commission decision) establishes a January 1, 2019 "effective date" with respect to the valuation of banked RECs used to meet the utility's Minimum Retained RPS requirement.

The January 1, 2019 "effective date" in D.19-10-001 arises in the context of a wholly separate issue: the valuation of Unsold RPS. In D.19-10-001, the Commission departed from its prior practice of requiring the valuation of all RECs in the year they are generated, and assigned Unsold RPS zero value for PCIA ratemaking purposes (until they are used for bundled customer compliance), provided those RECs were generated after December 31, 2018.[38] PG&E's proposal

---

34 *See* D.19-10-001 at Attachment B.
35 Cal. Pub. Util. Code § 366.2(g).
36 *See* PG&E 2025 Prepared Testimony at 8-18 (citing D.19-10-001, Finding of Fact 8).
37 *See id*. at 8-18 to 8-19.
38 *See* D.19-10-001 at 35; OP 3b.

to lift this effective date from the valuation of Unsold RPS and apply it to the valuation of banked RECs has no basis in D.19-10-001, or any other Commission decision.

d. Valuing Banked RECs At the RPS MPB in the Year the Banked RECs are Used Towards Bundled Customer Compliance and Crediting the PCIA is Not Only Consistent with State Law and Commission Precedent but Also Produces a Fair Outcome

Under PG&E's current methodology, departed customers receive credit for the value of RECs counted as Retained RPS on behalf of current bundled customers, leaving the departed customers indifferent relative to current bundled customers. Bundled customers that only paid a portion of the cost of the RECs in a prior year pay the rest of the cost of those RECs when they are needed for compliance. Departed customers that paid the other portion of the cost of the same RECs (when they were bundled customers) are paid back.

This equation bears repeating. For example, banked RECs from 2018 were paid for by customers who were bundled in 2018. But many of those customers have since departed PG&E's bundled service. Those now-departed, previously-bundled customers should not be required to subsidize the cost of PG&E's RPS compliance on behalf of today's bundled customers. It is fundamentally unfair for PG&E to use RECs that were paid for by now-departed customers without crediting those customers.

A hypothetical example helps illustrate this point. Assume Alice, John, and Darcie buy six apples together, with each of them paying one third the cost of the apples. A week later, Darcie and John promise to bake a pie for a vendor at the farmers market and use all six of the apples to bake the pie. Darcie and John provide the pie to the vendor to meet their obligation, who pays them for their pie. However, Darcie and John refuse to give Alice any of the proceeds from the vendor. Clearly, the fairest result here is that Darcie and John should pay Alice back for the value of the apples Alice paid for (one third the cost of the six apples). Under PG&E's proposed modification to its banked REC application methodology, Darcie and John can simply walk away with Alice's contribution to the value of the pie without paying her back. That result is clearly unfair.

e. PG&E's Proposal is Beyond the Scope of this ERRA Forecast Proceeding as it Modifies a Methodology Approved in Multiple Commission Decisions and Does Not Implement a Commission-Approved Methodology

As PG&E and the other utilities have reminded stakeholders time and again, the purpose of ERRA Forecast dockets is to assure timely recovery of the utilities' actual electric procurement costs, as required by Public Utilities Code Section 454.5(d)(3), among other Commission decision-mandated tasks. The approval of program costs, the appropriate rate mechanisms to recover those costs, and the allocation of those costs among different customer groups is pre-determined via authorizing Commission decisions in other proceedings including the utility's general rate case. The scope of ERRA Forecast proceedings is limited to evaluating the IOUs' compliance with prior Commission orders, rules or policies.[39]

The Commission has largely forbidden policymaking in ERRA Forecast cases unless a prior Commission decision has ordered such policymaking.[40] For example, the Scoping Memo in A.24-05-009 (PG&E's 2025 ERRA Forecast application) rejected the inclusion of PG&E's proposal to artificially cap the System Resource Adequacy (RA) Market Price Benchmark in the scope of the proceeding, stating:

> The Commission acknowledges that the RA MPB Issue may merit additional consideration in a rulemaking. Nonetheless, we are persuaded by CalCCA and DACC that this proceeding is the incorrect venue to address these issues, given the clear direction in prior decisions regarding the ratemaking calculation methodologies that shall be applied in ERRA forecast applications, and given the

---

39 *See, e.g.*, A.13-05-015, *Scoping Memo and Ruling of Assigned Commissioner* at 4 (Sept. 12, 2013).

40 *See, e.g.,* D.18-01-009 at 10 (finding that policy issues are properly addressed in other dockets); *see also id.* at 14, COL 2 and OP 2 (denying PG&E's request to modify its line loss calculation).

> expedited schedule and record development needed to reach resolutions for these matters.[41]

Similarly, A.17-06-005 (PG&E's 2018 ERRA Forecast application) rejected the inclusion of certain CCA-proposed changes to the PCIA ratemaking methodology, stating:

> The CCA parties are proposing changes to existing methods of calculation, and do not allege non-compliance with Commission rules, decisions, and resolutions on the part of PG&E. Such proposals should be addressed in proceedings with input from other investor-owned utilities and interested parties.[42]

Fairness requires the Commission similarly prohibit consideration of PG&E's new banked REC application methodology in this proceeding. Notably, as the Scoping Memo in PG&E's 2025 ERRA Forecast application noted in the context of PG&E's policymaking proposal in that case, multiple prior Commission decisions give PG&E clear direction with respect to the banked REC application methodology that must be applied in ERRA Forecast proceedings:

- D.19-10-001 requires all RECs forecasted to be used towards bundled customer compliance in any given year be valued at the RPS benchmark applicable in that year, and credited to the PCIA.[43]
- D.22-12-044 and D.23-12-022 approved PG&E's practice of valuing banked REC transfers at the RPS benchmark applicable in the Forecast year, including pre-2019 banked RECs.[44]
- D.23-06-006 confirmed the ratemaking treatment of banked RECs established in D.19-10-001.[45]

And, contrary to PG&E's argument, nothing in D.24-08-004 (resolving Southern California Edison's petition for modification of D.23-06-006) *modified* PG&E's banked REC application

---

41 A.24-05-009, *Assigned Commissioner's Scoping Memo and Ruling* at 3 (Aug. 1, 2024) (citations omitted).

42 A.17-06-005, *Scoping Memo and Ruling of Assigned Commissioner* at 3-4 (Aug. 24, 2017).

43 *See* D.19-10-001 at Attachment B.

44 *See* D.22-12-044 at OP 1; D.23-12-022 at OP 1.

45 *See* D.23-06-006, *Decision Addressing Greenhouse Gas-Free Resources, Long-Term Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access*, R.17-06-026 (June 8, 2023), at 44.

methodology approved in D.23-12-022.[46] In fact, that decision confirms that nothing in D.23-06-006 modifies D.19-10-001, and declines to conclude (as SCE had requested) that the ratemaking treatment prescribed by D.19-10-001 applies only to banked RECs generated in or after 2019.[47] Moreover, D.24-08-004 expressly states that parties' perspectives on the applicability of D.19-10-001 to RECs generated and banked before 2019 were not fully evaluated in that Decision, and noted that the Commission "may consider the issue in a future rulemaking."[48]

PG&E may wish the Commission had adopted SCE's proposed approach to the valuation of pre-2019 banked RECs in D.24-08-004, but the Decision does not do so. On the contrary, it expressly maintains that D.19-10-001 continues to control this issue, just as it has controlled in prior years when PG&E applied the RPS MPB to credit the PCIA for the transfer of both pre- and post-2019 banked RECs. In short, controlling Commission precedent (D.19-10-001) has not been modified. Therefore, PG&E's proposal to implement a new banked REC application methodology is plainly beyond the scope of this ERRA Forecast proceeding (which, again, is limited to applying existing Commission decisions, not creating new policy).

Further, as the IOUs have argued previously, dockets like rulemakings and consolidated applications apply to all California utilities and are noticed to, and generally include as parties, a broader set of stakeholders.[49] Proposals to change PG&E's settled banked REC application methodology, therefore, can and should be raised in those types of dockets, such that all interested parties have an opportunity to evaluate and respond to those proposals. It is unlikely all parties with an interest in PG&E's banked REC application methodology have notice of it being raised

---

46 *See* PG&E 2025 Prepared Testimony at 8-19.

47 *See* D.24-08-004 at 5.

48 *Ibid.*

49 A.18-06-001, *PG&E Reply to Protests and Responses* at 2-3 (Jul. 16, 2018) (addressing rulemakings).

here. In contrast, should the Commission consider the applicability of D.19-10-001 to pre-2019 RECs in a rulemaking (which D.24-08-004 suggests it might), a far broader set of parties would have a meaningful opportunity to weigh in.

PG&E itself has represented to the Commission the narrow and ministerial scope of ERRA Forecast applications—and how narrow it should be going forward. In Rulemaking (R.) 17-06-026, the Commission sought input into a change in the schedule for the ERRA Forecast proceedings that would replace the November Update with an October Update.[50] CalCCA argued this change should be accompanied by a corresponding change to the filing date of the IOUs' ERRA Forecast applications in order to largely maintain the same pre-Update timeline for parties to understand and develop a robust record.[51] PG&E disagreed, arguing ERRA Forecast proceedings do not include the type of policymaking that require substantial record development: "The existing schedule (*i.e.*, from June 1st to early November) is more than sufficient to litigate *what are mostly routine and non-controversial* non-Update-related aspects of the Joint Utilities' ERRA Forecast proceedings."[52] PG&E also stated it agreed with comments from another party that the ERRA Forecast proceedings "by design" should consist of "perfunctory updates."[53] It also observed that complications surrounding the Fall (at the time, November) Update were likely indicative of "growing pains" associated with the new PCIA methodology and not indicative of what it called "*routine review* of the ERRA Forecast applications."[54] PG&E also agreed that future

---

50 R.17-06-026, *E-Mail Ruling Requesting Comments on ERRA Timing Proposal* at 5 (May 20, 2021).

51 R.17-06-026, *California Community Choice Association's Comments in Response to Staff's ERRA Timing Proposal* at 4-12 (June 15, 2021).

52 R.17-06-026, *The Joint Utilities' Opening Comments on Proposed Decision Resolving Phase 2 Issues Related to Energy Resources Recovery Account Proceedings* at 6 (Jan. 6, 2022) (emphasis added).

53 R.17-06-026, *Reply of Southern California Edison Company (U 338-E) to Administrative Law Judge's Ruling Requesting Comments on the Market Price Benchmark Issue Date* at 5 (Sept. 22, 2021) (emphasis added).

54 *Id*. (emphasis added).

ERRAs, including this 2025 ERRA Forecast, should "be *more routine* than have been experienced in the past two or three years."[55] PG&E should not be allowed to now distance itself from its own prior statements to push through approval of a massive change to the PCIA ratemaking framework through what PG&E itself describes as a "routine" and expedited proceeding.

Importantly, there is simply no room to consider a new banked REC application methodology in a six-and-a-half-month proceeding. Stakeholders lack sufficient time and resources to track down all of the answers to the thorny legal, policy and ratemaking questions that PG&E's proposal implicates. CalCCA has endeavored since PG&E filed its Application to find a way to evaluate the details of PG&E's proposal in time for intervenor testimony (including by issuing over fifty discovery requests to date). However, CalCCA is unlikely to be able to thoroughly examine PG&E's proposal within the brief timeframes required for this proceeding. It is therefore neither reasonable nor practical for PG&E's banked REC application proposal to enter the scope of this proceeding. Accordingly, the Commission should exclude it from scope.

To the extent PG&E wishes to propose its new banked REC application methodology in a separate proceeding, it should raise that methodology in the PCIA OIR. There, parties have raised the issue of the application and valuation of banked RECs.[56] PG&E will have the opportunity to raise its banked REC proposal for consideration in Track Two of that OIR. That proceeding gives the Commission a better forum to develop a record on PG&E's proposal, resolve legal questions that affect all three IOUs (such as, for example, the correct interpretation of D.19-10-001 and D.24-08-004) and achieve consistency across all three IOUs' banked REC application practices.

---

55 *Id*.

56 R.25-02-005, *California Community Choice Association's Opening Comments on The Order Instituting Rulemaking and Energy Division Staff Report* at 35 (Mar. 18, 2025).

f. The Commission [redacted]

Not only is PG&E's proposal to use pre-2019 banked RECs without crediting the now-departed customers who paid for those RECs contrary to Commission precedent, fundamentally unfair, and beyond the scope of this proceeding, it is also [redacted] PG&E proposes to use those volumes *only* after it exhausts all banked RECs (including pre-2019 banked RECs),[57] but it does not justify its baseless distinction between Unsold RPS and banked RECs, nor can it point to any Commission decision requiring PG&E to use banked RECs before using Unsold RPS. PG&E forecasts a [redacted] MWh Minimum Retained RPS Entry in 2026,[58] and has a total of 3,758,559 MWh of Unsold RPS across 2023 and 2024;[59] [redacted]

2. PG&E's Proposal to Change its Calculation of the RA Value of its PCIA-Eligible Portfolio is Conceptually Flawed, Biased in Favor of Bundled Customers, and Beyond the Scope of This Proceeding

a. PG&E Proposes to Modify the Manner in Which it Calculates its PCIA Portfolio's Capacity Value to Reflect the Implementation of the SoD Framework

The Commission's RA program, created in 2004, requires that each load serving entity (LSE) maintain physical generating capacity and electrical demand response to meet its respective

57 PG&E 2025 Prepared Testimony at 8-19.
58 *Id.* at Table 8-4.
59 *Id.* at Table 8-2.

load requirements on an annal basis.[60] That program underwent changes in 2022, when the Commission established a new SoD framework for the RA program.[61] Under the SoD framework, each LSE must show sufficient capacity to meet 24 separate hourly RA requirements across each month of the year. The new SoD RA compliance requirements became fully operational on January 1, 2025.

In this proceeding, PG&E proposes to change the way it calculates the capacity value of certain resources in its PCIA-eligible portfolio to account for the implementation of the Commission's SoD RA compliance program (*i.e.*, a methodology to translate SoD volumes into single monthly values that are needed to integrate with the currently established PCIA and related cost recovery revenue requirement calculations). While the details of PG&E's convoluted proposal are complex, at a high level, PG&E proposes to:

1. Calculate its RA open position before factoring in energy storage;
2. Generate a charge/discharge profile for its aggregate energy storage supply that spans the 24 hourly slices;
3. Add the resulting charge and discharge hourly profile to the initial open position developed in step 1 to generate a storage-adjusted open position; and
4. Account for estimated unsold RA capacity from the storage-adjusted open position for hours projected to have excess supply.[62]

PG&E then proposes to translate the resulting 24-hour SoD positions in each month into single monthly positions by simply averaging the hourly generation profile of each resource, applying hourly weighting factors from the California Energy Commission's (CEC) hourly system load forecast.[63]

---

[60] *Id.* at 4-10.
[61] D.22-06-050, *Decision Adopting Local Capacity Obligations for 2023-2025, Flexible Capacity Obligations for 2023*, R.21-11-002 (Jun. 24, 2022).
[62] *See* PG&E 2025 Prepared Testimony at 5-11 to 5-12.
[63] *Id.* at 5-12.

PG&E's proposal raises at least two concerns. First, as PG&E acknowledges in its Application, changes to the valuation of RA for PCIA ratemaking purposes resulting from the implementation of the SoD framework may soon be considered in the new PCIA OIR.[64] Indeed, these policy proposals *should* be made and considered in the PCIA OIR, and not in this expedited ERRA Forecast proceeding, the purpose of which is to establish procurement revenue requirements for 2026 ratesetting by implementing existing Commission decisions. Whereas PG&E's current approach to RA valuation—which relies on the "Net Qualifying Capacity" (NQC) of the resources in its electric supply portfolio—is based on over a decade of Commission precedent, no prior Commission decision, rule or policy directs PG&E to implement the RA valuation methodology it proposes here.

Second, PG&E's proposal is fundamentally flawed because it implies that storage resources are free, which they are not. To the extent the Commission considers PG&E's proposal in this proceeding (which it should not), the Commission should not permit PG&E to implement a methodology that does not comport with market realities and produces the absurd result of a near-zero RA capacity value for its PCIA-eligible battery resources.

b. PG&E's RA Valuation Proposal Should Be Excluded from the Scope of this Proceeding and Addressed in Track Two of the PCIA OIR

As this Protest explains at length above, the scope of ERRA Forecast proceedings is limited to evaluating the IOU's compliance with prior Commission orders, rules or policies. These proceedings are neither an appropriate nor practical forum for policymaking. Like its proposal to implement a new banked REC application methodology, PG&E's RA valuation proposal is an

[64] *See* Application at 26.

example of the kind of policymaking that is well-beyond the scope of an ERRA Forecast proceeding.

PG&E's current approach to RA valuation is based on the NQC of the resources in its electric supply portfolio. The Commission authorized an NQC-based approach over a decade ago.[65] The Commission then affirmed the use of NQC in D.18-10-019, in which it noted that the value of utilities' capacity resources should be determined by accounting for resource NQC.[66] The Commission further affirmed the use of NQC in D.19-10-001—in which the Commission ruled that the utilities' Forecast Retained RA must be based on the final NQCs of the IOUs' PCIA-eligible generation resource portfolio.[67] In stark contrast with the settled RA valuation approach directed by these Commission decisions, no prior Commission decision, rule or policy directs PG&E to implement the novel RA valuation approach it proposes here. The Commission should therefore exclude PG&E's proposal from the scope of this proceeding.

Proposals to revise the PCIA methodology to reflect SoD can and should be made in the PCIA OIR (R.25-02-005). The preliminary scope of Track Two of the PCIA OIR specifically includes the following issue: "Consideration of the need for ERRA-specific implementation guidance for RA program changes, including those related to the implementation of the Slice of Day framework, as was raised in the 2025 ERRA forecast."[68] There is simply no reason for the Commission to consider an SoD RA valuation proposal in this expedited ERRA Forecast proceeding when it is likely to consider this very issue in the near future in the PCIA OIR.

The benefits of considering SoD RA valuation methodologies in the PCIA OIR, rather than in the IOUs' ERRA Forecast proceedings, are two-fold. First, the Commission can more efficiently

---

65 *See* D.11-12-018, *Decision Adopting Direct Access Reforms,* R.07-05-025 (Dec. 1, 2011), at OP 8.
66 *See* D.18-10-019 at OP 1, OP 2, COL 4, Appendix 1.
67 *See* D.19-10-001 at OP 2, Attachment B, Table II.
68 *See* PCIA OIR at 24.

achieve consistency across IOUs via a rulemaking. There is no reason for each IOU to modify its PCIA methodology in different manners to reflect the SoD RA compliance framework. The simplest way for the Commission to ensure consistent practices will be to adopt the same RA valuation methodology for all three IOUs, and the easiest way to ensure it adopts the same methodology for all three IOUs is to consider the issue in a proceeding in which all three IOUs are parties (*i.e.*, the PCIA OIR).

Second, a rulemaking affords the Commission the time to consider this issue holistically and assess potential changes to both components of the RA valuation equation: quantity and price, to reflect the new SoD framework in a manner that is fair and ensures indifference. Addressing either component (quantity or price) in a vacuum is suboptimal and could lead to distorted calculations of the value of the IOU's PCIA-eligible portfolio. PG&E's proposal in this proceeding, for instance, addresses only the quantity side of the equation. A holistic examination would evaluate changes to quantity and price components in tandem.

Moreover, PG&E has not presented any compelling need for the Commission to address the SoD framework in this proceeding rather than addressing it in the PCIA OIR. On this point, SDG&E's approach to the same issue is instructive. SDG&E does not propose any change to its RA valuation practices in its pending, parallel 2026 ERRA Forecast proceeding. In testimony, SDG&E witness Miller observes:

> D.22-06-050 adopted a 24-hour slice of day ("SOD") approach to RA program requirements. At the time of this May filing, no changes to the PCIA RA methodology for SOD have been approved by the Commission. SDG&E is therefore making no such changes to the PCIA methodology for RA in this filing, and the methodology is consistent with prior years' filings.[69]

---

[69] A.25-05-012, *Application of San Diego Gas & Electric Company (U 902 E) for Approval of its 2026 Electric Procurement Revenue Requirement Forecasts, 2026 Electric Sales Forecast, and GHG-*

SDG&E witness Miller is correct. The Commission has not issued any decision, rule or policy making changes to the PCIA RA methodology to reflect the SoD RA compliance framework (although it is likely to do so in the near-term in the PCIA OIR). PG&E's proposal is therefore premature and misplaced. Allowing that policy proposal to enter the scope of this proceeding would needlessly require parties to spend significant resources in an already-compressed proceeding, evaluating and addressing a proposal which will almost certainly be displaced when the Commission takes this issue up in a separate proceeding.

Finally, CalCCA acknowledges the Commission adopted an interim SoD RA valuation methodology for Southern California Edison Company (SCE) in D.24-12-039 (resolving SCE's 2025 ERRA Forecast case).[70] Putting aside the question of whether that methodology was properly included in the scope of SCE's 2025 ERRA Forecast proceeding,[71] SCE made its proposal at a time when the Commission did not have any other obvious proceeding in which to consider revisions to the PCIA RA valuation methodology. Therefore, while it adopted SCE's interim SoD RA valuation proposal, D.24-12-039 specifically did so for the limited purpose of SCE's 2025 ERRA Forecast. The Commission acknowledged that "[t]he issues of whether hourly RA MPB prices are needed and how to achieve proper accounting for storage and hybrid resources under SOD are both ripe for consideration in a rulemaking proceeding."[72] Since that Decision was issued, the Commission has initiated the very rulemaking that D.24-12-039 contemplates (*i.e.,* the PCIA OIR), and as such, the circumstances that existed when SCE made its interim SOD RA valuation proposal no longer exist. Therefore, again, there is simply no reason for the Commission to

Related Forecasts, Prepared Direct Testimony of Sheri Miller on behalf of San Diego Gas & Electric Company at SM-5 (May 15, 2025).

70 *See* D.24-12-039, *Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue Requirement*, A.24-05-007 (Dec. 19, 2024), at 75.

71 CalCCA objected to the inclusion of SCE's interim SOD RA valuation proposal in A.24-05-007.

72 *See* D.24-12-039 at 75.

consider a separate, interim SOD RA valuation proposal in this proceeding—including one that diverges significantly from SCE's interim methodology—when it is likely to consider this very issue in the near future in a pending rulemaking.

c. PG&E's Proposal Produces the Absurd Result of a Near-Zero RA Capacity Value for its PCIA-Eligible Battery Resources

Putting aside the procedural deficiencies with PG&E's proposal, one fundamental, substantive flaw is the treatment of the capacity that PG&E's PCIA-eligible battery storage resources contribute towards bundled customer compliance. Under PG&E's proposed methodology, an algorithm allocates PG&E's available battery storage RA charging and discharging capacity across all 24 hours of every month in a manner that seeks to minimize PG&E's SoD RA open position across all hours.[73] When translating the hourly generation profiles to a monthly average for the PCIA, PG&E averages the discharge of PG&E's battery resources (a positive number) and the charging of the batteries (a negative number), resulting in offsetting positive and negative RA capacity values associated with those resources. The upshot of this approach for PG&E is that it assigns PG&E's PCIA-eligible battery resources a near-zero capacity value, because it offsets PG&E's *discharge* of battery resources during the hours in which it has an open RA position by the *charging* of those resources during other periods. PG&E carries this near zero capacity over into the PCIA template where the RA MPB is multiplied by RA quantity to determine the dollar value bundled customers will be required to pay to retain the RA for compliance purposes. PG&E's proposal essentially takes RA from PCIA-eligible battery storage resources that is paid for in part by unbundled customers and allows bundled customers to use the RA for their own compliance for free.

---

[73] *See* PG&E 2025 Prepared Testimony at 5-9.

PG&E's approach, and the result it produces, does not comport with market realities or even basic logic. If PG&E had to go to the market to purchase battery storage RA, it would pay a seller for that RA. No seller would allow PG&E to offset the purchase price for that RA by the cost to PG&E of charging the battery and receive the RA for free. PG&E should not be permitted to value the RA it retains for bundled customer compliance in a manner that implies that batteries are free simply because it must use its excess PCIA portfolio to charge its batteries. In this context, PG&E's batteries provide a *capacity* product, not an *energy* product, and thus, discounting their discharge value by the cost of charging is illogical. Put another way, unlike other generation resources, the value of batteries is their ability to shift load (charge at one time, and discharge at a different time) and thereby make capacity available when needed. That means PG&E should therefore pay for RA when both charging *and* discharging batteries—not offset the value of battery discharge by its hourly charging. If PG&E were to meet its RA needs for certain hours with any other supply resource (for example, a baseload resource), it would pay for that resource and value it in the PCIA. PG&E would have no opportunity to offset the value it received during those hours with costs from other hours. There is no reason why batteries should be treated any differently. To the extent the Commission includes PG&E's proposal in the scope of this proceeding, which it should not, CalCCA will continue to examine that proposal via discovery and further address the merits of PG&E's proposal via testimony and briefing.

B. Issues Within the Scope of this Proceeding

CalCCA hopes to work with PG&E over the course of this proceeding to review PG&E's workpapers and better understand, investigate, and potentially submit testimony regarding various in-scope components of the Application, including but not limited to:

- Whether PG&E's Indifference Calculation inputs and sources are appropriate and comply with D.18-10-019 and D.19-10-001;

- Whether PG&E's classification and valuation of RA and RPS products in the PCIA is reasonable and in compliance with prior Commission decisions;
- Whether PG&E correctly values any transactions of GHG-Free large hydroelectric energy; and
- Whether PG&E's funding set-asides for the DAC-GT program and the CS-GT programs are consistent with the budgets requested by the particular CCAs.

CalCCA is still examining the Application and reserves the right to address and protest additional issues in the course of this proceeding as they arise through further review, analysis, discovery and investigation of all aspects of the Application.

III. CATEGORIZATION OF PROCEEDING, NEED FOR HEARINGS, SCOPE OF ISSUES, AND PROPOSED PROCEDURAL SCHEDULE

A. CalCCA Agrees this Proceeding Should Be Categorized as "Ratesetting"

PG&E proposes to categorize this proceeding as a ratesetting proceeding within the meaning of Rule 1.3(g) of the Commission's Rules of Practice and Procedure.[74] CalCCA agrees with the categorization of this proceeding as ratesetting.

B. CalCCA Believes Hearings May Be Necessary

PG&E states the need for hearings in this proceeding and the issues to be considered in hearings will depend on the degree to which other parties contest PG&E's requests.[75] As this Protest makes plain, CalCCA contests several of PG&E's requests, and may contest additional requests as it continues to review PG&E's Application. While CalCCA will pursue settlement and record stipulations to the extent feasible, PG&E's proposed procedural schedule appropriately assumes hearings may be necessary. The Commission should reserve a date for an evidentiary hearing to address unresolved issues of fact.

---

[74] *See* Application at 30.
[75] *See id.* at 30.

C. The Commission Should Not Consider PG&E's RA Valuation or Banked REC Proposals Proposal in the Scope of this Proceeding

As CalCCA describes at length above, PG&E's proposal to depart from its established, Commission-approved methodology when applying banked RECs towards its Minimum Retained RPS requirement, as well as its proposal to slash the RA value of its storage resources for PCIA ratemaking purposes, are beyond the scope of this proceeding. Both proposals require the type of policymaking the Commission prohibits in ERRA Forecast proceedings, and at minimum merit record development in a non-expedited proceeding. PG&E should make those proposals in Track Two of the PCIA OIR or other consolidated application proceedings in which a broader set of stakeholders can review the proposals and in which the Commission can ensure a consistent approach across all three IOUs. The Commission should not consider either proposal in this proceeding.

CalCCA does not object to the remainder of PG&E's proposed scoping issues, and lists those issues below for clarity:

1. Should the Commission adopt PG&E's request to approve 2026 ERRA Forecast revenue requirements for 2026 ratesetting purposes, all as initially forecast in PG&E's Application and as may be updated through the course of this proceeding , including (a) disposition of PG&E's forecast December 31, 2025 year-end balancing account balances, subject to adjustments for recorded balances through the AET process, and (b) disposition of recorded VAMOMA balances?
2. Should the Commission adopt PG&E's 2026 electric sales forecast?
3. Should the Commission adopt the GHG-related forecasts for 2026 described in the Application?
4. Were PG&E's recorded 2024 administrative and outreach expenses of $708,000 reasonable?
5. Should the Commission approve PG&E's rate proposals associated with its proposed total electric procurement related revenue requirements, including its GTSR proposal, to be effective in rates on January 1, 2026?

D. CalCCA Proposes Minor Changes to PG&E's Proposed Schedule

CalCCA is largely amenable to PG&E's proposed procedural schedule, and in particular supports moving briefing deadlines following (rather than prior to) the Fall Update. CalCCA however recommends comments on the Fall Update be due **November 5** rather than November 3 as PG&E proposes (two days later). CalCCA's attorneys and experts, who work on at least six ERRA cases, will be challenged to turn around comments on the Fall Update two business days after preparing reply briefs. A November 5 deadline will help ensure that parties have the time they need to rigorously address PG&E's Fall Update testimony. CalCCA has conferred with PG&E counsel and can represent that PG&E would not object to a November 5 deadline for Fall Update comments. CalCCA's recommended procedural schedule is below, for clarity:

EVENT	PG&E'S PROPOSED SCHEDULE	CALCCA'S PROPOSED SCHEDULE
Application filed	May 15, 2025	May 15, 2025
Notice of Application appears in Daily Calendar	May 19, 2025	May 19, 2025
Protests Filed	+ 30 days after Notice	June 18, 2025
Reply Filed	+ 10 days after Protests/ Responses	June 28, 2025
Prehearing Conference	By July 17, 2025	By July 17, 2025
Intervenor testimony served	September 2, 2025	September 2, 2025
Rebuttal testimony served	September 23, 2025	September 23, 2025
Rule 13.9 Meet and Confer	September 26, 2025	September 26, 2025
Evidentiary Hearings (if needed)	October 1-2, 2025	October 1-2, 2025
Update to Prepared Testimony (Fall Update)	October 15, 2025	October 15, 2025

EVENT	PG&E'S PROPOSED SCHEDULE	CALCCA'S PROPOSED SCHEDULE
Concurrent Opening Briefs	October 20, 2025	October 20, 2025
Concurrent Reply Briefs	October 30, 2025	October 30, 2025
Concurrent Comments to Fall Update filed; proceeding submitted	November 3, 2025	November 5, 2025
Proposed Decision	November 2025	November 2025
Comments on Proposed Decision	+4 business days after Proposed Decision	+4 business days after Proposed Decision
Reply comments	+3 business days after Comments on Proposed Decision	+3 business days after Comments on Proposed Decision

E. Other Procedural Requests in Light of the Compressed Nature of this Proceeding.

PG&E and CalCCA have worked cooperatively and constructively in recent ERRA Forecast proceedings, which has allowed both parties to litigate this expedited case without unnecessary motion practice. CalCCA expects both parties will do so again this year. Nevertheless, to promote clear expectations, CalCCA requests that the Commission:

- Set the default discovery timelines for all parties to: (1) five business days prior to the Fall Update; (2) three business days after rebuttal testimony; and (3) two business days after the Fall Update is filed, with exceptions from those timelines allowed in the event that PG&E requires more time due to the number or breadth of data requests;
- Require PG&E to serve public and confidential workpapers concurrently with all supplements and updates to testimony;
- Require from PG&E a clear presentation of modifications between its Prepared Testimony and any supplemental testimony; and
- Require PG&E to serve public and confidential workpapers contemporaneously with all testimony supplements and updates over the course of the proceeding.

IV. COMMUNICATIONS AND SERVICE

CalCCA consents to "email only" service and request that the following individuals be added to the service list for A.25-05-011 on behalf of CalCCA:

Party Representative
Nikhil Vijaykar
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (408) 621-3256
E-mail: nvijaykar@keyesfox.com

Information-Only Please include the individuals listed below on the information-only service list for this proceeding:

Brian Dickman
NEWGEN STRATEGIES & SOLUTIONS LLC
225 Union Boulevard, Suite 450
Lakewood, CO 80228
Telephone: (303) 828-4035
E-mail: bdickman@newgenstrategies.net

Tim Lindl
KEYES & FOX LLP
580 California St., 12th Floor
San Francisco, CA 94104
Telephone: (415) 516-6654
E-mail: tlindl@keyesfox.com

Leanne Bober
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9815
Email: leanne@cal-cca.org

Jack Buckley
NEWGEN STRATEGIES & SOLUTIONS LLC
225 Union Boulevard, Suite 450
Lakewood, CO 80228
Telephone: (303) 557-7700
Email: jbuckley@newgenstrategies.net

Willie Calvin
Regulatory Case Manager
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9504
Email: willie@cal-cca.org

V. CONCLUSION

For the foregoing reasons, CalCCA requests that the Commission set this matter for hearing to fully examine the issues discussed above.

June 18, 2025

Respectfully submitted,

Nikhil Vijaykar
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (408) 621-3256
E-mail: nvijaykar@keyesfox.com

Counsel for CALIFORNIA COMMUNITY CHOICE ASSOCIATION

FILED
06/20/25
04:59 PM
R2103011

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

Order Instituting Rulemaking to Implement Senate Bill 520 and Address Other Matters Related to Provider of Last Resort.	R.21-03-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROCEDURAL PATHWAY TO ADDRESS APPLICATIONS FOR PROVIDER OF LAST RESORT STATUS

Leanne Bober,
Director of Regulatory Affairs and
Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

June 20, 2025

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS

CalCCA recommends that the Commission:[1]

- Issue a Decision adopting the Ruling's definition of "POLR-specific services" only;

- Reject party arguments that support unlawfully extending Commission oversight of a non-IOU LSE POLR beyond POLR-specific services, including:

    - Rejecting arguments of Cal Advocates, PG&E, and SDG&E asserting the impossibility of separating POLR from non-POLR services based on hypothetical situations and speculation, because such arguments do not comport with Public Utilities Code sections 216 and 387[2] and are not based on substantial evidence to support a Commission Decision;
    - Rejecting arguments of Cal Advocates, PG&E, and SDG&E that all services provided by a non-IOU LSE providing POLR services must be under the Commission's broad jurisdiction because the LSE's non-POLR services can be financially impacted by the POLR-services. These arguments ignore the statutory requirements that a non-IOU LSE POLR fulfill extensive financial criteria;
    - Rejecting arguments of Cal Advocates and SDG&E to unreasonably broaden Commission oversight based on the guise of customer captivity or the need for additional customer protections given these situations are speculative and irrelevant in most cases; and
    - Rejecting SCE's definition of "Fully Severable Services" as those requiring the establishment of a non-IOU LSE POLR affiliate, given this requirement is unreasonably narrow and ignores other potentially acceptable non-IOU LSE POLR structures;

- Reject PG&E's recommendation to place requirements regarding public and governing board approvals on non-IOU LSEs and CCAs because such requirements are not only unlawful and impractical, but also unnecessary;

- Reject SCE's recommendation to supplement the Ruling's procedural pathway with a Decision on the threshold issues as party and Commission resources should be conserved until an LSE seeks to serve as the non-IOU LSE; and

- Reject SDG&E's request to address "carry-over" issues from Phase 1 as such issues are either being addressed in other venues or are moot.

---

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

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 520 and Address Other Matters Related to Provider of Last Resort.	R.21-03-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROCEDURAL PATHWAY TO ADDRESS APPLICATIONS FOR PROVIDER OF LAST RESORT STATUS

California Community Choice Association[3] (CalCCA) submits these Reply Comments to party Opening Comments on the *Administrative Law Judge's Ruling Seeking Comment on Procedural Pathway to Address Applications for Provider of Last Resort Status*[4] (Ruling)*,* dated May 28, 2025.

I. INTRODUCTION

The Ruling's proposed procedural pathway would close this proceeding through a Decision establishing a "*framework* for its regulatory authority over a non-IOU POLR and the services it provides."[5] This procedural pathway is largely supported by parties, including CalCCA, as it properly conserves party and California Public Utilities Commission

---

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 *Administrative Law Judge's Ruling Seeking Comment on Procedural Pathway to Address Applications for Provider of Last Resort Status,* Rulemaking (R.) 21-03-011 (May 28, 2025).

5 *Ibid.* (emphasis added).

(Commission) resources given no party currently seeks to serve as a non-investor-owned utility (non-IOU) load-serving entity (LSE) provider of last resort (POLR) in the near-term.

Despite this clear and efficient path forward, several parties' Opening Comments continue to suggest complicating this framework and extending broad Commission jurisdiction over *all* non-IOU operations based on purely hypothetical scenarios. As advanced by CalCCA throughout this Phase 2, however, such broad jurisdiction is inconsistent with the Commission's statutory authority set forth in Public Utilities Code sections 216 and 387 to regulate a non-IOU LSE POLR as to its *POLR services only*.

In establishing the framework, the Commission only needs to adopt the Ruling's definition of POLR-specific services – *i.e.,* "[s]ervices whose only purpose is to execute POLR responsibilities [*e.g.,* when a [LSE] fails, transferring that LSE's customers to the POLR]." This definition allows LSEs to understand which services the Commission will (and will not) exert its authority over pursuant to Public Utilities Code sections 216 and 387. LSEs can then later propose the structure of their non-IOU LSE POLR service to the Commission, which will guide how that specific jurisdictional framework is established based on the "POLR-specific services" definition.

CalCCA therefore recommends that the Commission:

- Issue a Decision adopting the Ruling's definition of "POLR-specific services," only;
- Reject party arguments that support unlawfully extending Commission oversight of a non-IOU LSE POLR beyond POLR-specific services, including:
    - Rejecting arguments of The Public Advocates Office at the California Public Utilities Commission (Cal Advocates), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) asserting the impossibility of separating POLR from non-POLR services based on hypothetical situations and speculation, because such arguments do not comport with Public Utilities Code sections 216 and 387 and are not based on substantial evidence to support a Commission Decision;

- Rejecting arguments of Cal Advocates, PG&E, and SDG&E that all services provided by a non-IOU LSE providing POLR services must be under the Commission's broad jurisdiction because the LSE's non-POLR services can be financially impacted by the POLR-services. These arguments ignore the statutory requirements that a non-IOU LSE POLR fulfill extensive financial criteria;
- Rejecting arguments of Cal Advocates and SDG&E to unreasonably broaden Commission oversight based on the guise of customer captivity or the need for additional customer protections given these situations are speculative and irrelevant in most cases; and
- Rejecting Southern California Edison Company's (SCE) definition of "Fully Severable Services" as those requiring the establishment of a non-IOU LSE POLR affiliate, given this requirement is unreasonably narrow and ignores other potentially acceptable non-IOU LSE POLR structures;

- Reject PG&E's recommendation to place requirements regarding public and governing board approvals on non-IOU LSEs and CCAs because such requirements are not only unlawful and impractical, but also unnecessary;
- Reject SCE's recommendation to supplement the Ruling's procedural pathway with a Decision on the threshold issues as party and Commission resources should be conserved until an LSE seeks to serve as the non-IOU LSE; and
- Reject SDG&E's request to address "carry-over" issues from Phase 1 as such issues are either being addressed in other venues or are moot.

II. THE COMMISSION SHOULD ADOPT THE RULING'S DEFINITION OF POLR-SPECIFIC SERVICES, AND REJECT PROPOSED DEFINITIONS THAT UNLAWFULLY AND SPECULATIVELY BROADEN COMMISSION OVERSIGHT OVER A NON-IOU LSE POLR

The Commission should issue a Decision adopting the Ruling's definition of "POLR-specific services" only, as recommended in CalCCA's Ruling Opening Comments.[6] At the same time, the Commission should reject arguments set forth in parties' Opening Comments that would have the effect of unlawfully and speculatively extending Commission oversight of a non-IOU LSE POLR beyond its POLR-specific services. As previously stated by CalCCA in

[6] *See* CalCCA Opening Comments, at 4-8 ("in defining the Commission's authority over a non-IOU LSE POLR, the Commission need only adopt its definition of "POLR-specific services" because: (1) the plain language of Public Utilities Code sections 216 and 387 explicitly and unambiguously limit the Commission's statutory authority over a non-IOU LSE to "POLR-specific services"; (2) the legislatively protected autonomy of CCAs must be preserved; and (3) "POLR-specific services" can be isolated and defined separately from all other CCA services. Defining "Fully-severable services" or "Non-severable services" is unnecessary and in all events these services will fall outside the Commission's jurisdiction.").

comment throughout Phase 2, any argument that a non-IOU POLR cannot offer separate POLR and non-POLR services has no statutory basis, as the plain language of sections 216 and 387 clearly limit the Commission's jurisdiction over a non-IOU LSE POLR to "POLR-specific services."[7] From a practical perspective, CalCCA has already provided several examples of potentially feasible non-IOU LSE POLR structures that could allow for that separation under California law.[8]

As set forth below, the Commission should therefore reject the following party arguments that POLR-specific services can never be severed, or that any particular non-IOU POLR LSE structure must be established. <u>First</u>, the Commission should reject the arguments of Cal Advocates, PG&E, and SDG&E regarding the impossibility of separating POLR from non-POLR services, as the scenarios presented are hypothetical and speculative, do not comport with sections 216 and 387, and seek a Commission Decision that is not based on substantial evidence. <u>Second</u>, the Commission should reject Cal Advocates', PG&E's, and SDG&E's recommendations that the Commission exert broad authority over *all* services provided by a non-IOU LSE providing POLR service because the non-IOU LSE's non-POLR-related services could be negatively financially

---

[7] *See California Community Choice Association's Comments on Threshold Questions,* R.21-03-011 (Jan. 10, 1025), at 6-9 (CalCCA Comments on Threshold Questions); *California Community Choice Association's Reply Comments on Threshold Questions,* R.21-03-011 (Jan. 24, 2025) (CalCCA Reply on Threshold Questions), at 6-16; CalCCA Opening Comments, at 4-6 (citing section 387(j) that "the commission shall supervise and regulate each [POLR], as necessary, as a public utility *for the services provided by the [POLR]"* and section 216(a)(2) that a POLR "is a public utility subject to the jurisdiction, control, and regulation of the commission . . . *regarding providing that service."*).

[8] *See* CalCCA Reply on Threshold Questions, at 15-16 (providing examples of non-IOU LSE POLR structures, including: (1) designated POLR operating each service with separate procurement portfolios, with separate POLR and non-POLR-rates, allowing the Commission to regulate only the POLR rates to ensure they are just and reasonable; (2) designated POLR operates with one procurement portfolio, electing to charge any incremental costs associated with procurement to serve involuntarily returned load to those customers, with the Commission having the ability to regulate the POLR rates; or (3) designated POLR establishes separate, POLR-specific entity providing POLR services entirely separate from the affiliated entity's non-POLR offerings, again allowing the Commission regulatory oversight over the POLR rates).

impacted by the POLR-services. This argument ignores the separate statutory requirement for the non-IOU LSE POLR to fulfill Commission-directed financial requirements to serve as the POLR. Third, the Commission should reject SDG&E's and Cal Advocates' arguments to unreasonably broaden Commission oversight based on the guise of customer captivity or the need for additional customer protections, as these arguments are based on speculation and are irrelevant in most cases. Fourth, SCE's definition of "Fully Severable Services" as those requiring the establishment of a non-IOU LSE POLR affiliate to provide the POLR services should be rejected as it is unreasonably narrow and ignores potentially acceptable non-IOU LSE POLR structures.

A. Any Commission Assertion of Jurisdiction Must be Based on Statutory Authority and Substantial Evidence, Rather than the Hypotheticals and Speculation Advanced by Cal Advocates, PG&E and SDG&E

PG&E, SDG&E, and Cal Advocates argue that the Commission should revise its definitions over POLR and non-POLR services to reflect that the Commission's jurisdiction over the non-IOU POLR *likely* must extend beyond its "POLR-specific services." Notably, these parties are not able to conclusively argue that the Commission must exert jurisdiction over the entire non-IOU POLR operation, because no structure for a non-IOU POLR has been proposed. Instead, their arguments are based on conjecture that the non-IOU POLR would *never* be able to sever POLR-services.[9]

---

[9] *See* PG&E Opening Comments, at 2-3 ("PG&E continues to believe . . . that it ***would be likely be infeasible*** for a non-IOU POLR to sever any services required to meet the statutory POLR obligation. . . PG&E ***questions*** whether there can truly be any "fully-severable service . . . PG&E ***does not see*** how any services could ***possibly*** be sufficiently separated . . . .") (emphasis added); SDG&E Opening Comments, at 8-10 (in arguing that "the Commission must regulate all other retail electric generation services offered by the [non-IOU LSE] POLR," speculating that the POLR ***will always*** be the only provider available for non-transitional service, and stating that "[f]or existing customers, as well as customers who transfer to the non-IOU POLR from another LSE, the electric generation service provided by the non-IOU POLR (whether it is transitional or standard service) ***is*** the POLR service since the POLR is the ***only*** provider obligated or even available ***in most cases*** to provide electric generation service to its captive customers.") (emphasis added); Cal Advocates Opening Comments, at 2-3 ("Activities that affect a non-IOU LSE's revenue requirement, customer rates, financial stability, and the reliable delivery of electrical services ***can***

The Commission should not close the door on a non-IOU LSE proposing a structure for its POLR services in which it can adequately separate its POLR and non-POLR functions, either through accounting or organizational mechanisms, simply based on hypothetical situations, speculation, and conjecture. Such a directive would not only violate sections 216 and 387, but would also violate the Commission's duty to base its decisions on substantial evidence considering the record.

First, and as stated above, sections 216 and 387 expressly and unambiguously provide that the Commission's authority to regulate a non-IOU LSE POLR extends only to its provision of POLR services. Section 387(j) provides that "the commission shall supervise and regulate each [POLR], as necessary, as a public utility *for the services provided by the [POLR]."* Section 216(a)(2) states that a POLR "is a public utility subject to the jurisdiction, control, and regulation of the commission . . . *regarding providing that service."* The Commission's statutory authority is therefore clear as to its regulation over POLR services only.

In addition, the Commission must base its decisions on substantial evidence in light of the whole record, as required by Public Utilities Code section 1757(a)(4). Speculation, conjecture, or assumptions unsupported by evidence cannot satisfy this standard and may not lawfully serve as the basis for a Commission determination.[10] Any findings therefore must be

---

directly impact the non-IOU POLR's ability to meet its POLR obligations. . . ***For instance,*** a core POLR responsibility such as onboarding thousands of new customers from a failed LSE and rapidly procuring power to serve them, ***can*** spike procurement and administration costs, especially if the financial security requirement (FSR) is inadequate. ***Under such a scenario,*** the LSE serving as the POLR ***may*** face unanticipated financial strain from fulfilling its POLR obligations, which ***could****,* in turn, deplete reserves, [etc.]. . . .") (emphasis added).

[10] *See Ponderosa Tel. Co. v. Pub. Util. Comm'n* (2019) 36 Cal.App.5th 999, 1013 (discussing standard of review of Commission decisions); *see also* D.11-06-003, *Application of Pacific Gas and Electric Company for Approval of 2008 Long-Term Request for Offer Results and for Adoption of Cost Recovery and Ratemaking Mechanisms* (U 39 E), A.09-09-021 (June 3, 2011) at 24, n. 27 ("Like the courts, the Commission must look to the direct evidence, but also can draw reasonable inferences derived from the evidence, so long as these inferences are reasonable and not based on "'speculation, conjecture, imagination or guesswork" (citations omitted)).

supported by concrete, credible evidence in the record—not mere assertion or hypothetical projections.

CalCCA recognizes that certain non-IOU LSE POLR structures could indeed necessitate broad Commission regulation if the POLR-specific services are inextricably intertwined with CCA operations. However, as CalCCA has previously identified, there are many ways to ensure the POLR-specific services can be identified and separately regulated.[11] Foreclosing the opportunity for non-IOU LSEs desiring to take on POLR responsibilities from demonstrating that separation based on speculation of parties *doubting* it is possible does not rise to the substantial evidence necessary for a Commission decision. Accordingly, the Commission should reject party arguments stating that the Commission should exert broad authority over a non-IOU LSE serving as POLR. Instead, the Commission should adopt the definition of "POLR-specific services" set forth in the Ruling.

B. Any Argument that Severability of POLR-Specific Services Depends on Whether the Financial Health of the Non-IOU POLR is Impacted Should be Rejected as it Ignores the Existing Statutory Financial Requirements for the Non-IOU POLR

Cal Advocates, PG&E, and SDG&E argue that the severability of POLR-specific services depends on whether the POLR services could impact the LSE's financial health, including capital reserves, credit rating, revenues, or overall financial health. These parties argue that since POLR service will inevitably impact the finances of a non-IOU LSE, the Commission must regulate the non-IOU LSE POLR broadly.

For example, Cal Advocates argues that the only services not under Commission jurisdiction should be those "[s]ervices that do not affect the provision of POLR services nor the

[11] *See supra,* n. 8.

overall health of the LSE serving as the POLR."[12] In addition, PG&E questions how any POLR services can be sufficiently separated given the "ability to meet the core POLR function – to take on the customers of a failed LSE with little-to-no-notice – . . . requires adequate financial capacity."[13] PG&E argues that the Commission must therefore oversee all activities impacting a non-IOU LSE POLR's financial condition, as it does with the IOUs. Finally, SDG&E argues that even "fully-severable" services must be subject to the Commission's jurisdiction, "to ensure the financial integrity of the non-IOU POLR, to prevent unlawful cross-subsidization between the non-IOU POLR's regulated electric generation service and its unregulated venture, and to protect the non-IOU POLR's captive customers."[14]

The Commission's authority to ensure the financial ability of a non-IOU LSE to serve as POLR should not result in the extension of its jurisdiction over all non-IOU LSEs' operations and finances. As noted above, the Commission's statutory authority is limited to the LSE's ability to provide POLR-specific services. In addition, section 387 already provides the Commission with the authority to develop threshold attributes for a non-IOU LSE POLR that must include "minimum financial requirements necessary to provide electricity to retail end-use customers in each service territory" for an LSE "to serve as POLR."[15] Section 387 also requires a non-IOU POLR LSE applicant to include in its application "[a] demonstrated ability . . . to post a bond sufficient to meet" these minimum financial requirements.[16] CalCCA does not deny that the Commission has statutory authority over these minimum financial requirements. Indeed,

---

12 Cal Advocates Opening Comments, at 4.
13 PG&E Opening Comments, at 3.
14 SDG&E Opening Comments, at 9.
15 Pub. Utils. Code § 387(f)(2).
16 *Id.* § 387(c)(1).

CalCCA provided its proposal regarding such minimum financial requirements in its Comments on the Threshold Questions.[17]

By statute, the Commission therefore already has jurisdiction to ensure the non-IOU LSE POLR has the financial wherewithal to serve returning customers. Further expanding the Commission's jurisdiction regarding a CCA's "non-POLR services" or "non-severable POLR services" to ensure Commission oversight into a non-IOU LSE's overall financial condition is therefore unnecessary and should be rejected.

C. The Commission Should Reject Cal Advocates' and SDG&E's Arguments to Unreasonably Broaden Commission Oversight Based on the Guise of Customer Captivity or the Need for Additional Customer Protections

The Commission should reject SDG&E's and Cal Advocates' arguments that broad Commission oversight over a non-IOU LSE POLR is necessary because if a customer is involuntarily returned to the non-IOU LSE POLR, it will become "captive" and have no alternative provider. CalCCA already extensively rebutted this argument in its Reply to the Threshold Questions.[18] While SDG&E and Cal Advocates insist the Commission must assert broad authority given the non-IOU's "existing retail service" becomes the only service available, they provide no reason as to how this will *always* be the case. There are many ways that a customer involuntarily being returned to a non-IOU LSE POLR could play out, many of which do not involve a lack of alternative providers. By serving as the POLR, the non-IOU LSE does not automatically become the sole or default provider in that service territory.

In addition, even if a customer becomes "captive," to a CCA, which is unlikely, CCAs are public agencies already held accountable to the public. CCAs have no profit motive, have existing obligations to set rates in public, conduct their meetings in public, and allow for public

---

17 *See* CalCCA Comments on Threshold Questions, at 15-16.
18 *See* CalCCA Reply on Threshold Questions, at 12-14.

participation. That public agency accountability is analogous to – and displaces the need for – the Commission's review of CCA rates and services. Therefore, SDG&E's and Cal Advocates' arguments that broad Commission authority is necessary for a non-IOU LSE POLR given a "captive" customer situation should be rejected.

D. While SCE Correctly Acknowledges that a Non-IOU POLR Can Separate POLR and Non-POLR Services, its Proposed Definition of "Fully Severable Services" Requiring the Establishment of an Affiliate is Unreasonably Narrow

The Commission should reject SCE's claims that the only workable structures for Commission authority over a non-IOU LSE POLR are either full Commission regulation over all services provided by a non-IOU LSE POLR, or the establishment of a POLR affiliate. SCE claims that limiting Commission authority to just POLR service can only be accomplished by severing part of a non-IOU LSE's procurement operation to dedicate it to POLR service through an affiliate.[19] While an affiliate may be one of the pathways a non-IOU LSE can take to establish non-IOU POLR service, SCE fails to justify this narrow definition which forecloses the variety of pathways the non-IOU LSE could potentially take. In addition, while SCE claims that Affiliate Transaction Rules for Non-IOU LSE POLRs would need to be crafted, such rules need only be addressed if a non-IOU LSE submits a Petition for Rulemaking (PFR) to become a Designated POLR through an affiliate entity. This aligns more closely with the proposed path forward in this proceeding – that is, to preserve party resources until interest arises.

III. PG&E'S RECOMMENDATION FOR ADDITIONAL REQUIREMENTS FOR PUBLIC AND GOVERNING BOARD APPROVALS IS UNNECESSARY

PG&E's recommendations to require non-IOU entities to provide additional showings demonstrating approval by customers and governing boards of the non-IOU LSE POLR are unnecessary and should be rejected. PG&E's proposals require: (1) a non-IOU entity seeking to

[19] SCE Opening Comments, at 2-5.

assume a POLR role to show, through a verification, that "various" governing boards in the area to be served have expressed their approval by formal vote to demonstrate interest by customers in that area; and (2) for CCAs specifically, an additional requirement to demonstrate that its governing board and the necessary authorities of the cities/counties that are part of the CCA have approved its plan to assume POLR duties.

From a statutory jurisdictional standpoint, the Commission does not have the authority to require CCAs to provide these showings. From a practical standpoint, obtaining a "formal vote" from the communities making up a CCA interferes with the decision-making process unique to each CCA, and could be unduly burdensome given some CCAs are comprised of over 30 cities and counties. In addition, given the significance of a decision by a CCA to apply for non-IOU LSE POLR status, and of the actual POLR plan to be submitted to the Commission, CCAs would regularly seek their governing board approval prior to such submissions. Therefore, such a requirement is not only unlawful and impractical, but is also unnecessary because a CCA would be required to receive the requisite approvals in any case.

IV. SCE'S RECOMMENDATION TO SUPPLEMENT THE RULING'S PROCEDURAL PATHWAY WITH A DECISION ON THE THRESHOLD ISSUES SHOULD BE REJECTED

CalCCA supports the Ruling's proposed procedural pathway, which would result in a Commission Decision that provides a framework for the Commission's regulatory authority over a non-IOU POLR and the service it provides. As no party has expressed near term interest in assuming a non-IOU POLR role, this level of initial guidance is appropriate. SCE, however, recommends that the Commission additionally resolve the statutory threshold attributes now, obviating the need for further rulemaking and allowing potential designated-POLRs to move forward with a joint application.[20] SCE claims that addressing the statutory threshold attributes now would be "more efficient" and can be "based on the existing record." SCE is the only party suggesting this path forward.

The Commission should reject SCE's recommendation. There is no pressing need to resolve the threshold statutory issues SCE raises, as no party has expressed a desire to serve as the non-IOU LSE POLR in the near-term. As noted in the Ruling, it is prudent to conserve limited party and Commission resources considering these circumstances. Upon receipt of a PFR, the Commission can resume consideration of the topics SCE raises and would have the benefit of additional insight at the point a non-IOU entity seeks authority to assume POLR responsibilities. Accordingly, CalCCA recommends the Commission adopt the procedural pathway set forth in the Ruling and reject SCE's request.

V. SDG&E'S REQUEST TO ADDRESS PHASE 1 CARRY-OVER ISSUES SHOULD BE REJECTED

The Commission should reject SDG&E's request to address Phase 1 carry-over issues, given those issues are either being addressed in other venues, or are moot. First, incorporating seasonal RA pricing into the FSR methodology adopted in D.24-04-009[21] is unnecessary at this time, given the RA market price benchmark is currently being revised in the Power Charge Indifference Adjustment Rulemaking which will impact the ability to compute such seasonal pricing.

Second, regarding SDG&E's request that the Commission address the process and timing of an IOU POLR being notified of a CCA financial trigger event, the Commission recently issued a Draft Resolution addressing how an IOU POLR would receive notice in the event of a

---

[20] SCE Opening Comments, at 5-6.

[21] D.24-04-009, *Decision Implementing Senate Bill 520 Regarding Standards for Provider of Last Resort*, R.21-03-011 (Apr. 18, 2024).

CCA trigger event.[22] The Draft Resolution allows a CCA to secure confidential treatment through regular Commission processes, but also states that:

> [I]t may be necessary for ED to make the POLR aware of the fact of a potential return of customers to the POLR if the threat of a mass involuntary (and unplanned) return to POLR appears credible. ED Staff may use its discretion to determine whether a potential return appears significant and necessitates informing the POLR.

Given the Commission is handling the notice issue through the Draft Resolution, the Commission need not address this issue in Phase 2.

Third, SDG&E requests that the Commission address the "[p]rocedures and mechanisms to address liquidity needs of the IOU POLR." This request, previously raised by PG&E, should be denied. The Commission already considered and denied PG&E's request to establish a minimum FSR amount based on two months of energy procurement to address potential POLR liquidity issues, finding that: (1) this amount will overstate the amount of costs relative to revenues; (2) PG&E failed to sufficiently demonstrate it lacks sufficient liquidity or access to financing to enable it to serve returning load; and (3) the Commission authorized the POLR to establish a memorandum account to adequately track procurement and financing costs.[23] As a result of this issue already being addressed, there is no need for the Commission to reconsider it in Phase 2.

VI. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests that the Commission: (1) adopt the Ruling's definition of "POLR-specific services," only; (2) reject all party arguments seeking to expand Commission authority over non-IOU LSE POLRs; (3) reject PG&E's recommendation to place additional approval requirements on non-IOU LSE POLRs; (4) reject SCE's recommendation

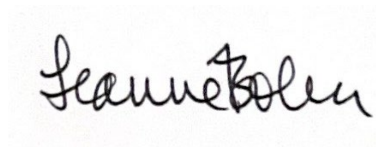
---

[22] *See* Draft Energy Division Resolution E-5406, at 9-10.

[23] D.24-04-009, at 46-47, and Conclusion of Law 26, at 107.

that the Commission incorporate into its Decision the statutory threshold attribute requirements; and (5) reject SDG&E's request to address Phase 1 carry-over issues in the Phase 2 Decision.

Respectfully submitted,



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

June 20, 2025

Docket No.: A.24-11-007

Exhibit No.: CalCCA-01

Date: June 30, 2025

Witness: Lori Mitchell, San Jose Clean Energy
Kris Van Vactor, Silicon Valley Clean Energy

AMENDED TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY FOR APPROVAL OF ELECTRIC RULE 30 FOR TRANSMISSION-LEVEL RETAIL ELECTRIC SERVICE
A.24-11-007

TABLE OF CONTENTS

APPENDIX

ATTACHMENTS

I. INTRODUCTION AND SUMMARY

The California Community Choice Association (CalCCA) [1] presents this testimony in the *Application of Pacific Gas and Electric Company for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service*.[2] Sections I, II, and IV of this testimony were prepared by or at the direction of Lori Mitchell, Director of San Jose Clean Energy (SJCE). Ms. Mitchell's qualifications are set forth in Attachment A. Section III was prepared by or at the direction of Kris Van Vactor, Director of Power Resources, Silicon Valley Clean Energy (SVCE). Mr. Van Vactor's qualifications are set forth in Attachment B.

In its Application, Pacific Gas and Electric Company (PG&E) proposes a new Rule 30 Tariff to address interconnection of new customers requesting retail electric service at transmission level voltages between 50 kilovolts (kV) and 230 kV (Large Loads).[3] The Scoping Ruling in this proceeding includes as Issue 4.b: "What information-sharing requirements should PG&E adopt to ensure that the [Community

---

[1] CalCCA represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy (Ava), Central Coast Community Energy (3CE), Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy (MCE), Orange County Power Authority, Peninsula Clean Energy (PCE), Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority (RCEA), San Diego Community Power, San Jacinto Power, San José Clean Energy (SJCE), Santa Barbara Clean Energy, Silicon Valley Clean Energy (SVCE), Sonoma Clean Power, and Valley Clean Energy. A subset of CalCCA members (Ava, 3CE, MCE, PCE, RCEA, SJCE and SVCE, collectively the Joint CCAs) addressed Pacific Gas and Electric Company's (PG&E) application by, among other things, filing a response, dated December 23, 2024, and filing a reply to PG&E's request for interim implementation, dated April 11, 2025. On June 18, 2025, the Assigned Administrative Law Judge (ALJ) to this proceeding approved the Motion for Party Status for CalCCA, which will represent all of its members in this proceeding, including the Joint CCAs.

[2] *Application of Pacific Gas and Electric Company (U 39 E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service*, Application (A.) 24-11-007 (Nov. 21, 2024) (Application).

[3] Application, at 1.

Choice Aggregators (CCAs)] affected by Rule 30-related load growth can meet projected demand in their service areas?"[4] Issue 4.b. is included because while PG&E provides delivery service, CCAs are the default generation service providers in their service areas. Therefore, in areas served by CCAs, PG&E will receive information when a customer seeks to interconnect at the transmission level through a Rule 30 application. However, as discussed further, CCAs do not currently receive information regarding a Large Load customer seeking interconnection to PG&E's system.

CalCCA generally supports PG&E's efforts to attract new load by streamlining and expediting interconnection of new customers to PG&E delivery system. Greater clarity and coordination regarding new loads among all interests – PG&E, CCAs, and new customers – will serve this goal. As acknowledged by Scoping Ruling Issue 4.b., the coordination should extend to information-sharing between PG&E and the affected CCAs during the interconnection process to enable timely procurement of generation supply to the new load.

This testimony addresses CCAs' role serving California customers (Section II) and CCAs' need for information regarding new load (Section III). It includes a proposal for information-sharing from PG&E to the affected CCAs to ensure a customer's chosen generation supplier has sufficient notice to procure the supply cost-effectively and equitably (Section IV). This testimony also identifies changes needed to PG&E's proposed Rule 30 Tariff to effectuate the proposed information-sharing requirements (Section IV).

---

[4] *Assigned Commissioner's Scoping Memo and Ruling*, A.24-11-007 (Mar. 11, 2025) (Scoping Ruling), at 8.

PG&E states that it "has received 40 active applications for transmission level service with demand of 4 MW or greater [and the] total combined current requested load of the 40 applications is 8,422 MW" in 2023-2024.[5] PG&E represents that as of April, 2025, none of these applications have been withdrawn, and all are in the study/planning or design phases.[6] In 2025, PG&E states that it has received four additional applications for transmission level service.[7]

PG&E is "seeing the growth of Data Centers in [its] service territory and expect[s] this growth to continue with the large amounts of electrical demand needed to power such facilities."[8] As represented by PG&E, many of the data centers seeking interconnection in PG&E's service territory are located in areas served by CCAs.[9] Despite the role of CCAs as default providers for generation service in PG&E's service territory, CCAs often receive limited, if any, advance notice of new customer load, including large load retail customers interconnecting at the transmission-level (referred to herein as Large Load).[10] Load expansion is included in the California Energy

---

[5] PG&E Supplemental Testimony, A.24-11-007 (Mar. 21, 2025) (replacing PG&E's originally filed Testimony, submitted Nov. 21, 2024) (PG&E Testimony), at 4, lines 4-7; *see also Pacific Gas and Electric Company's (U 39 E) Response to Administrative Law Judge's Ruling Requesting Information on the Motion for Interim Implementation of Electric Rule No. 30 [Public Version],* A.24-11-007 (Apr. 4, 2025) (PG&E Response to Interim Implementation Ruling), at 8.

[6] PG&E Response to Interim Implementation Ruling, at 3, 8.

[7] *Id.* at 9.

[8] PG&E Testimony, at 5, lines 10-12.

[9] *See Pacific Gas and Electric Company's (U 39 E) Response to the California Public Advocates Office's Motion to Amend the General Rate Case Phase II Scoping Memo to Include Issues from Application 24-11-007,* A.24-09-014, at 11 ("in California, retail choice means that PG&E may not be the Load Serving Entity that provides generation service to new very large load customers, even where PG&E is the utility providing delivery services from its transmission or distribution lines. *A significant number of the very large load applications received thus far are for projects within areas served by [CCAs],* and it is uncertain which customers may choose CCA service and which customers CCAs will elect to serve.") (emphasis added).

[10] CalCCA notes that large load customers may also interconnect at the distribution system level, resulting in similar information sharing needs for CCAs with respect to those customers. CalCCA

Commission's (CEC) Integrated Energy Policy Report (IEPR) forecast communicated to CCAs by PG&E. However, CCAs receive only an aggregate number, which does not identify customers, their location, or timing of interconnection. The information provided is insufficient for procurement planning. In addition, often the IEPR forecast for Large Load differs significantly from the CCAs' own forecasts. Attempts to reconcile the load information, which ultimately impacts each CCA's Resource Adequacy (RA) and/or Integrated Resource Plan (IRP) requirements, have not been successful because CCAs have no access to underlying customer information regarding forecasted Large Load. Consequently, this lack of information prevents CCAs from proactively and cost-effectively procuring preferred energy products for Large Load customers.

Large Load customers interconnecting at the transmission-level often have a choice of where to locate a new facility. If California seeks to attract and retain these customers—and benefit from the downward pressure on delivery rates their participation can provide—the state must adopt policies that enhance the optionality and support available to Large Load customers. Key among these policies is ensuring coordination between PG&E and CCAs, as the default generation service providers in their service areas. This coordination will allow both the CCAs and PG&E to cost-effectively and equitably serve new customers.

Consistent with California policy goals, this testimony recommends that the Commission adopt information-sharing requirements obligating PG&E, as the delivery service provider, to provide customer-specific information on new Large Loads to affected CCAs within a reasonable timeframe. As an overarching principle for this

---

acknowledges that this proceeding only relates to retail customers interconnecting at the transmission-level.

proceeding, ***when PG&E has the information, the default provider CCA should have the information, consistent with confidentiality requirements, to enable the CCA to work with customer and maximize the potential for efficient procurement; there is no justification for delay.***

This testimony recommends that the Commission adopt the following load information-sharing requirements:

- For loads for which no application for interconnection service under Rule 30 (Interconnection Application) has been submitted to PG&E, but a load inquiry has been made to PG&E and the utility is incorporating the forecast into internal or external forecasts, PG&E should report to CCAs on a quarterly basis the approximate location, size, and anticipated timeline for integrating the new load. Information should be provided on a per-project basis with a unique identifier that protects the customer's identity if the customer does not wish to have their information shared with the CCA.

- When an Interconnection Application has been submitted, PG&E should provide each affected CCA a copy of the Interconnection Application within 20 calendar days of submission to PG&E, with all information relevant to potential CCA service including, as further described below in Section III.B., customer name, location, facility type (*e.g.,* data center, commercial, retail, manufacturing), capacity ramp schedule, on-site generation, and requested and current expected timing for the interconnection (Key Large Load Information).[11] PG&E should also provide all already submitted Applications for Interconnection, and any additional Key Large Load Information, to an affected CCA within 20 calendar days of a Commission directive to do so.

- PG&E should provide each affected CCA with quarterly reports that provide updates on the proposed interconnection timelines related to Interconnection Applications, and any changes to Key Large Load Information.

---

[11] PG&E refers to the Interconnection Application as the "Application Phase," namely, the milestone at which the customer first "submits a service energization request and study deposit." *See* PG&E Answer 001 to Data Request Joint CCAs_003-Q001, Question 01 (Apr. 10, 2025) attached hereto in Attachment C. The Interconnection Application process is also described in PG&E's proposed Rule 30 Tariff.

Appendix A to this testimony includes proposed changes to PG&E's proposed Rule 30 Tariff to effectuate the proposed information-sharing framework.[12]

The structure of this testimony is as follows:

- Section II addresses: (1) the role of CCAs as default providers of generation service in their service areas; (2) current CCA service to data center customers; and (3) a recommendation that the Commission adopt information-sharing requirements to provide Key Large Load Information promptly to an affected CCA.
- Section III addresses the importance of providing Key Large Load Information as early as possible, including before an Interconnection Application is submitted, to support affordable rates for California electric customers, and concludes with a recommendation that the Commission adopt information-sharing requirements that require information sharing at the time PG&E learns of new load.
- Section IV outlines the proposed information-sharing framework and associated Rule 30 Tariff revisions, included in a redline to PG&E's proposed Rule 30 Tariff, attached as Appendix A.

II. CCAS SERVE AS THE DEFAULT PROVIDERS FOR GENERATION SERVICE FOR ALL CUSTOMERS IN THEIR SERVICE AREAS INCLUDING LARGE LOAD CUSTOMERS

CCAs serve as the default providers of generation service for all customers (residential and non-residential) in their service areas, subject to each customer's ability to opt out of CCA service. CCA customers continue to receive delivery service from the investor-owned utility (IOU) serving that location. Consistent with the role as default provider, CCAs currently provide 46 percent of electric generation service in PG&E's service territory.[13]

---

[12] On June 19, 2025, the Assigned ALJ granted CalCCA's request to submit surrebuttal testimony on September 8, 2025, to provide an opportunity to respond to any proposal for information-sharing submitted by PG&E in its rebuttal testimony.

[13] *See, e.g.*, *California Energy Demand 2023 Baseline LSE and BAA Tables*, Form 1.1c (energy demand for 2023): https://efiling.energy.ca.gov/GetDocument.aspx?tn=255153; *see also* Decision (D.) 24-12-038, at 38 ("PG&E expects CCA and [Direct Access] providers to serve nearly two-thirds of total system sales in 2025.").

New generation load in a CCA territory is automatically enrolled with, or defaulted to, the CCA serving that area.[14] PG&E's Electric Rule 23.K.2 directs that "[c]ustomers establishing electric service within a CCA service area shall be automatically enrolled in CCA Service <u>at the time their electric service becomes active</u> unless the customer submits a request to the CCA to opt-out and the CCA provides notification to PG&E of any such opt out request."[15] Rule 23.K.2 further directs that PG&E "promptly notify" the CCA of the new customer.[16]

A customer can opt out of CCA service in favor of IOU bundled service. However, as outlined in Public Utilities Code section 366.2(c)(2) and stated in PG&E's Electric Rule 23.G., if a customer is in a CCA service area and does not opt out of CCA service, the CCA will serve the customer.[17] As a result, the choice of being served by a CCA solely belongs to the customer. Any new customer located in a CCA service area interconnected under the new Rule 30 Tariff will be served by the CCA serving the location where the new facility is located, unless that customer chooses to opt out of CCA service.

Consistent with the role embraced by CCAs as the default providers of generation service, CCAs already serve Large Load customers interconnected at the transmission level. While Large Load customers primarily take generation service on existing tariffs,

---

[14] Pub. Util. Code § 366.2(c)(2).
[15] PG&E Electric Rule 23.K., Sheet 32 (emphasis added).
[16] *Ibid*.
[17] PG&E Electric Rule 23.G., Sheet 25 ("Pursuant to D.05-12-041, all customers, including active Direct Access customers, located within a CCA's service area that have been offered service by the CCA that do not affirmatively decline such service (opt-out), shall be served by the CCA.").

CCAs have also worked directly with customers to design special agreements.[18] For example, SJCE currently serves five data centers and SVCE serves eight data centers.

Cost-effective and equitable generation service of Large Loads and all other customers requires early and clear insight into the Large Load's requirements. In its Application, PG&E forecasts significant load growth in its territory. CCAs will likely provide generation service to many, if not most, of these customers.[19] However, no current standards exist for when PG&E will share Key Large Load Information with CCAs. PG&E itself admits that it has not provided notice of the Interconnection Applications for load to the CCAs in its territory.[20] More surprisingly, even in impacted areas, such as the "cluster process for new transmission level retail electric customers located in Alameda and Santa Clara Counties," PG&E did not provide affected CCAs with notice.[21]

---

18 For example, SVCE entered into a special agreement with Google to provide 24/7 carbon-free energy service for Google's offices in Mountain 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. The Google/SVCE agreement provides a scalable model for others to follow, and demonstrates the power of community collaboration in accelerating the transition to a clean energy future. *See* "Silicon Valley Clean Energy and Google Announce Comprehensive 24/7 Carbon-Free Energy Agreement" (June 15, 2022), located at *https://svcleanenergy.org/news/silicon-valley-clean-energy-and-google-announce-comprehensive-24-7-carbon-free-energy-agreement/*

19 *See* PG&E Testimony, at 4, lines 4-7; *see also* note 9, *supra* (PG&E acknowledging that a "significant number" of Large Load applications received thus far are in CCA service areas).

20 *See* PG&E Answer to Data Request Joint CCAs_001-Q001, Question 01-a. (Jan. 29, 2025) (attached hereto in Attachment C) ("These applications do not concern the provision or procurement of electric commodity service. Thus, PG&E did not provide notice to energy providers such as Community Choice Aggregators (CCAs)….").

21 *See* PG&E Answer to Data Request Joint CCAs_001-Q002, Question 02-a. (Jan. 29, 2025) (attached hereto in Attachment C) ("Given that the Pilot Cluster Process involved the interconnection of new electric customers, not the procurement of the electric commodity, PG&E did not provide notice directly to Community Choice Aggregators (CCAs).").

The Commission should adopt requirements for information sharing that ensure both the CCA, for unbundled customers, and the IOU, for bundled customers, can secure the most affordable rates for their customers. Absent such requirements, it is evident from PG&E's past conduct (discussed further in Section III below) that PG&E will not share Large Load information with CCAs. There should be no difference in the amount of time PG&E, as the delivery service provider, has customer-specific information, and the amount of time CCAs have the same customer-specific information. Any information shared will be protected consistent with current oversight by the Commission of CCAs and in accordance with currently effective Non-Disclosure Agreements (NDAs) between the CCAs and PG&E.

CCAs are the default providers of generation service for new transmission-level service customers in the CCA's respective service area. Given this primary role serving generation service, CCAs should receive information on new loads promptly, and consistent with the framework described in Section IV of this testimony.

III. CCAS AS DEFAULT PROVIDERS OF GENERATION SERVICES NEED EARLY ACCESS TO LARGE LOAD CUSTOMER INFORMATION

As noted above, cost-effective procurement decisions are driven by access to customer information. As demonstrated by the load applications PG&E has received and not shared with the CCAs, including PG&E Advice Letter (AL) 7604-E[22] (discussed below), the CCAs are getting notice of new customers materially after PG&E is aware of the load. These delays frustrate the ability of CCAs to make cost-effective procurement decisions

[22] PG&E Advice Letter (AL) 7604-E, *Electric Rules 2, 15, and 16 Exceptional Case Submittal for Electric Transmission Interconnection for Sunnyvale Technology Partners LLC c/o Menlo Equities* (May 27, 2025), at 2.

consistent with compliance requirements. Given the role of CCAs as default providers of generation service, CCAs should have load information at the same time as PG&E.

A. PG&E Has Not Timely Shared New Large Load Information

PG&E has not timely shared information regarding Interconnection Applications for Large Loads. For example, on May 27, 2025, PG&E submitted AL 7604-E for approval of an agreement between PG&E and Menlo Equities for a new 49 MW data center in Sunnyvale, California. SVCE is the default generation provider for the proposed location of the data center. According to AL 7604-E, Menlo Equities submitted its application for service on April 11, 2024.[23] Therefore, at that time PG&E obtained information on the facility's "peak demand," "system load and generation forecasts" and "future energy resource needs."[24] At no point, however, did PG&E provide SVCE with any notice of the prospective customer. SVCE only learned of the potential new load when AL 7604-E was publicly submitted, 13 months after the application for service was submitted to PG&E by the customer.

A similar advice letter for a data center in SJCE's territory was submitted on April 18, 2025.[25] In that instance, PG&E acknowledged that it did not share any information with the affected CCA in advance of the advice letter submittal.[26]

---

[24] *See* PG&E Response to Interim Implementation Ruling), at 20-21 (describing PG&E's use of customer information for determining Resource Adequacy and future energy needs, and PG&E's provision of customer information to the California Independent System Operator and California Energy Commission).

[25] *See* PG&E Advice Letter 7569-E, *Electric Rule 2, 15, and 16 Exceptional Case Submittal for Electric Transmission Service Facilities for STACK* (Apr. 18, 2025).

[26] *See Pacific Gas and Electric Company's Reply to the Response to Joint CCAs to Advice 7569-E-Electric Rule 2, 15 and 16 Exceptional Case Submittal for Electric Transmission Service Facilities for STACK* (May 15, 2025), at 2.

PG&E stated in April, 2024 that it "anticipates there will be up to nine (9) applications ready to submit to the Commission for review and approval by the end of June 30, 2025," with additional filings "in the remainder of 2025 and 2026."[27] Only two filings have been made as of the date of this Testimony (Stack and Menlo Equities), leaving many still to be filed. To the extent that any of these facilities are in SVCE's service area, SVCE has received no notice of the new load from PG&E.

B. Access to Timely, Customer-Specific Data Enables Proactive Procurement Strategies

Cost-effective procurement requires the CCA to consider the needs of each individual customer as well as the broader compliance requirements for the CCA, including RA, IRP, and the Renewables Portfolio Standard (RPS) requirements. The further in advance the CCA can assess the needs of a particular customer and the timing of its energization, the better able the CCA is to engage in a thoughtful and dynamic procurement strategy.

A dynamic procurement strategy includes purchasing energy in long, medium, and short-term markets to ensure that the CCA can cost-effectively meet the needs of its customers without unnecessary reliance on any one market. However, a dynamic procurement strategy is reliant on good data. Without timely information about potential new load, and in particular Large Loads, and the timing of interconnection, the CCA could under or over procure, increasing risk to its supply portfolio and customers.

As it stands now, CCA procurement strategies begin with the load forecast in the IEPR as well as CCA internal load forecasting, which become more refined over time as better information about individual customers becomes available. The challenge with this

[27] PG&E Response to Interim Implementation Ruling, at 8.

approach is that "better information," including information on Large Loads, has not been made available to CCAs by PG&E until an advice letter is submitted, which is too late. Going forward, to ensure that CCA procurement strategy results in the lowest possible cost to ratepayers, it is necessary to ensure that Large Load information known by PG&E as the delivery service provider is shared at the earliest possible point with CCAs. This information can inform the IEPR load forecast, and it can be used to inform the load forecast used for procurement over time.

The IEPR forecast materially impacts CCAs compliance requirements. Substantial and sudden changes to CCA forecasts can increase RA requirements with limited notice. IEPR forecasts have also historically been used to determine Load Serving Entity (LSE) procurement requirements and, depending on the outcome of the ongoing Reliable Clean Power Procurement Program (RCPPP), may continue to be used for this purpose. In both cases, these compliance requirements endure regardless of whether the load comes to fruition.

While RPS compliance is not directly impacted by the IEPR process, failure for LSEs to accurately predict their own load could significantly impact the entity's ability to remain compliant. This is especially true for compliance with Senate Bill (SB) 350,[28] which requires LSEs to have sufficient long-term contracts, many of which are new build and require several years to bring online. If an LSE learns, either through the IEPR or through a new customer energizing, of significant new load too late (especially near the end of a compliance period), it may materially impact their ability to comply. These load

[28] SB 350 (DeLeón, Ch. 547, Statutes of 2015).

forecast issues may also materially impact an IOU's Energy Resource Recovery Account (ERRA) forecast, and resulting Power Charge Indifference Adjustment charges.

A document recently presented by the CEC underscores these points. The IEPR forecast for data centers includes projects that have: (1) active applications with completed or to-be-completed engineering studies; (2) active applications prior to initiating engineering studies; and (3) project inquiries.[29] The latter two categories included in the forecast count for thirty-eight percent of the total projected capacity for PG&E.[30] PG&E, however, acknowledges that this load remains uncertain, assigning confidence intervals to the forecast load.[31] Including uncertain load is important for planning. However, including such load can also lead to planning for load that never arrives, leaving an LSE potentially on the hook for a long position. Without access to the customer-specific information, the CCA is unable to assess for itself and its own procurement portfolio how certain that load is and what changes to procurement strategy may be required.

The IEPR forecast also fails to provide any detail on the new load and the individual needs of the customer. For instance, a new customer may be intending to purchase its own specific product (*e.g.,* 24/7, carbon free), which would impact the procurement choices made on behalf of the customer. Details on ramp schedule, load type and interconnection schedule will also impact the type and timing of the procurement and should be made known to CCAs at the time PG&E has the information. There should be no material difference in the amount of time PG&E, as the delivery

---

[29] *See* CEC, "Data Center Forecast" (Dec. 23 2024), at 3: https://www.energy.ca.gov/sites/default/files/2024-12/Data_Center_Forecast_Update_ada.pdf.

[30] *Ibid*.

[31] *Id*. at 4.

service provider, has customer-specific information and the amount of time CCAs have the same customer-specific information. The more notice available, the more competitive the CCA (or PG&E, if the customer opts for bundled service) can be in its procurement. This will result in cost savings for all customers.

Only receiving notice of Large Loads during the IEPR process is insufficient for procurement decision-making. PG&E's IEPR forecast does not provide information that allows the CCA to: (1) independently determine the relative certainty of new Large Load; and (2) modify load forecasts to reflect the evolving needs of the customer.

C. Insufficient Information-Sharing Disadvantages CCAs and Harms CCA Customers

As the delivery service provider for customers in its territory, PG&E is often the first stop for a new Large Load considering locating a facility in California. By withholding the customer information required for load planning, PG&E impedes cost-effective procurement by the affected CCA. As described below, the lack of information regarding planned Large Loads creates the following disadvantages for CCAs and CCA customers: (1) lack of competitive parity between CCAs and PG&E; (2) inadequate information to plan for reliability; (3) lack of notice to customers of their generation service options; and (4) inability to capitalize on affordability benefits of cost-effective procurement.

<u>Competitive concerns</u>: To maintain competitive parity between an affected CCA and PG&E, there should be explicit rules ensuring the affected CCA has the same information available to PG&E regarding Large Loads. Failure to do so allows PG&E potentially to be able to use its exclusive role as delivery provider to preference PG&E's

procurement department. As one example, at a recent technical conference at the Federal Energy Regulatory Commission (FERC) on RA, Gillian Clegg, Vice President, Energy Policy and Procurement at PG&E stated "I think what we're saying publicly now is 12.8 gigawatts (GW) of applications have been submitted and about 1.4 GW of that is already through final engineering and so we do think about 90 percent of what's in final engineering will come to bear."[32] That the head of PG&E's procurement department has a defined confidence level in the PG&E forecast implies a degree of certainty in the load which no CCA procurement team can have given their forecasters lack any information to develop any assurance these loads will come online. The Commission should therefore affirm in this proceeding that PG&E and affected CCAs obtain information on new Large Load concurrently. Specifically, CCAs should receive such information within a reasonable amount of time (20 calendar days) after PG&E's delivery service team receives information on new Large Load.

Reliability Concerns: Key Large Load Information is necessary for CCAs' resource planning purposes. Without this information, CCAs are unable to validate or assure that a particular customer's load is included in the IEPR load forecast. As a result, unvalidated information could be used to set the RA or IRP requirements for the CCA. This is problematic on a number of fronts, including affordability. However, as it relates to reliability, unvalidated information can lead to a CCA planning for less resources to satisfy RA requirements than necessary. To properly align planning with realistic load forecasts, a CCA should have all relevant customer information necessary to afford the

[32] FERC Docket AD25-7-000, "Day 2: Commissioner-led Technical Conference Regarding the Challenge of Resource Adequacy in RTO and ISO Regions," (June 5, 2025), at 5:33, video recording available at: https://ferc.gov/news-events/events/day-2-commissioner-led-technical-conference-regarding-challenge-resource (transcribed from video).

opportunity to investigate on its own behalf the certainty of the load. The customer's chosen provider, CCA or PG&E, should be provided sufficient time to ensure reliability requirements are met cost-effectively.

Customer Notice: Customers may not be aware that a CCA serves a location targeted for development. PG&E should be transparent regarding the customer's option at the time of an Interconnection Application. Customers should be aware that the CCA will be their generation service provider subject to the customer's choice to opt out of CCA service. Regardless of whether the customer is aware of the potential for CCA service, the customer may not be aware of the need for the CCA to have early notice of their new load. CCAs should have the opportunity to educate their presumptive customers on the role of the CCA.

Affordability: As described throughout this section, ultimately all customers benefit when the affected CCA and PG&E have sufficient notice of new loads, and especially Large Loads. A longer runway for new procurement requirements enables the affected CCA or PG&E, to cost-effectively procure for the new load. Without sufficient notice, the generation provider will have to rely on the riskier short-term market, which could result in higher prices for customers. In short, reasonable requirements for timely information sharing empowers the affected CCA or PG&E to cost-effectively procure generation for new Large Loads.

To promote cost-effective and equitable procurement, PG&E should be directed to provide information on new Large Loads to the CCA promptly upon receipt of notice of or an Interconnection Application. Legal requirements and customer relationships already require that the CCA protect customer confidentiality. Any customer information provided to CCAs by PG&E will be treated consistent with California law, rules established by the Commission, and pursuant to the applicable NDA with PG&E.

IV. THE COMMISSION SHOULD ADOPT A FRAMEWORK FOR TIMELY INFORMATION-SHARING BY PG&E FOR NEW LARGE LOADS

This testimony recommends that an information-sharing framework between PG&E and any applicable CCA be adopted in connection with the Rule 30 Tariff. As set forth below, this information-sharing framework will: (1) ensure a CCA serving the location of a proposed new Large Load receives quarterly information regarding customers seeking information regarding interconnection with PG&E's transmission system; (2) require PG&E to provide affected CCAs with Interconnection Applications, including Key Large Load Information, within 20 calendar days of PG&E's receipt (and requires already submitted Interconnection Applications to be provided to the affected CCAs); and (3) require PG&E to provide quarterly updates on the status of Interconnection Applications and any changes to Key Large Load Information. In addition, the Commission should require changes to the proposed Rule 30 tariff and form Interconnection Application to effectuate such information sharing, as set forth in redlines attached hereto as Appendix A.

A. The Commission Should Adopt a Framework for Information-Sharing Between PG&E and the CCA with Clear Notice to the Potential Customer

As explained in Section II above, the CCA is the default generation service provider to new customer load sited in the CCA service area. As demonstrated in Section III, sufficient advance notice of new Large Load is required to ensure that the Large Load can be served cost-effectively and equitably. Further, the affected CCA requires ongoing information on any changes to the interconnection timeline and Key Large Load

Information for a new facility. Consistent with these facts, the Commission should adopt the following framework for information- sharing between PG&E and the affected CCA:

- For loads for which no Application for interconnection service under Rule 30 (Interconnection Application) has been filed, but a load inquiry has been made to PG&E and the utility is incorporating the forecast into internal or external forecasts, PG&E should report to CCAs on a quarterly basis the approximate location, size, and anticipated timeline for integrating the new load. Information should be provided on a per-project basis with a unique identifier that protects the customer's identity if the customer does not wish to have their information shared with the CCA.

- When an Interconnection Application has been submitted, PG&E should provide each affected CCA a copy of the Interconnection Application within 20 calendar days of submission to PG&E, with Key Large Load Information. PG&E should also provide all already submitted Applications for Interconnection, and any additional Key Large Load Information, to an affected CCA within 20 calendar days of a Commission directive to do so.

- PG&E should provide each affected CCA with quarterly reports that provide updates on the proposed interconnection timelines related to Interconnection Applications, and any changes to Key Large Load Information.

PG&E has stated in discovery that it is "willing to work with the Joint CCAs on the appropriate information to be provided by PG&E to potential transmission level customers during the Electric Rule 30 application process."[33] The above-described requirements provide a reasonable framework for PG&E to provide necessary and timely customer information to affected CCAs.

B. Proposed Rule 30 Requires Clarification of the Respective Roles of the CCA and PG&E, Information to be Provided to Customers Regarding Customer Choice, and Information to be Provided to CCAs as Default Providers

[33] *See* PG&E Answer to Data Request Joint CCAs_001-Q007, Question 07 (Jan. 29, 2025) (attached hereto in Attachment C).

Consistent with the proposed information-sharing requirement described above, the approved Rule 30 tariff and any form Interconnection Application associated with Rule 30 should also notify customers that if the proposed load is sited in a CCA's service area the affected CCA is the default provider of generation service. In addition, the customer should be informed that, in light of this role and responsibility, the affected CCA is entitled to and will receive information on the customer. The Commission should direct PG&E to add the following language to Section 1. General of proposed Rule 30, as reflected in the Rule 30 Tariff redline attached hereto as Appendix A:

> 8. For any Facility at a location within the service area of a Community Choice Aggregator (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 a Facility in a CCA's service area, PG&E will provide the affected CCA a copy of the Application within 20 calendar days of receipt, to ensure the CCA receives key information about the service request to inform the CCA of the new customer, including the customer name, location, facility type (e.g., data center, commercial, retail, manufacturing), capacity ramp schedule, on-site generation, and requested timing for the interconnection. PG&E will also provide to the affected CCA within 20 calendar days any subsequent changes to the Application and periodic updates to the interconnection timeline. Information provided by PG&E to the CCA is subject to confidentiality protections established by the Commission.

Additionally, ambiguity exists in the Rule 30 Tariff language regarding the definition of "Retail Service." The proposed Rule 30 Tariff definition of Retail Service is the following:

> "RETAIL SERVICE: Electric service to PG&E's end-use or retail customers which is of a permanent and established character and may be continuous, intermittent, or seasonal in nature."[34]

[34] Proposed Rule 30 Tariff, at 17.

Given the concerns of customer awareness discussed in Section III above, the proposed Rule 30 Tariff should be updated to clarify the role of the CCA as the default generation service provider and PG&E's role as the default delivery service provider. PG&E stated in discovery that it is amenable to making this change:

> PG&E is willing to work with the Joint CCAs to clarify that the term "Retail Service" does not include or relate to generation service. As an initial proposal, PG&E suggests adding the following sentence to the defined term "Retail Service":
>
> <u>For purposes of this Rule, Retail Service does not include or relate to providing generation service and/or the electric commodity.</u>[35]

PG&E's proposed clarification should therefore be incorporated into Rule 30, as reflected in CalCCA's redline attached hereto as Appendix A.

The Commission should also direct PG&E to include in its proposed Rule 30 Interconnection Application language consistent with these redlines and the proposed information-sharing requirements. In addition, the Interconnection Application should provide a tool to assist the applicant to determine if the proposed facility will be in a CCA's service area. For any proposed facility in a CCA's service area, PG&E should provide information on how to contact the CCA and, as noted above, clear disclosures that the information will be provided to the affected CCA as the facility's default provider of generation service.

California customers will benefit from new loads choosing to site new facilities in the state. Clear policies and procedures, as well as the benefit of choice, are most likely to encourage these facilities to site in California while protecting existing customers. The changes described herein will also ensure competitive parity between PG&E and CCAs

---

[35] PG&E Response to Data Request Joint CCAs_001-Q006, Question 06. *See* PG&E Answer to Data Request Joint CCAs_001-Q006, Question 06 (Jan. 29, 2025) (attached hereto in Attachment C).

in serving new Large Loads. Improved information sharing and cooperation will maximize the ability of both the CCAs and PG&E to serve these new customers.

APPENDIX A
TO
AMENDED TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY FOR APPROVAL OF ELECTRIC RULE 30 FOR TRANSMISSION-LEVEL RETAIL ELECTRIC SERVICE

REDLINES TO PG&E'S PROPOSED ELECTRIC RULE 30

APPENDIX A

TO

AMENDED TESTIMONY OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY FOR APPROVAL OF ELECTRIC RULE 30 FOR TRANSMISSION-LEVEL RETAIL ELECTRIC SERVICE
A.24-11-007

PROPOSED REDLINES TO
PACIFIC GAS AND ELECTRIC COMPANY
PROPOSED ELECTRIC RULE NO. 30: RETAIL SERVICE TRANSMISSION FACILITIES

Proposed text deletions show as **~~bold and strikethrough~~**
Proposed text additions show as **bold and underlined**

A. GENERAL

8. For any Facility at a location within the service area of a Community Choice Aggregator (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 a Facility in a CCA's service area, PG&E will provide the affected CCA a copy of the Application within 20 calendar days of receipt, to ensure the CCA receives key information about the service request to inform the CCA of the new customer, including the customer name, location, facility type (e.g., data center, commercial, retail, manufacturing), capacity ramp schedule, on-site generation, and requested timing for the interconnection. PG&E will also provide to the affected CCA within 20 calendar days any subsequent changes to the Application and periodic updates to the interconnection timeline. Information provided by PG&E to the CCA is subject to confidentiality protections established by the Commission.

G. DEFINITIONS FOR RULE 30

RETAIL SERVICE: Electric service to PG&E’s end use or retail customers which is of a permanent and established character and may be continuous, intermittent, or seasonal in nature. **For purposes of this Rule, Retail Service does not include or relate to providing generation service and/or the electric commodity.**

ATTACHMENT A
TO
AMENDED TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY FOR APPROVAL OF ELECTRIC RULE 30 FOR TRANSMISSION-LEVEL RETAIL ELECTRIC SERVICE
A.24-11-007

CURRICULUM VITAE OF LORI MITCHELL

LORI MITCHELL

SKILLS

- Executive Leadership
- Clean Energy
- Utility Operations
- Technical Advising
- Local Government
- Problem Solving

BOARD POSITIONS

California Community Power, President, previous Vice Chair

California Community Choice Association, previous President

California Foundation on the Environment and the Economy

EDUCATION

Cal Poly, Humboldt State University:

BS: Engineering

Texas A&M: MBA

PROFESSIONAL SUMMARY

Executive professional with more than 25 years of experience in utilities and renewable energy. Expert in clean energy, utility operations, and management. Proven relationship builder with stakeholders, elected officials, and staff. Recognized for track record of success in building and leading high performing organizations.

WORK HISTORY

CITY OF SAN JOSE, ENERGY - Director

San Jose, CA • 11/2017 - Current

- Successfully worked with the Mayor, City Council, and the City Manager's office to start-up a new Department providing electric generation service under the community choice aggregation model.
- San Jose Clean Energy serves 350,000 customers and has saved ratepayers more than $50 million dollars while providing over 60% renewable energy.
- Successfully negotiated power supply agreements totally over 1GW of new renewable projects valued at over $4 billion dollars.
- Successfully managed an operating budget of over $500 million a year and ensured regulatory compliance with the CPUC, CEC, CAISO as well as other agencies.
- Hired, trained, and onboarded over 60 staff
- Provided executive leadership to form a new municipal utility to support data centers including managing the interconnection and electrical distribution design.

CITY OF SAN JOSE, ESD - Acting Director

San Jose, CA • 8/2024 – 3/17/25

- Provided executive leadership to oversee the Environmental Services Department which includes over 600 staff and operates retail water, regional wastewater facility, recycling and garbage services, stormwater, and other utility services.

CITY Of SAN FRANCISC0, SFPUC Multiple Positions, ending in Director

San Francisco, CA • 2007 - 2017

- Provided executive leadership to synchronize efforts across: Power Supply and Scheduling; Renewable Generation; Energy Efficiency; Distribution and Transmission Planning.
- Successfully managed a $500 million capital budget to ensure projects were completed within budget. Projects included solar, energy efficiency, and initial designs for the Bay Corridor Transmission and Distribution project located on the southeast side of the city.
- Led negotiations for the energy contracts to support the launch and growth San Francisco's CleanPowerSF Community Choice Aggregation Program valued at $100 Million dollars.
- Managed SF's Hetch Hetchy hydroelectric assets to optimize power production within the constraints of the water supply systems.
- Successfully represented the Department at public meetings with the SF Board of Supervisors and the SF Public Utilities Commission to obtain project approvals and discuss critical issues.
- Built high performing teams and successfully managed a team of over 100 people to achieve the agencies strategic business goals.
- Strategically led the team in constructing the largest municipal solar project located in an urban environment.
- Led the power supply and scheduling group responsible for power trading and scheduling 385 MW of hydroelectric generation into the CAISO market.
- Provided oversight for the implementation of the City's renewable energy program that consisted of solar PV, wind, wave, and small hydro projects.
- Achieved $6M in savings by streamlining forecasting procedures and implementing cost reduction strategies for energy purchases and services as well as increasing coordination with the CAISO scheduling and settlements groups.

POWERLIGHT / SUNPOWER CORPORATION - Senior Engineer
Berkeley, CA • 1999 - 2007

- Oversaw the power modeling of various utility-scale solar projects, including a 10MW project in Germany, a 15 MW project in Portugal, 20 MW in Spain, and several smaller rooftop projects in the United States.
- Resolved performance and operational issues of hundreds of solar projects to meet performance specifications.
- Controlled engineering activities to maintain work standards, adhere to timelines and meet quality assurance targets.
- Produced and presented multiple technical papers in various industry conferences.
- Educated clients on the energy production and performance of their solar project.

NATIONAL RENEWABLE ENERGY LABORATORY
Washington, DC • 1998

CALIFORNIA ENERGY COMMISSION
Sacramento, CA • 1997

CALIFORNIA AIR RESOURCES BOARD
Sacramento, CA • 1996

LICENSE
California Professional Engineer (PE): Mechanical

AWARD:
Silicon Valley Business Journal: Women of Influence 2023

PUBLICATIONS
Authored multiple technical papers on the performance of solar energy projects, published in IEEE journals

ATTACHMENT B
TO
AMENDED TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY FOR APPROVAL OF ELECTRIC RULE 30 FOR TRANSMISSION-LEVEL RETAIL ELECTRIC SERVICE
A.24-11-007

CURRICULUM VITAE OF KRIS VAN VACTOR

S. Kris Van Vactor

5850 Balcom Ave., Encino, CA 91316
503-544-5142 | kris.vanvactor@gmail.com

Professional Profile

Results-oriented leader in procurement, policy, and energy market strategy with over 20 years of experience spanning utility operations, regulatory policy, wholesale energy markets, and economic consulting. Proven success in managing multidisciplinary teams, leading major market transitions, and negotiating complex energy contracts. Skilled in economic analysis, project implementation, and cross-functional collaboration in regulated and deregulated energy environments.

Core Competencies

Strategic Energy Procurement, Policy Analysis & Regulatory Affairs, Team Leadership & Development, Economic & Statistical Analysis, Program & Project Management, Technical Writing & Reporting, Contract Negotiation, Contract Management, Organizational Budgeting, Procurement Planning, Market Operations (CAISO, FERC), Resource Adequacy, Energy Hedging, Software: Microsoft Office, VBA, eViews

Professional Experience

Director of Power Resources

Silicon Valley Clean Energy (SVCE), Sunnyvale, CA
2024 – Present

• Lead an organization of procurement professionals that specialize in Front-office, Back-office and Planning activities

• Oversaw the management of a clean portfolio of generation assets with contracts totaling ~2 billion

• Provide strategic guidance for short-term and long-term procurement needs

• Assess and manage group functions and needs as workflow dictates

Wholesale Energy Markets Manager

Silicon Valley Clean Energy (SVCE), Sunnyvale, CA

2022 – 2024

• Lead procurement and operations for energy hedging and Resource Adequacy.

• Oversaw transition to CAISO's "Slice of Day" RA market structure

• Represent SVCE in stakeholder forums (CalCCA and others)

• Led joint negotiations for a 100 MW New Mexico wind import (SunZia project).

• Supported integration of long-term renewable contracts (e.g., Yellow Pine, Victory Pass).

Senior Project Manager/Senior Advisor, CAISO Settlements

Southern California Edison (SCE), Rosemead, CA
2017 – 2022

• Spearhead policy, strategy and implementation of products for use in organized energy markets

• Uphold role as workgroup representative on simultaneous projects while assuring the completion of project-specific goals, milestones and timelines

• Identify and implement various CAISO based initiatives including changes to Congestion Revenue Rights settlements, Market Settlement Timeline Transformation, Intertie Deviation Settlement and CAISO Summer Readiness changes

• Identified a policy gap where energy storage resources were being charged Resource Adequacy Availability Incentive Mechanism despite bidding their full capacity

• Represented SCE Back office in internal and external market design and policy forums.

Project Manager

Southern California Edison (SCE), Rosemead, CA
2013 - 2017

• Identified changes and implemented them in order to support market changes initiated by CAISO including updated Capacity Procurement Mechanism and Reliability Services Initiative rules as well as Full Network Model Expansion.

• For each project identified software needs, tracked development and adjusted timelines accordingly

• Developed a strategic framework for bidding standalone batteries into CAISO marketplace

• Onboarded 92 MW of aggregated distribution level solar resources into CAISOs market.

•Represented SCE Front office in internal and external market design and policy forums.

Energy Operations Specialist

Southern California Edison (SCE), Rosemead, CA
2011 - 2013

• Developed a position report to track various market specific metrics for real-time traders

• Provided project support on a variety of projects

• Onboarded renewable resources into Southern California Edison's generation portfolio

Senior Financial Analyst

Southern California Edison (SCE), Rosemead, CA
2009 - 2011

• Developed and implemented strategies and software changes for Virtual Bidding

• Provided project support on a variety of projects

Economist / Reporter

Economic Insight, Inc., Portland, OR
2004 – 2009

• Conducted analysis on natural gas costs and energy contract valuations.

• Published and edited "Energy Market Report" newsletter tracking market dynamics.

• Developed automated data workflows, improving analytical efficiency.

Sales and Marketing Manager

E-Business International, Inc., Beaverton, OR
2000 – 2002

• Managed supply chain strategies and client development.

• Initiated and executed successful cross-border supply chain projects connecting U.S. companies with Chinese manufacturers.

Education

Bachelor of Science in Economics
University of Oregon, Eugene, OR

2003

Additional Information

• Technical Skills: Microsoft Office Suite, VBA, eViews

• Languages: English (native)

• Professional Affiliations: Participant in CalCCA and other energy policy coalitions

• Public Engagement: Regular contributor in public energy forums and stakeholder discussions

ATTACHMENT C
TO
AMENDED TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY FOR APPROVAL OF ELECTRIC RULE 30 FOR TRANSMISSION-LEVEL RETAIL ELECTRIC SERVICE
A.24-11-007

SELECT DISCOVERY RESPONSES

PACIFIC GAS AND ELECTRIC COMPANY
Electric Rule 30 – Transmission-Level Interconnections
Application 24-11-007
Data Response

PG&E Data Request No.:	JointCCAs_001-Q001
PG&E File Name:	ElectricRule30-Transmission-LevelInterconnections_DR_JointCCAs_001-Q001
Request Date:	January 23, 2025
Requester DR No.:	001
Requesting Party:	JointCCAs
Requester:	Scott Blaising
Date Sent:	January 29, 2025
PG&E Witness(es):	Karen Khamou Ornelas – Engineering, Planning and Strategy

QUESTION 001

In its Prepared Testimony ("**PG&E Testimony**"), PG&E states that it "has seen a significant increase in applications for transmission level interconnections for new retail electric customers. Since 2023, PG&E has received 34 applications for transmission level service with demand of 4 MW or greater…. The total combined load of the 34 applications is 4,440 MW." (PG&E Testimony at 1-4.)

a. For the 34 applications, please indicate whether (and if so, how and when) PG&E provided notice of the applications to the affected community choice aggregators ("**CCAs**") in whose service area the new retail customers were to be located ("**Potentially Affected CCA**").

b. Please describe the process that PG&E currently follows to provide notice to Potentially Affected CCAs of new applications for service by very large (i.e., 4 MW or greater) retail customers ("**Mega Customers**").

c. As related to issues in this proceeding, is PG&E amenable to developing a formal procedure or amending its proposed Rule 30 to include a written process by which PG&E provides advance and continuing notice to Potentially Affected CCAs of applications for transmission service by Mega Customers?

   i. If not, please explain why PG&E is not amenable.

   ii. If so, please further describe, including a description of what information PG&E would provide, when and under what terms and conditions.

ANSWER 001

a. The applications described in PG&E's testimony concern the physical interconnection of a facility into PG&E's electrical system. These applications do not concern the provision or procurement of electric commodity service. Thus, PG&E did not provide notice to energy providers such as Community Choice Aggregators (CCAs) or Direct Access (DA) providers. In addition, the applications often include commercially sensitive customer information that is not shared outside of PG&E.

b. PG&E objects to term “mega customers” and will not use this terminology in its response. Subject to this objection, *see* subpart (a).

c. Given the issues in this proceeding and the need for a timely Commission determination on Electric Rule 30, PG&E does not believe that communications with CCAs or DA providers regarding new transmission level customer interconnections should be in scope in the proceeding. However, PG&E would be supportive of working with the CCAs and other procurement providers to develop written procedures regarding such communications and then submitting these procedures to the CPUC through a separate advice letter.

PACIFIC GAS AND ELECTRIC COMPANY
Electric Rule 30 – Transmission-Level Interconnections
Application 24-11-007
Data Response

PG&E Data Request No.:	JointCCAs_001-Q002
PG&E File Name:	ElectricRule30-Transmission-LevelInterconnections_DR_JointCCAs_001-Q002
Request Date:	January 23, 2025
Requester DR No.:	001
Requesting Party:	JointCCAs
Requester:	Scott Blaising
Date Sent:	January 29, 2025
PG&E Witness(es):	Karen Khamou Ornelas – Engineering, Planning and Strategy

QUESTION 002

In the PG&E Testimony, PG&E states that it “is presently conducting a pilot program for a cluster process for new transmission level retail electric customers located in Alameda and Santa Clara Counties.” (PG&E Testimony at 1-6.)

a. Please indicate whether the Potentially Affected CCAs have been informed of the pilot program. If so, please provide supporting information.

b. Please provide further information on the pilot program, including (but not necessarily limited to) its intended results, its current status, whether Commission review is anticipated, and its relevance, if any, to PG&E’s request in this proceeding.

c. As related to issues in this proceeding, is PG&E amenable to including the Potentially Affected CCAs in a working group with PG&E for the purpose of providing timely, non-public information on the pilot program?

   i. If not, please explain why PG&E is not amenable.

   ii. If so, please describe how PG&E might structure and implement a working group for the sharing of timely, non-public information about the pilot program.

ANSWER 002

a. *See* PG&E’s response to Question 1(a). Given that the Pilot Cluster Process involved the interconnection of new electric customers, not the procurement of the electric commodity, PG&E did not provide notice directly to Community Choice Aggregators (CCAs). However, PG&E has provided information in this proceeding regarding the Pilot Cluster Process which is equally available to CCAs.

b. PG&E provided the following information in response to Cal Advocates Data Request Set #1, Question 6:

In 2024, PG&E piloted a cluster study approach to study the increased number of data center applications received in the San Francisco South Bay area, mainly in Santa Clara and Alameda counties ("Pilot Cluster Process"). The clustering of large data center applications in certain areas and studying them in a serial process created complex, high-cost interconnection, and capacity upgrades. When projects are studied serially, the study timelines are lengthy and often do not study the cumulative impacts of the total load in a geographic area.

PG&E's Pilot Cluster Process is a streamlined approach for handling applications for large data center loads within a specific geographic area, allowing customers to submit applications and be grouped based on their proximity to PG&E's transmission and distribution system. We also offered customers with active or previously completed applications the chance to restudy, downsize, or change their project's Point of Interconnection within the same calendar year. Customer Engagement Meetings have been or will be held during the Pilot Cluster Process to provide each customer a dedicated meeting where PG&E and the customer can discuss feasible connection options, available capacity, land, permitting, and planned capacity projects. This helps customers make informed decisions about proceeding with or withdrawing their applications.

The Pilot Cluster Process also sets clear timelines and procedures for study milestones, customer engagement, and project initiation. Customers will be informed about the expected scope, costs, and duration of their project during the application phase. The Pilot Cluster Process aims to produce meaningful results that consider system capabilities and establish shared cost allocation and responsibility, supporting the development of a consolidated engineering and implementation plan.

PG&E expects that agreements that result from the Pilot Cluster Process will either be approved pursuant to the process proposed in PG&E's interim implementation motion and/or through exceptional case filings at the Commission.

c. Given the issues in this proceeding and the need for a timely Commission determination on Electric Rule 30, PG&E does not believe that sharing non-public Pilot Cluster Process information with CCAs should be in scope in the proceeding. However, PG&E would be supportive of working with the CCAs on sharing information, subject to confidentiality protections, at the appropriate time in the Pilot Cluster Process.

PACIFIC GAS AND ELECTRIC COMPANY
Electric Rule 30 – Transmission-Level Interconnections
Application 24-11-007
Data Response

PG&E Data Request No.:	JointCCAs_001-Q006
PG&E File Name:	ElectricRule30-Transmission-LevelInterconnections_DR_JointCCAs_001-Q006
Request Date:	January 23, 2025
Requester DR No.:	001
Requesting Party:	JointCCAs
Requester:	Scott Blaising
Date Sent:	January 29, 2025
PG&E Witness(es):	Ben Moffat – Engineering, Planning and Strategy

QUESTION 006

In Attachment A to Chapter 2 of the PG&E Testimony, PG&E sets forth a proposed rule that, among other things, contains the following definition for "Retail Service": "Electric service to PG&E's end-use or retail customers which is of a permanent and established character and may be continuous, intermittent, or seasonal in nature." (PG&E Testimony at 2-AtchA-17.)

a. As related to issues in this proceeding, is PG&E amenable to changing the term "Retail Service" to "Retail Delivery Service" or another term that does not imply that the service described in Proposed Rule 30 relates to or includes generation service?
   i. If not, please explain why PG&E is not amenable.
   ii. If so, please provide a description of the revised term that PG&E agrees to use.

ANSWER 006

PG&E is willing to work with the Joint CCAs to clarify that the term "Retail Service" does not include or relate to generation service. As an initial proposal, PG&E suggests adding the following sentence to the defined term "Retail Service":

> For purposes of this Rule, Retail Service does not include or relate to providing generation service and/or the electric commodity.

PACIFIC GAS AND ELECTRIC COMPANY
Electric Rule 30 – Transmission-Level Interconnections
Application 24-11-007
Data Response

PG&E Data Request No.:	JointCCAs_001-Q007
PG&E File Name:	ElectricRule30-Transmission-LevelInterconnections_DR_JointCCAs_001-Q007
Request Date:	January 23, 2025
Requester DR No.:	001
Requesting Party:	JointCCAs
Requester:	Scott Blaising
Date Sent:	January 29, 2025
PG&E Witness(es):	Ben Moffat – Engineering, Planning and Strategy

QUESTION 007

In D.22-11-009, the Commission clarified that PG&E's substation microgrid solutions "does not impact a customer's choice of, or experience with, their [CCA]." (D.22-11-009 at 62.)

a. As related to issues in this proceeding, is PG&E amenable to providing advance notice to customers (at the earliest stages of the proposed Rule 30 process) that, among other things, identifies the CCA for the customer's service location, describes the role that CCAs play in providing electric generation service to customers in their respective service areas, provides contact information (supplied by the CCA) for the CCA, and clearly states that the customer's application for and election of transmission delivery service does not impact the customer's rights with respect to electric generation service provided by the CCA?

   i. If not, please explain why PG&E is not amenable.

   ii. If so, please identify where in the proposed Rule 30 stages PG&E would propose adding customer notification about these CCA-related matters.

ANSWER 007

PG&E is willing to work with the Joint CCAs to develop a procedure by which, during the Electric Rule 30 process, PG&E explains to an applicant that interconnection under Electric Rule 30 does not "impact a customer's choice of, or experience with" a CCA or other energy provider such as a Direct Access provider. PG&E is willing to work with the Joint CCAs on the appropriate information to be provided by PG&E to potential transmission level customers during the Electric Rule 30 application process.

PACIFIC GAS AND ELECTRIC COMPANY
Electric Rule 30 – Transmission-Level Interconnections
Application 24-11-007
Data Response

Request Date:	March 28, 2025
Requesting Party:	Joint CCAs
Requester:	Scott Blaising
Date Sent:	April 10, 2025

QUESTION 001

Please provide a description of and associated timelines for expected activities under proposed Rule 30 (including, but not necessarily limited to, activity related to the submittal of an application, preliminary study, design review, engineering, interconnection agreement, procurement, construction and energization). The preceding examples are intended to be general descriptions of certain activity, and PG&E should not feel limited by these descriptions; PG&E may use whatever terminology it believes is most appropriate so long as PG&E's response describes expected activities and provides associated timelines for these activities. As much as reasonably possible, the Joint CCAs request that PG&E describe activities in a sequential manner.

ANSWER 001

PG&E's large load interconnection process includes a number of phases: application, preliminary engineering study, design, preconstruction, construction, and closeout. These phases can be described as the following:

- Application Phase: The customer submits a service energization request and a study deposit.
- Preliminary Engineering Phase: PG&E defines the initial scope of analysis and performs studies to determine service options and initial costs.
- Design Phase: PG&E and the customer agree on the scope of work, creating a project design and refining the project cost.
- Preconstruction Phase: This phase confirms dependencies between the customer and PG&E, including obtaining necessary permits and easements.
- Construction Phase: PG&E schedules and completes all construction activities, including traffic control and scheduling outages.
- Closeout Phase: All inspections are completed, and the site is energized, allowing the customer to start receiving service.

While this process is generally sequential, certain components, such as design and preconstruction, can occur concurrently. The associated timelines are not solely under PG&E's control and depend on customer decisions, agency permit timelines, and land negotiations. As noted in our Application, until 2023, PG&E had a limited number of customers requesting retail electric service at transmission-level voltages. Infrequent requests for transmission-level interconnections were addressed through exceptional case filings. However, starting in 2023, the number of customers requesting transmission-level service began to significantly increase.

As we continue to refine our load interconnection processes, we lack the granularity to provide specific timelines for each phase. Nevertheless, the Preliminary Engineering Phase is planned to take 200 calendar days. Additionally, many projects require upstream capacity upgrades, which often involve more complex work. The CPUC has recently adopted the following maximum statewide timelines[1] for upstream capacity projects, based on the lowest average among the three investor-owned utilities:

- New or upgraded circuit: 684 calendar days
- Substation upgrade: 1,021 calendar days
- New substation: 3,242 calendar days.

Attachment C-8

[1] D.24-09-020 at 47.