

MARCH FILINGS

Docket No.: A.24-09-014

Exhibit No.: _____

Date: March 9, 2026

Witness: Kyra J. Coyle

**PREPARED DIRECT TESTIMONY OF KYRA J. COYLE
ON BEHALF OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION
IN PG&E'S GENERAL RATE CASE PHASE II APPLICATION**

EXECUTIVE SUMMARY OF RECOMMENDATIONS

This testimony presents the recommendations of CalCCA¹ concerning certain issues in the ! ""#%&'()*+,-./:;<=>?@A B C D E F G H I J K L M N O P Q R S T U V W X Y Z [\] ^ _ ` a b c d e f g h i j k l m n o p q r s t u v w x y z { | } ~ ¡ ¢ £ ¤ ¥ ¦ § ¨ © ª « ¬ ® ¯ ° ± ² ³ ´ µ ¶ · ¸ ¹ º » ¼ ½ ¾ ¿ (4 " & 5 * (6 1 7 \$ 1 % . 0 # % 2 \$ % 8 & 9 \$) # 3 (. ' : 6 1 7 1) ; 1 * ! # % & ' () : ; < / 6 & 1 < 1 . \$) , submitted on September 30, 2024.

CalCCA recommends the Commission:

- Reject PG&E’s proposed 20 percent increases to its CCA Service Fees;
- Order PG&E to complete a cost study to support any future recommended changes to its CCA Service Fees;
- Order PG&E to (1) cap its revenues associated with the CCA Service Fees at the cost levels included in its forecast for these services provided in its 2027 Phase I GRC Application 25-05-009, and (2) track any revenue received above that cap and refund this amount to unbundled customers via PG&E’s next ERRA compliance proceeding;
- Reject PG&E’s proposal to update its CCA Service Fees via Tier 2 Advice Letters in the future, and instead reiterate that PG&E may only update these fees via a GRC application, and that any such update must be supported by up-to-date information regarding PG&E’s actual costs incurred in the provision of these services; and
- Direct PG&E to update its POLR fee for CCA customers by: (1) ordering PG&E to submit supplemental testimony in this proceeding regarding its actual method and costs to process a mass involuntary return of customers to bundled service in 2026, using up-to-date data that reflects the economies of scale that would be achieved in a mass return; (2) allowing intervenors the opportunity to submit rebuttal testimony responsive to PG&E’s supplemental testimony on this topic in this proceeding, and scheduling evidentiary hearings on this issue; and (3) ordering PG&E to submit testimony in its next GRC application immediately following the implementation of its BMI project regarding its actual method and costs to process a mass involuntary return of customers to bundled service using PG&E’s new billing system, using up-to-date data that reflects the economies of scale that would be achieved in a mass return.

¹ Acronyms and defined terms used in this Summary of Recommendations are defined within the body of this testimony.

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1 **I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS**

2 **Q: Please state your name, position, and business address.**

3 A: My name is Kyra Coyle. I am a Principal at NewGen Strategies and Solutions, LLC. My
4 business address is 225 Union Boulevard, Suite 450, Lakewood, Colorado 80228.

5 **Q: Please describe your experience and qualifications.**

6 A: I have over 15 years of experience in the utility, mining, and public accounting sectors. My
7 expertise includes utility revenue requirement analyses, strategic planning, project
8 management, contract negotiations, financial modeling, regulatory affairs, budgeting,
9 forecasting, and regulatory accounting. My rate-related projects have included studies to
10 develop retail electric, natural gas, transmission, ancillary service, standby, and special
11 contract rates. I have provided expert witness testimony before several public utility
12 commissions, including those in Alaska, Texas, California, Utah, Oregon, Indiana, and
13 Wyoming, as well as before the Federal Energy Regulatory Commission (FERC). A
14 summary of my qualifications is provided within **Attachment KJC-1** to this testimony.

15 **Q: On whose behalf are you testifying?**

16 A: I am testifying on behalf of the California Community Choice Association (CalCCA).
17 CalCCA represents the interests of 24 community choice aggregators (CCAs) in California,
18 including 11 CCAs that serve Pacific Gas and Electric Company's (PG&E) delivery
19 service customers. Each of those CCAs is governed by a Board of Directors comprised of
20 elected officials who represent the individual cities and counties the CCA serves, or an
21 elected City Council. CleanPowerSF is the CCA program developed and operated by the
22 City and County of San Francisco, through the San Francisco Public Utilities Commission.
23 San José Clean Energy is the City of San José's CCA program, which the San José Energy
24 Department administers. CalCCA and CCAs individually advocate for their customers and
25 their local energy programs before the Commission.

26 CCA customers pay CCA-specific generation rates, which vary and are partially
27 influenced by local mandates to increase electric vehicle use, procure and maintain clean
28 electricity portfolios that in many cases exceed state requirements for renewable
29 generation, and achieve other local goals. CCA customers receive generation services from
30 their local CCA, and receive transmission, distribution, billing, and other services from the

1 incumbent investor-owned utility (IOU). In addition, CCA and other unbundled customers
2 are subject to several non-bypassable charges as well as various utility service fees.

3 **Q: What is the purpose of your testimony?**

4 A: This testimony primarily addresses the following issues in the March 21, 2025 !.. \$) I/ *
5 3 (4 4 \$. \$) I2= *% " \$) 9*8 14 (* & / * 6 ; # \$) 9 (Scoping Ruling):²

- 6 1. Whether PG&E's proposed marginal electric costs and cost of service calculations
7 are reasonable and should be approved; and
- 8 3. Whether PG&E's proposed rate designs, including its demand charges, customer
9 charges, dynamic rate options, and proposed time of use periods and seasons, are
10 reasonable and should be approved.

11 Specifically, this testimony focuses on (1) PG&E's proposal to increase its CCA Service
12 Fees³ across the board by 20 percent based on a general labor escalator rather than evidence
13 of the actual costs associated with performing the relevant services; (2) PG&E's request
14 for review of any future CCA Service Fee increases via Tier 2 Advice Letters rather than
15 via formal Commission proceedings; and (3) PG&E's proposal to maintain its Provider of
16 Last Resort (POLR) re-entry fee and Financial Security Requirement (FSR) at its current
17 level despite the dated inputs and assumptions used to develop the current fee.

18 **Q: Can you summarize CalCCA's specific recommendations in this case?**

19 A: CalCCA recommends the Commission:

- 20 • Reject PG&E's proposed 20 percent increases to its CCA Service Fees;
- 21 • Order PG&E to complete a cost study to support any future recommended changes to its
22 CCA Service Fees;
- 23 • Order PG&E to (1) cap its revenues associated with the CCA Service Fees at the cost levels
24 included in its forecast for these services provided in its 2027 Phase I General Rate Case
25 (GRC) Application (A.) 25-05-009, and (2) track any revenue received above that cap and
26 refund this amount to unbundled customers via PG&E's next Energy Resource Recovery
27 Account (ERRA) compliance proceeding;

² !"" A.24-09-014, #\$\$%&' "()*+ , , %\$\$+' "-.\$)!/+0%'&) 1 " , +)2' ()345%' &, pp. 2-3 (March 21, 2025) (Scoping Ruling).

³ A CCA Service Fee is a charge from PG&E for services rendered to non-utility Energy Service Providers (ESP). !""Exh. PG&E-3 at 9-1:9-11.

- 1 • Reject PG&E’s proposal to update its CCA Service Fees via Tier 2 Advice Letters in the
2 future, and instead reiterate that PG&E may only update these fees via a GRC application,
3 and that any such update must be supported by up-to-date information regarding PG&E’s
4 actual costs incurred in the provision of these services; and
- 5 • Direct PG&E to update its POLR fee for CCA customers by: (1) ordering PG&E to submit
6 supplemental testimony in this proceeding regarding its actual method and costs to process
7 a mass involuntary return of customers to bundled service in 2026, using up-to-date data
8 that reflects the economies of scale that would be achieved in a mass return; (2) allowing
9 intervenors the opportunity to submit rebuttal testimony responsive to PG&E’s
10 supplemental testimony on this topic in this proceeding, and scheduling evidentiary
11 hearings on this issue; and (3) ordering PG&E to submit testimony in its next GRC
12 application immediately following the implementation of its Billing Modernization
13 Initiative (BMI) project regarding its actual method and costs to process a mass involuntary
14 return of customers to bundled service using PG&E’s new billing system, using up-to-date
15 data that reflects the economies of scale that would be achieved in a mass return.

16 **II. THE COMMISSION SHOULD REJECT PG&E’S PROPOSED INCREASES TO**
17 **ITS CCA SERVICE FEES AND DENY ITS REQUEST TO CIRCUMVENT**
18 **COMMISSION REVIEW OF FUTURE INCREASES.**

19 **Q: Why is PG&E charging CCAs for service fees?**

20 A: PG&E is the statutorily designated billing agent for the CCAs in its service territory.⁴ As
21 the designated billing agent, PG&E generates and issues bills for both its bundled and
22 unbundled electric customers, including customers of CCAs. PG&E also collects customer
23 bill payments on behalf of CCAs and transfers those payments to the CCAs. PG&E
24 provides specialized metering and billing services to the CCAs and then bills CCAs for
25 these services via the Master Data Management Agent fee, the Rate-Ready Billing fee, and
26 the Bill-Ready Billing fee (collectively, the CCA Service Fees).⁵

⁴ Cal. Pub. Util. Code § 366.2(c)(9).

⁵ Exh. PG&E-3 at 9-2:19-24.

1 **Q: What specific costs do these CCA Service Fees cover?**

2 A: The Master Data Management Agent fee covers PG&E’s costs of providing meter data
3 through PG&E’s Data Exchange Server; this fee is charged per meter per month.⁶ The
4 Rate-Ready and Bill-Ready Billing Service fees are charged per meter, per billing cycle,⁷
5 and cover PG&E’s costs for presenting and processing energy charges and customer
6 payment on behalf of the CCAs.⁸ The services covered by these fees have remained
7 identical across PG&E’s last three Phase II GRC applications.⁹

8 **Q: Why do these fees matter to CalCCA?**

9 A: CalCCA and its member CCAs are the sole advocates for their customers and their local
10 energy programs before this Commission. CalCCA works to ensure that CCA customers
11 are charged just and reasonable rates and are only charged by IOUs for the costs they
12 caused the utility to incur.

13 **Q: What is PG&E proposing in this Application regarding these CCA Service Fees?**

14 A: In this Application, PG&E is proposing a 20 percent increase to each of these CCA Service
15 Fees.¹⁰ It is also requesting that the Commission cease its practice of only updating these
16 service fees via GRCs or other formal rate design proceedings, and instead allow PG&E to
17 propose future escalations to these fees via the Commission’s Tier 2 Advice Letter
18 process.¹¹ The fee increases PG&E proposes in this case are presented in Figure 1 below.

⁶ Exh. PG&E-3 at 9-2:24-26.

⁷ A “Billing Cycle” is “[t]he regular interval at which a bill for electric service is rendered; typically spans a 27-to-33-day period.” PG&E Tariff, Electric Rule No. 1, Sheet 7.

⁸ Exh. PG&E-3 at 9-2:26 to 9-3:3. “Rate-Ready” and “Bill-Ready” are the two types of billing available to PG&E CCAs. “Rate-Ready” accounts operate as follows: the CCA gives PG&E its rates, and PG&E then uses its billing system to calculate the invoice for CCA services. In contrast, “Bill-Ready” accounts operate as follows: PG&E sends the CCA/CCA Data Manager its usage data, and then the CCA/CCA Data Manager calculates the invoice amount and sends PG&E an invoice to be placed on the consolidated bill.

⁹ Attachment KJC-2 (PG&E Response to CalCCA DR 2.15).

¹⁰ Exh. PG&E-3 at 9-1.

¹¹ 6(. at 9-1:16-19.

Figure 1: Community Choice Aggregation Program Service Fees¹²

Line No.	Service Description	Tariff Reference	Fee Type	Current Fee ^(a)	Proposed Fee
1	Composite Master Data Management Agent Fee	Sheet 4: 6a	Per Meter Per Month	\$0.14	\$0.17
2	Composite Rate-Ready Billing Fee	Sheet 6: 8a	Per Account Per Billing Cycle	\$0.21	\$0.25
3	Composite Bill-Ready Billing Fee	Sheet 6: 7a	Per Account Per Billing Cycle	\$0.21	\$0.25

(a) Previously approved by D.18-01-013, p. 12.

A. PG&E’s Proposed CCA Service Fees Are Not Cost-Based and Are Based on an Unjustified and Unreasonable Labor Escalation Factor.

Q: Why is PG&E proposing an increase to the CCA Service Fees in this case?

A: PG&E asserts it is proposing a change to the CCA Service Fees now because the current fees were originally approved in 2018 and were not updated in PG&E’s 2020 GRC II proceeding. Therefore, these fees have not been updated to reflect any changes to PG&E’s costs—such as inflation rate impacts—in over five years.¹³

Q: How does PG&E propose to make this update?

A: PG&E proposes to use an escalation factor to make this update. An escalation factor is a percentage that is usually calculated by examining changes in price index measures for a good or service. PG&E proposes to use escalation rates consistent with the labor escalation rates within the “Average Labor Escalation – 1 All Employees” category for each year presented, filed in PG&E’s 2023 GRC Phase I proceeding.¹⁴

Q: Why is PG&E proposing to use an escalation factor to make this update?

A: PG&E does not provide much justification in its testimony for its proposal to use an escalation factor to increase these fees. PG&E simply notes that applying escalation rates from 2021 through 2025 is, in its view, “appropriate and consistent with D.18-01-013^[15] because, in that decision, the Commission approved PG&E’s current service fees through

¹² 6(. at 9-4 (Table 9-2).

¹³ 6(. at 9-3:16-18.

¹⁴ 6(. at 9-4:8 to 9-5:3.

¹⁵ Decision (D.) 18-01-013, 7"/%\$%+')#(+08%' &)9 : +)! "885" , "' 8\$)3 "528" ()8+); 2/%<(/)=2\$)2' ()>5"/8-%/)*+ , 02' ?. \$)>5"/8-%/) 1 2-&% ' 25)*+\$8\$0)3 "A" ' 4")#55+/28%+' 0)2' ()328") 7 "\$%&' , A.16-06-013 (Jan. 11, 2018).

2020.”¹⁶ In other words, PG&E views the current fees as out-of-date with PG&E’s current costs because they were originally only approved for use through 2020. PG&E’s testimony does not discuss why making updates via the use of an escalation factor would be more reasonable or appropriate than doing so via the use of another methodology.

Q: Can you please summarize why CalCCA is concerned with PG&E’s use of this escalation factor to increase the CCA Service Fees?

A: CalCCA is concerned about PG&E’s proposed use of this escalation factor to increase the CCA Service Fees for five main reasons:

1. Updates made via escalation factors are generally out-of-step with fundamental principles of cost-based ratemaking;
2. Even accepting the false premise that it is generally reasonable for PG&E to update these fees via an escalation factor, it would be unreasonable for PG&E to rely on an escalator in this case given how dated the underlying calculation is;
3. Even accepting the false premise that it is generally reasonable for PG&E to update these fees via an escalation factor, PG&E’s proposal is unreasonable because the particular labor escalator PG&E proposes to use is inappropriate and does not result in a reasonable approximation of actual costs incurred;
4. PG&E admitted in its currently pending Phase I GRC (A.25-05-009) that its current CCA Service Fee levels resulted in it over-collecting costs for these services from CCA customers from 2020 through 2024, thus confirming that a change to the current fee levels is not justified at this time; and
5. PG&E has argued in its pending BMI application proceeding that its BMI project is likely to further improve PG&E’s efficiency in providing these kinds of billing services to CCAs going forward, which suggests that PG&E is likely to incur lower costs in the provision of these services in the near future.¹⁷

I will discuss each of these concerns in more detail below.

¹⁶ Exh. PG&E-3 at 9-4:8 to 9-5:3.

¹⁷ A.24-10-014, ; = B>.\$)C 1 6); -"02-"()9"\$% , + '?, p. 4-45:10-22 (Oct. 23, 2024).

1 **Q: Can you explain in more detail why updates made via escalation factors generally are**
2 **out-of-step with fundamental principles of cost-based ratemaking?**

3 A: A fundamental principle of utility ratemaking is that costs should be allocated in line with
4 cost causation—customers should pay for only those costs they cause the utility to
5 incur.¹⁸ This foundational principle is reflected in California law, Commission precedent,
6 and the leading rate design literature.¹⁹ The service fees charged to CCAs should be no
7 different: they should reflect the actual costs PG&E incurs to perform the relevant services
8 for CCAs.

9 Generally, escalation factors do not comport with this principle because they cause
10 rates to only be updated over time, rather than updated more holistically to account for
11 any changes in the utility's actual costs of providing the service in a
12 particular time-period. As such, escalation rates are not necessarily representative of the
13 costs actually incurred to provide a service.

14 **Q: According to fundamental principles of cost-based ratemaking, how should CCA**
15 **Service Fees be determined?**

16 A: Typically, when a utility is updating service fees, basing these fees on an up-to-date cost
17 study is considered best practice.²⁰ A cost study is an analytical process that can be used to
18 determine how a utility's revenue requirement (or a portion thereof) should be assigned
19 across the different utility functions and customer classes based on cost causation. In this
20 particular context of setting CCA Service Fees, a reasonable cost study would identify the
21 incremental costs of providing billing services to CCA customers via an analysis of the
22 billing activities performed for both bundled and unbundled customers, the utility time and
23 resources to perform these activities, and the per-account incremental difference in service
24 between bundled and unbundled customers. CCA-specific service fees could then be set to
25 recover these incremental costs from CCA accounts.

¹⁸ National Association of Regulatory Utility Commissioners, "Escalation Factors: A Review of the Literature," pp. 14-15 (Jan. 2021), <https://pubs.naruc.org/pub.cfm?id=7BFEF211-155D-0A36-31AA-F629ECB940DC>.

¹⁹ Cal. Pub. Util. Code §§ 365.2, 366.3; D.23-04-040, Ordering Paragraph 1(c).

²⁰ James C. Bonbright, "Criteria of a Sound Rate Structure," 2nd ed., Criteria of a Sound Rate Structure (original 1961 text and revised 1988 edition), p. 383.

1 This approach is not only supported by the leading rate design literature; PG&E
2 itself admitted via discovery that CCA Service Fees should be based on cost-of-service
3 principles, and that up-to-date cost studies are the generally accepted method for
4 establishing costs of service for utility costs.²¹

5 **Q: Did PG&E conduct a cost study to inform its proposed increases to the CCA Service**
6 **Fees?**

7 A: No. PG&E represented in discovery that it has not tracked or calculated the actual costs
8 involved in providing the services associated with the Master Data Management Agent,
9 Rate-Ready Billing, or Bill-Ready Billing fees.²² Instead of tracking the actual costs
10 incurred, PG&E has taken the shortcut of relying on an escalator to adjust the currently
11 approved service fees. In response to discovery on this issue, PG&E justifies this shortcut
12 by referencing the fact that the currently approved fees were based on 2015 actual costs
13 and actual transactions processed.²³ PG&E reasons that, because these fees were cost-based
14 as of about ten years ago, applying a labor escalation factor to those fee levels is a sufficient
15 approximation of actual costs incurred.²⁴

16 **Q: Does CalCCA agree that applying a labor escalation factor to fees based on 2015**
17 **actual costs is a sufficient approximation of actual costs incurred?**

18 A: No. It is unreasonable for PG&E to rely on an escalator to update such a dated calculation.

19 **Q: Can you explain in more detail why it is unreasonable for PG&E to rely on an**
20 **escalator in this case given the underlying calculation is from 2015?**

21 A: Continuing to base the CCA Service Fees on 2015 actual costs and actual transactions
22 processed is unreasonable because this data is over ten years old. It therefore reflects costs
23 associated with serving a different unbundled customer set, with different systems and sets
24 of constraints. PG&E's unbundled customer base and the billing processes it uses to serve
25 these customers have evolved dramatically over the course of the past ten years. Notably,
26 in 2015, only around seven percent of PG&E's customers were unbundled.²⁵ By 2025,

²¹ Attachment KJC-2 (PG&E Response to CalCCA DR 7.01).

²² 6(. (PG&E Response to CalCCA DRs 1.24, 1.25, and 1.26).

²³ 6(. (PG&E Response to CalCCA DR 1.20).

²⁴ 6(. (PG&E Response to CalCCA DRs 1.24, 1.25, and 1.26).

²⁵ 6(. (PG&E Response to CalCCA DR 7.02).

1 . \$15B\$71*12%)' of PG&E's customers were unbundled and served by third-party
2 generation providers like CCAs.²⁶ PG&E's billing systems have had to evolve to
3 accommodate this substantial increase, and it is highly likely that there are economies of
4 scale in performing these billing services for this growing customer set.

5 PG&E has had multiple opportunities to update its cost data to make it more
6 relevant and representative of current costs. For example, PG&E could have updated this
7 cost data in its 2020 Phase II GRC, or in its testimony in this case. Instead, it has continued
8 to rely on 10-year-old data.

9 PG&E has stated its openness to reassessing whether doing a study of the
10 underlying costs incurred for service fees would be warranted in the next Phase II GRC.²⁷
11 While a cost study is needed in the next GRC, moving forward with increasing these fees
12 based on an escalator now is not an appropriate interim solution. This would result in 2015
13 costs, as increased by an arbitrary escalator (as discussed further below), dictating CCA
14 fees up until the Commission's approval and implementation of PG&E's Phase II
15 GRC application (likely through 2028). This is not a reasonable approach.

16 **Q: Can you explain in more detail why PG&E's choice of labor escalator is also**
17 **unreasonable?**

18 **A:** Even accepting the false premise that it is generally reasonable for PG&E to update these
19 fees via an escalation factor, PG&E's proposal is unreasonable because the particular labor
20 escalator PG&E proposes to use is inappropriate. PG&E proposes to use its total labor
21 escalator, which is a general escalator that is inapplicable to the subset of employees
22 engaged in performing the billing services covered by the CCA Service Fees.

23 More specifically, PG&E is proposing to use labor escalation rates that are within
24 the "Average Labor Escalation – All Employees" category filed as part of Exhibit (PG&E-
25 8) Human Resources in PG&E's 2023 GRC Phase I proceeding.²⁸ The proposed labor
26 escalation factor of 3.46 percent is a weighted average labor escalation rate for the
27 Administrative and General (A&G) and Operating group of employees.²⁹ However,

²⁶ 6(.
²⁷ 6(. (PG&E Response to CalCCA DR 1.29).
²⁸ Exh. PG&E-3 at 9-5:1-3.
²⁹ Attachment KJC-2 (PG&E Response to CalCCA DR 1.27).

1 excluding employees under a negotiated labor agreement and certain management
2 personnel, the average labor escalation rate for A&G and Operating employees is only
3 approximately 3 percent.³⁰

4 Using a weighted average labor escalation does not represent the actual costs
5 incurred by PG&E to perform these services given the subset of employees actually
6 performing these billing services. When asked to provide the titles of the employees that
7 perform the services covered by the CCA Service Fees, PG&E identified 12 different
8 roles.³¹ Of these 12 roles, only two of them are covered under a negotiated labor agreement;
9 the remaining ten roles are employees that are neither covered under a negotiated labor
10 agreement nor operating in management-level roles.³² As such, the proposed labor
11 escalation rate is not representative of the employee set providing these billing services and
12 it should not be applied to increase CCA Service Fees.

13 **Q: Can you explain in more detail your concern regarding PG&E’s overlapping Phase**
14 **I and Phase II GRC requests related to these billing services?**

15 **A:** In response to discovery in this case, PG&E represented that it has not calculated its actual
16 cost to provide the billing services covered by the CCA Service Fees to CCAs in any year
17 from 2021 through 2024.³³ It also represented that it does not track the labor time associated
18 with the services covered by these fees.³⁴ These responses suggest that PG&E does not
19 have information regarding the actual costs incurred to provide these services from 2021
20 through 2024.

21 PG&E also indicated in response to discovery in this case that it does not include
22 any revenue or cost offset in its Phase I GRCs for its CCA Service Fees.³⁵ This response
23 suggests that PG&E is not tracking and reconciling the revenues it receives from its CCA
24 Service Fees with any Phase I GRC billing service related revenue requirement that may
25 cover overlapping costs.

30 6(. (PG&E Response to CalCCA DR 1.27 and WP 4-21).
31 6(. (PG&E Response to CalCCA DRs 4.01, 4.02, and 4.03).
32 6(.
33 6(. (PG&E Response to CalCCA DRs 1.24, 1.25, and 1.26).
34 6(. (PG&E Response to CalCCA DR 2.14).
35 6(. (PG&E Response to CalCCA DR 2.05).

1 Despite these responses, in PG&E's pending 2027 Phase I GRC, PG&E provided
2 data showing that it (1) both forecasts and tracks the actual costs associated with the billing
3 services covered by the CCA Service Fees, and (2) has been over-collecting costs
4 associated with these services during the last GRC period, between 2020 and 2024.

5 **Q: Can you explain in more detail the information provided by PG&E in its 2027 Phase**
6 **I GRC regarding CCA Service Fee costs and revenues?**

7 A: In its 2027 Phase I GRC, PG&E confirmed in discovery that the costs associated with
8 providing billing services to CCAs are included as part of the Phase I GRC revenue
9 requirement, and that the billing services revenue requirement attributable to CCAs is
10 tracked and offset by the billing service fees collected from CCAs.³⁶ Based on data
11 provided by PG&E, from 2020 through 2024, the revenue from Direct Access (DA) and
12 CCA billing service fees received by PG&E was greater than the DA/CCA billing service
13 expenses by \$10.3 million.³⁷ To address this over-collection, in the 2027 Phase I GRC,
14 PG&E proposed a net credit allocated to the Gas and Electric Distribution functions.³⁸
15 Under this approach, the net credit, or the amount of overpayment by DA providers/CCAs,
16 would be allocated to bundled customers as well as to DA/CCA customers, resulting in a
17 subsidy to bundled customers paid for by unbundled customers.³⁹

18 This overcollection of CCA Service Fees identified in PG&E's 2027 Phase I GRC
19 has a clear implication for this Phase II GRC: it provides even more evidence that PG&E's
20 request in this case to increase the CCA Service Fees by 20 percent using a labor escalator
21 is not justified. PG&E's latest data shows that its current fee levels resulted in an
22 (712%##%\$) *of costs relative to actual expenses incurred; therefore, these fee levels
23 should actually be 21/ ; %4/ , if anything.

³⁶ Attachment KJC-3 (PG&E Response to CalCCA DRs 2.22 and 5.16 in A.25-05-009).

³⁷ 6(. (PG&E Response to CalCCA DR 5.16 in A.25-05-009). The attachment shows a net credit in most years, which is consistent with PG&E's stated practice of reducing costs by the revenue received, and therefore the sum of the total expense shown is equal to the net cost or net revenues from CCA Service Fees.

³⁸ !""%(. (PG&E Response to CalCCA DRs 2.22, 5.16, and 14.02 in A.25-05-009); A.25-05-009, Exh. PG&E-10 at 2-4:19-27. !""25\$+ A.25-05-009, ; -"02-" () 7%-"/8)9"\$8% , + '?'>3?2') 1 285"?)+')C"H25< +<)*25* *#, p. 78, lines 5-7 (Feb. 13, 2026) (CalCCA A.25-05-009 Testimony).

³⁹ CalCCA A.25-05-009 Testimony, p. 78, lines 7-10.

1 **Q: Can you explain in more detail the anticipated impact of PG&E’s BMI project on**
2 **these CCA Service Fees?**

3 A: In PG&E’s pending BMI application proceeding, PG&E has confirmed that its BMI project
4 is likely to further improve PG&E’s efficiency in providing these kinds of billing services
5 to CCAs going forward. Specifically, PG&E asserts that the transition to the new billing
6 system “is expected to drive efficiencies such as reducing manual interventions,
7 streamlining data exchanges, and improving billing.”⁴⁰ While PG&E maintains that “[i]t is
8 not possible at this time to quantify how these efficiencies may affect CCA service fees[,]”
9 it nonetheless acknowledges that, on balance, this change “will improve operational
10 efficiency in supporting CCA-related services . . . stem[ming] from increased automation,
11 data standardization, and streamlined workflows.”⁴¹

12 These admissions suggest that PG&E is likely to incur lower costs in the provision
13 of these services in the near future, post BMI implementation. Thus further increases to the
14 current fee levels based on an arbitrary escalator—rather than actual cost data—are
15 unjustified and do not reflect the likely trajectory of these costs going forward.

16 **Q: What are your recommendations regarding PG&E’s proposed CCA Service Fees?**

17 A: I recommend the Commission reject PG&E’s proposed CCA Service Fee increases in this
18 Application. PG&E has failed to support its requested increases to its CCA Service Fees
19 with actual cost data, and it instead has relied on an inapplicable labor escalator to
20 arbitrarily increase fees at a time when the latest actual cost data reflects that the current
21 fee levels are resulting in (712%##%\$). and when PG&E is investing in a substantial
22 billing system overhaul that will automate these services in the near future. I recommend
23 the Commission order PG&E to complete a cost study to support any future proposals to
24 change these fees.

25 Finally, I recommend the Commission order PG&E to ensure that going forward,
26 its process for tracking its CCA Service Fee revenues and refunding customers for any
27 overcollections does not result in any cost shifting between customers. Specifically, in this
28 case, the Commission should order PG&E to (1) cap its revenues associated with the CCA

⁴⁰ Attachment KJC-3 (PG&E Responses to PCE DRs 1.06, 1.07, 1.23, and 2.11 in A.24-10-014).

⁴¹ 6(. !"")25\$+ Attachment KJC-2 (PG&E Response to CalCCA DR 2.16).

1 Service Fees at the cost levels included in its forecast for these services provided in its 2027
2 Phase I GRC,⁴² and (2) track any revenue received above that cap and refund this amount
3 to unbundled customers via PG&E’s next ERRA compliance proceeding.⁴³

4 **B. PG&E’s Request to Propose Future Escalations to CCA Service Fees via the**
5 **Tier 2 Advice Letter Process is Unreasonable.**

6 **Q: What is PG&E proposing in this Application regarding the use of Tier 2 Advice**
7 **Letters to update its CCA Service Fees?**

8 A: PG&E is requesting that, going forward, the Commission allow it to propose any future
9 escalations to these CCA Service Fees via the Tier 2 Advice Letter process. This process
10 would replace PG&E’s current practice of proposing all such increases in its Phase II
11 GRCs.⁴⁴ PG&E states that this approach is preferable because it would allow more frequent
12 updates to these fees, instead of the status quo now, where PG&E must wait a minimum of
13 four years between GRCs to propose such updates for Commission review. PG&E intends
14 to use this Advice Letter process to update these fees every year based on the same labor
15 escalation assumptions used in this case.⁴⁵

16 **Q: What is the Commission’s Tier 2 Advice Letter process?**

17 A: In general, an Advice Letter is an informal request by a utility for Commission approval,
18 authorization, or other relief, including an informal request for approval to furnish service
19 under rates, charges, terms or conditions other than those currently contained in the utility’s
20 tariffs in effect.⁴⁶ A Tier 2 Advice Letter does not require Commission review; it is
21 effective after Staff approval. Appropriate uses of a Tier 2 Advice Letter include, for
22 example, “[a] change in a rate or charge pursuant to an index or formula that the
23 Commission has approved for use in an advice letter,” and “[a] tariff change that is
24 consistent with authority the Commission previously has granted to the Utility . . . such as
25 a rate change within a price floor and ceiling previously approved by the Commission.”⁴⁷

42 Attachment KJC-3 (PG&E Response to CalCCA DR 14.4 in A.25-05-009).

43 CalCCA A.25-05-009 Testimony, p. 79, lines 9-12.

44 Exh. PG&E-3 at 9-1:19-23.

45 Attachment KJC-2 (PG&E Response to CalCCA DRs 2.06 and 2.07).

46 General Order 96-B, General Rule 3.1.

47 General Order 96-B, Energy Industry Rule 5.2 (1) and (2).

1 **Q: What are your concerns with PG&E’s proposed Tier 2 Advice Letter process to**
2 **update these Service Fees?**

3 A: A Tier 2 Advice Letter process is not the appropriate venue for reviewing proposed changes
4 to the CCA Service Fees for several reasons.

5 First, as discussed above, the proposed increases to these fees in this Application
6 are not cost-based and are the result of the application of an arbitrary labor escalation factor
7 to 10-year-old data. Authorizing PG&E to continue to use this or a similar escalation
8 methodology to make future updates via the less formal Tier 2 Advice Letter process would
9 perpetuate and compound the issues with the unreasonable approach PG&E has advanced
10 in this case.

11 Second, the Tier 2 Advice Letter process should not be used to review significant
12 proposed cost increases to PG&E’s competitors. The Tier 2 Advice Letter process lacks
13 the formalities and process that should surround such reviews, and that accompany formal
14 Commission proceedings. For instance, Tier 2 Advice Letters do not require Commission
15 review and do not confer intervenors with discovery rights.

16 Third, the Tier 2 Advice Letter process does not offer intervenors or Staff a holistic
17 view of the utility’s costs like a formal GRC proceeding would. Instead, the process results
18 in single issue ratemaking. Single issue ratemaking generally should be avoided, as this
19 approach ignores offsetting changes in other revenues or costs, and generally reduces
20 transparency around the revenue requirement and ratesetting process.

21 Finally, PG&E’s request to utilize the Tier 2 Advice Letter process only
22 contemplates, and would only accommodate, service fee *§ 21 & 1*.⁴⁸ The Commission
23 should not accept PG&E’s unstated assumption here that the costs associated with
24 providing these services will only increase in the future. This premise is both contrary to
25 basic cost-of-service ratemaking principles, and, more practically, is unlikely to accurately
26 reflect the trajectory of PG&E’s actual costs in this area (as demonstrated by the
27 overcollection of CCA Service Fees between 2020 and 2024, discussed above). More
28 generally, it is highly unlikely that PG&E would incur the same amount of incremental
29 cost for these services with each customer added. That is because there are generally

⁴⁸ Attachment KJC-2 (PG&E Response to CalCCA DR 2.08).

1 economies of scale in meter reading and billing functions, so each new CCA customer
2 should result in lower marginal costs. Notably, PG&E has also confirmed in its pending
3 BMI proceeding that its proposed BMI project should improve PG&E's efficiency in
4 providing these kinds of billing services to CCAs going forward.⁴⁹ The Commission should
5 not allow PG&E to continue to arbitrarily escalate these fees through an informal
6 mechanism going forward, rather than track how these costs actually change under PG&E's
7 new billing system.⁵⁰

8 **Q: What do you propose regarding the process for PG&E's future updates to its CCA**
9 **Service Fees?**

10 A: The Commission should reject PG&E's proposal to update these fees via Tier 2 Advice
11 Letters in the future. In addition, the Commission should reiterate that PG&E is only
12 permitted to update these fees via a GRC application, and that any such update must be
13 supported by up-to-date information regarding PG&E's actual costs incurred in the
14 provision of these services.

15 **III. THE COMMISSION SHOULD ORDER PG&E TO UPDATE ITS PROVIDER OF**
16 **LAST RESORT FEE VIA SUPPLEMENTAL TESTIMONY IN THIS CASE AS**
17 **WELL AS UPDATED GRC TESTIMONY FOLLOWING THE**
18 **IMPLEMENTATION OF PG&E'S NEW BILLING SYSTEM.**

19 **Q: What is the Provider of Last Resort, or POLR, fee?**

20 A: The POLR re-entry fee and FSR are applicable to CCAs pursuant to Public Utilities Code
21 section 395.25(e).⁵¹ Re-entry fees include administrative costs and procurement costs
22 resulting from a mass involuntary return of CCA customers to utility service, and the FSRs
23 must cover those potential costs.⁵²

24 **Q: What is PG&E's proposal regarding POLR fees?**

25 A: PG&E is not proposing a change to the POLR fee in this Application. Instead, PG&E's
26 testimony merely describes the components and calculation of the POLR fee currently in
27 place.

⁴⁹ A.24-10-014, ; =B>.\$)C 1 6); -"02-"()9"\$8%, +'?, p. 4-45:10-22 (Oct. 23, 2024); Attachment KJC-3 (PG&E Responses to PCE DRs 1.06, 1.07, 1.23, and 2.11 in A.24-10-014).

⁵⁰ Attachment KJC-2 (PG&E Response to CalCCA DR 2.16).

⁵¹ Exh. PG&E-4:AppI-1:8-10.

⁵² 6(. at AppI-1:10-13.

1 **Q: What are the components of the current POLR fee?**

2 A: PG&E’s current POLR fee is \$4.24. It is based on four minutes of a Customer Service
3 Representative’s (CSR) time at \$57.89/hour. This represents the administrative cost to
4 process a customer’s request to return to bundled service, plus paper and postage for a
5 Customer Notification Letter (\$0.40).⁵³ The processing time covered by this fee includes
6 completion of the following tasks:⁵⁴

- 7 1. Notice to return to PG&E Bundled Service, PG&E Form 9-1011 (Notice), received and
8 processed by the Mail Room;
- 9 2. CSR verifies information on Notice is valid and complete;
- 10 3. If Notice is valid and complete, an electronic switching request is created in PG&E’s
11 Billing System;
- 12 4. If Notice is not valid and complete, call placed to customer to get needed information;
13 and
- 14 5. Electronic storage of customer notice.

15 **Q: When was the POLR fee adopted and when was it last updated?**

16 A: In Decision (D.) 18-05-022, the Commission established the POLR re-entry fees and FSR
17 applicable to CCAs. It ordered that, “[f]or purposes of calculating the [FSR] pursuant to
18 Public Utilities Code Section 394.25(e), the per-customer reentry fee for utility
19 administrative costs is to be based upon the reentry fee for voluntary returns in each utility’s
20 Schedule CCA–SF,” which at that time were \$4.24 for PG&E, \$1.12 for San Diego Gas &
21 Electric Company (SDG&E), and \$0.50 for Southern California Edison Company (SCE).⁵⁵

22 In D.24-04-009, the Commission revisited these fees and “continue[d] to find the
23 current proxy based on the IOU’s tariffed administrative re-entry fee to be reasonable.”⁵⁶
24 Despite this continued endorsement in D.24-04-009 of the general methodology of relying
25 on the “proxy” of the tariffed re-entry fee for voluntary returns, the Commission
26 nonetheless questioned the reasonableness of PG&E’s \$4.24 fee in that decision.
27 Addressing stakeholders’ concerns regarding the wide variation in the re-entry fees of the

⁵³ 6(. at AppI-1:25 to AppI-2:1.

⁵⁴ 6(. at AppI-2:3-11.

⁵⁵ D.18-05-022, Ordering Paragraph 2.

⁵⁶ D.24-04-009, p. 42.

1 different utilities, the Commission found that “it is concerning that PG&E’s per-customer
2 fee continues to be significantly higher than that of the other IOUs.”⁵⁷ However, the
3 Commission recognized that “since this variation in fees reflects differences in the billing
4 systems of each utility (including the level of automation), the most appropriate place to
5 address this issue is in each utility’s [GRC].”⁵⁸ The Commission found that PG&E should
6 propose any updates to its billing system to increase automation in a subsequent Phase I
7 GRC or in PG&E’s BMI application proceeding, and ordered PG&E to, “as part of [its]
8 next Phase 2 GRC . . . identify the administrative fee as a separate item, describe its
9 components, and explain how it is calculated.”⁵⁹

10 **Q: Why is PG&E not proposing any updates to this fee in this case?**

11 A: PG&E has not justified its failure to update this fee in this case. Instead, PG&E only
12 discusses the disclosure requirements from D.24-04-009 related to the POLR fee—that it
13 must identify the re-entry fee as a separate item, describe its components, and explain how
14 it was calculated.⁶⁰ PG&E also states it does not feel the need to update this fee because it
15 represents a “proxy” amount for switching CCA service back to PG&E bundled service on
16 a customer-by-customer basis, and in the event of an involuntary customer return event,
17 PG&E will be able to rely on the procedures outlined in Rule 23 to assess the actual cost
18 to charge the applicable CCA.⁶¹

19 **Q: Can you summarize your concerns with PG&E’s POLR fee?**

20 A: My concerns with PG&E’s POLR fee are that it (1) is based on dated inputs and
21 assumptions; (2) is not cost-based and does not reflect the methodology PG&E would
22 actually use to process a mass involuntary return; (3) is excessive when compared to the
23 analogous fees charged by the other IOUs; (4) is excessive when compared to similar
24 billing fees charged by PG&E itself; and (5) is likely to require a significant reduction in

⁵⁷ 6(.
⁵⁸ 6(.
⁵⁹ 6(. at 42-43.
⁶⁰ Exh. PG&E-4:AppI-1:14-16.
⁶¹ Attachment KJC-2 (PG&E Response to CalCCA DR 5.01).

1 the near future in light of the level of automation that will be achieved under PG&E’s new
2 post-BMI billing system.⁶²

3 **Q: Can you explain each of these concerns regarding PG&E’s POLR fee in more detail?**

4 A: First, PG&E proposes to continue to use 2015 labor and labor cost inputs to set this fee.⁶³
5 These inputs are unreasonably dated. The Commission should require PG&E to replace
6 these assumptions with ones that accurately reflect the current realities of PG&E’s
7 operations.

8 Second, PG&E admitted in discovery that a mass involuntary return to bundled
9 service would not actually cause PG&E to incur the costs reflected in the current POLR
10 fee.⁶⁴ In other words, PG&E has admitted that its POLR fee is not cost-based. This fee
11 assumes an impractical, manual process that is not representative of how PG&E would
12 actually handle a mass involuntary return.⁶⁵ Relying on this proxy cost—the cost of
13 manually processing each individual customer’s return to bundled service—to approximate
14 the cost of bulk processing of a mass involuntary return to bundled service is unreasonable
15 and not reflective of the efficiency gains achieved through economies of scale.

16 Third, PG&E’s POLR fee is exponentially higher than the corresponding fees
17 charged by SCE and SDG&E (approximately \$0.50 per customer service account for each
18 of the other two IOUs).⁶⁶ The Commission has found this discrepancy “concerning” and
19 directed PG&E to address it in its GRCs.⁶⁷

20 Fourth, PG&E’s POLR fee is even out of step with its (C) fees associated with
21 very similar services. For instance, PG&E’s fee for processing customer requests for opting
22 out of the CCA program is \$0.49 per account for an internet opt-out and \$0.42 per account

⁶² 6(.

⁶³ 6(. (PG&E Response to CalCCA DR 5.01(b)). !""25\$+)PG&E Advice Letter 5359-E; Attachment KJC-3 (PG&E Response to Joint CCA DR 14.3 in A.21-06-021).

⁶⁴ Attachment KJC-2 (PG&E Response to CalCCA DR 2.11).

⁶⁵ 6(. (conceding that “PG&E does not maintain that it will take 3,333 hours to process the involuntary return of 50,000 customers to PG&E’s bundled services.”).

⁶⁶ D.24-04-009, p. 41.

⁶⁷ 6(. at 42.

1 for an automated telephone opt-out, and its fee for processing the enrollment of a new
2 account onto CCA service after mass enrollment has occurred is \$0.49 per account.⁶⁸

3 Fifth, PG&E has admitted that the service covered by this fee is likely to be further
4 automated under PG&E’s new post-BMI billing system. PG&E has acknowledged that its
5 BMI “could potentially impact the costs associated with, and recovered through, PG&E’s
6 [POLR] fee[,]” as “[t]he initiative includes implementation of a new billing and customer
7 system designed to automate manual processes, enhance data management, and streamline
8 interactions with third-party providers[,]” and “[t]hese improvements may lead to
9 administrative cost reductions, including those related to POLR services.”⁶⁹ Specifically,
10 PG&E noted that the development of the Market Transaction Management (MTM) Module
11 within its BMI project:

12 [W]ill enable customers to seamlessly transition to bundled services if a
13 third-party provider voluntarily or involuntarily leaves the market,
14 minimizing service disruptions and maintaining reliable customers
15 experiences. MTM introduces functionality that is expected to allow PG&E
16 to return an entire CCA population to bundled service next day with
17 minimal impacts on billing and the customer experience.⁷⁰

18 If the BMI will automate a customer’s transition from unbundled to bundled service in this
19 manner, this means that the POLR fee should be substantially reduced or eliminated in the
20 near future. PG&E should therefore be required to review these costs again shortly after
21 implementation of the BMI so that it can pass along its anticipated savings—if they in fact
22 materialize—to customers.

23 **Q: What is your recommendation regarding the POLR fee?**

24 **A:** I recommend that the Commission direct PG&E to update its POLR fee for CCA customers
25 by: (1) ordering PG&E to submit supplemental testimony in this proceeding regarding its
26 actual method and costs to process a mass involuntary return of customers to bundled
27 service in 2026, using up-to-date data that reflects the economies of scale that would be
28 achieved in a mass return; (2) allowing intervenors the opportunity to submit rebuttal
29 testimony responsive to PG&E’s supplemental testimony on this topic in this proceeding,

⁶⁸ PG&E Electric Schedule E-CCA, Sheets 2-3, 2A2%52E5")28
https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDULES_E-CCA.pdf

⁶⁹ Attachment KJC-2 (PG&E Response to CalCCA DRs 2.10 and 2.09).

⁷⁰ A.24-10-014, ; = B>.\$)C 1 6); -"02-" ()9"\$% , + '?, p. 4-45 (Oct. 23, 2024).

1 and scheduling evidentiary hearings on this issue; and (3) ordering PG&E to submit
2 testimony in its next GRC application immediately following the implementation of its
3 BMI project regarding its actual method and costs to process a mass involuntary return of
4 customers to bundled service using PG&E's new billing system, using up-to-date data that
5 reflects the economies of scale that would be achieved in a mass return.

6 **Q: Does this conclude your testimony?**

7 **A: Yes.**

Attachment KJC-1
CV of Kyra J. Coyle



KYRA J. COYLE

Principal

CONTACT

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EDUCATION

Bachelor of Arts, Business
Administration with emphasis in
Accounting, Dakota Wesleyan
University

Minor, Computer Applications, Dakota
Wesleyan University

KEY EXPERTISE

Accounting
Budgeting
Contract Negotiations
Financial Modeling
Forecasting
Project Management
Regulatory Affairs
Strategic Planning

Ms. Kyra Coyle has over 20 years of experience in the utility, mining, and public accounting sectors and joined NewGen as a Senior Manager in December 2023 and has been promoted to a Principal as of January 2025. Her expertise includes utility revenue requirement analyses, strategic planning, project management, contract negotiations, financial modeling, regulatory affairs, budgeting, forecasting, and regulatory accounting. Her rate-related projects have included studies to develop retail electric, natural gas, transmission, ancillary service, standby and special contract rates.

Ms. Coyle has provided expert witness testimony on revenue requirement cost of service issues before public utility commissions and the Federal Energy Regulatory Commission. She has also offered other types of cost of service and rate-related litigation support.

PRIOR RELEVANT EXPERIENCE

Black Hills Corporation

Director of Regulatory/Finance – Wyoming, Montana and South Dakota Electric and Natural Gas Utilities

- Provide strategic leadership for all financial and regulatory matters for electric and natural gas utilities.
- Direct the development and filing of rate case applications and other regulatory filings supporting the Company's strategic plan, including new and innovative tariff offerings to incentivize economic development.
- Financial leader executing strategy for long-term success, responsible for \$1.9 billion of rate base. Received approval for a large transmission project (~260 miles).
- Contract negotiations with large, high density, power customers, including cost allocations for generation and transmission.
- Direct, develop, and maintain trusted relationships with regulatory, legislative, and other stakeholders.
- Expert witness for policy and financial matters to regulatory and legislative agencies.

Senior Manager of Finance and Regulatory Electric/Natural Gas Utilities

- Responsible for all forecasting and strategic planning aspects for Gas and Electric utilities and Non-Regulated companies, which requires positive working relationships with cross-functional teams.
- Part of the state-level executive leadership team; participate in operational initiatives – capital deployment, personnel plans, long-term strategic plans, and culture changes.
- Financial leader executing strategy for long-term success.
- Strong partnerships with operations and other matrix teams to execute key strategies.
- Financial modeling of purchase power agreements and strategic capital projects.
- Financial team member in the divestiture of 49.9% interest in a non-regulated entity.
- Lead, develop, and mentor coworkers.

KYRA J. COYLE

Principal

Professional Finance Senior/Principal

- Responsible for budgeting, forecasting, and reporting for power generation assets. This included developing innovative ways to earn on PPAs and maximizing value by working with the operations team to maintain availability and reliability.
- Budget, forecast, and report on capital and O&M spending over \$50M annually.
- The key contact person for generation operations staff; helped educate the operations team on the optimal timing of associated expenditures and investments.
- Monitor and report to third-party owners on capital and O&M.

U.S Bentonite Processing, Inc.

Accounting Manager

- Led and supervised the accounting support staff, delegating duties and reviewing and approving invoices, payments, and other activities. Completed performance reviews and co-supervising the purchasing and logistics roles.
- Prepare and distribute financial statements to the board of directors monthly.
- Responsible for closing, consolidation, and budgeting of three U.S.-based companies.
- As the first point of contact during the annual audit, Ms. Coyle provided all the data needed and any adjustments made after the closing of the last period of the fiscal year.
- Business SME for NetSuite. Responsible for creating a new chart of accounts, departments, and locations for three companies, training all software users, and answering questions.

Record of Testimony: Kyra J. Coyle

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
1. El Paso Electric Company	SOAH Docket No. 473-26-08223 PUC Docket No. 59137	Application of El Paso Electric Company for Approval of a System Resiliency Plan	Public Utility Commission of Texas	Office of Public Utility Counsel	2026
2. Texas-New Mexico Power Company	SOAH Docket No. 473-26-05799 PUC Docket No. 58964	Application of Texas-New Mexico Power Company for Authority to Change Rates	Public Utility Commission of Texas	Office of Public Utility Counsel	2026
3. Railbelt Transmission Organization	Docket No. U-25-028	In the Matter of the Initial Nondiscriminatory Open Access Transmission Tariff Designated as TA1-8001 Filed by the Railbelt Transmission Organization	The Regulatory Commission of Alaska	Homer Electric Association, Inc.	2025
4. Texas Gas Service Company, a Division of ONE Gas, Inc.	OS-25-00028202	Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc. to Change Gas Utility Rates Within the Unincorporated Areas of the Central-Gulf, West North, and Rio Grande Valley Service Areas	Railroad Commission of Texas	Cities Served by Texas Gas Service Company	2025
5. Pacific Gas and Electric Company	Docket No. A.24-10-014	Application of Pacific Gas and Electric Company for Approval of Its Billing Modernization Initiative	California Public Utilities Commission	Joint Community Choice Aggregators	2025
6. CenterPoint Energy Houston Electric, LLC	SOAH Docket No. 473-25-18704 PUC Docket No. 58028	Application of CenterPoint Energy Houston Electric, LLC for Determination of System Restoration Costs	Public Utility Commission of Texas	Office of Public Utility Counsel	2025
7. El Paso Electric Company	SOAH Docket No. 473-25-11219 PUC Docket No. 57568	Application of El Paso Electric Company for Authority to Change Rates	Public Utility Commission of Texas	Office of Public Utility Counsel	2025
8. Southwestern Electric Power Company	SOAH Docket No. 473-24-22136 PUC Docket No. 56643	Application of Southwestern Electric Power Company for Authority to Reconcile Fuel Costs	Public Utility Commission of Texas	Office of Public Utility Counsel	2025

Record of Testimony: Kyra J. Coyle

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
9. CenterPoint Energy Houston Electric, LLC	SOAH Docket No. 473-25-05323 PUC Docket No. 57271	Application of CenterPoint Energy Houston Electric, LLC for Determination of System Restoration Costs	Public Utility Commission of Texas	Office of Public Utility Counsel	2025
10. PacifiCorp	Docket No. 24-035-04	Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations	Public Service Commission of Utah	Stadion, LLC	2024
11. PacifiCorp	Docket No. UE 433	PacifiCorp d/b/a Pacific Power Request for General Rate Revision	Public Utility Commission of Oregon	Vitesse, LLC	2024
12. CenterPoint Energy Houston Electric, LLC	SOAH Docket No. 473-24-13232 PUC Docket No. 56211	Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates	Public Utility Commission of Texas	Office of Public Utility Counsel	2024
13. Constellation Mystic Power, LLC.	Docket No. ER18-1639-027	Annual Fixed Revenue Requirement, Capital Expense Recovery, and Stipulated Variable Cost Recovery for Mystic 8 & 9 Fuel Security System	Federal Energy Regulatory Commission	Eastern New England Consumer-Owned Systems (ENECOS)	2024
14. Peoples Gas Light and Coke Company	Docket No. 23-0069	Proposed General Increase in Gas Rates and Revisions to Other Terms and Conditions of Service	Illinois Commerce Commission	City of Chicago	2024
15. Southern Indiana Gas and Electric Company DBA CenterPoint Energy Indiana South	Cause No. 45990	Authority to Modify its Rates and Charges for Electric Utility Service Through a Phase-In of Rates...	Indiana Utility Regulatory Commission	SABIC Innovative Plastics Mount Vernon, LLC	2024

Record of Testimony: Kyra J. Coyle

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
16. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-228-EN-23	Certificate of Public Convenience and Necessity to Construct and Operate a New 115 kV Substation, Two New 115 kV Transmission Lines, Modification and Extension of Four 115 kV Transmission Lines, Four New 115 kV Load-Serving Transmission Lines and Related Facilities	Wyoming Public Service Commission	--	2023
17. Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20002-131-EA-23	Proposed Modification of the Neil Simpson II Generation Facility to a Dual Fuel Source and Request for a Determination Regarding the Need to File for a Certificate of Public Convenience and Necessity	Wyoming Public Service Commission	--	2023
18. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-225-EM-23	Authority to Increase Its Power Cost Adjustment by \$0.00872 per Kilowatt Hour	Wyoming Public Service Commission	--	2023
19. Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20003-223-ET-23	Authority to Establish a Low-Carbon Surcharge Tariff and Rate	Wyoming Public Service Commission	--	2023
20. Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20002-127-ET-23	Authority to Establish a Low-Carbon Surcharge Tariff and Rate	Wyoming Public Service Commission	--	2023
21. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-221-EA-23	Establish Intermediate Low-Carbon Portfolio Standards and Requirements	Wyoming Public Service Commission	--	2023
22. Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20002-126-EA-23	Establish Intermediate Low-Carbon Portfolio Standards and Requirements	Wyoming Public Service Commission	--	2023

Record of Testimony: Kyra J. Coyle

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
23. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-217-EM-23	Authority to Decrease Its Power Cost Adjustment by \$0.03149 per Kilowatt-Hour	Wyoming Public Service Commission	--	2023
24. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-78-GR-23	Authority to Implement a General Rate Increase of \$19,262,412 per Annum and Extend Its Wyoming Integrity Rider	Wyoming Public Service Commission	--	2023
25. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-214-ER-22	A General Rate Increase of \$15,366,026 per Annum and Authority to Revise Its Power Cost Adjustment Mechanism	Wyoming Public Service Commission	--	2022
26. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-213-EM-22	Authority to Increase Its Power Cost Adjustment by \$0.00129 per Kilowatt-Hour	Wyoming Public Service Commission	--	2022
27. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-211-EM-22	Authority to Pass on a Blockchain Interruptible Service Customer Credit Adjustment Rate of \$0.00 per Kilowatt-Hour Effective June 1, 2022	Wyoming Public Service Commission	--	2022
28. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-210-ET-22	Revise the Demand Side Management Surcharge Rate, Effective June 1, 2022	Wyoming Public Service Commission	--	2022
29. Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20003-209-EA-22	Establish Intermediate Low-Carbon Energy Portfolio Standards and Requirements	Wyoming Public Service Commission	--	2022
30. Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20002-123-EA-22	Establish Intermediate Low-Carbon Energy Portfolio Standards and Requirements	Wyoming Public Service Commission	--	2022

Record of Testimony: Kyra J. Coyle

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
31. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-208-EA-22	Authority to Increase Its Voluntary Renewable Energy Rider Rate to \$0.47 per Month per 100-KWh Block, Effective April 1, 2022	Wyoming Public Service Commission	--	2022
32. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-206-EN-22	A Certificate of Public Convenience and Necessity to Construct and Operate One New 230 kV Substation, Two Replacement 115 kV Substations, Three 230 kV Transmission Lines, Two 115 kV Transmission Lines and Related Facilities in Converse, Laramie, Goshen and Platte Counties on Wyoming and Scotts Bluff County in Nebraska	Wyoming Public Service Commission	--	2022
33. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-68-GM-22	Authority to Implement Wyoming Integrity Rider Rates of \$0.0231 per Therm for Residential General Service, \$0.0139 per Therm for Small General Service, \$0.0148 per Therm for Medium General Service, \$0.0092 per Therm for Large General Service, and \$0.0285 per Therm for On-System Transportation Service	Wyoming Public Service Commission	--	2022
34. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-67-GM-22	Authority to Decrease the Revenue Adjustment Mechanism Rate By \$0.0058 per Therm	Wyoming Public Service Commission	--	2022
35. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-66-GP-22	Authority to Pass on a Gas Cost Rate Decrease of \$0.1155 per Therm	Wyoming Public Service Commission	--	2022

Record of Testimony: Kyra J. Coyle

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
36. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-65-GN-22	Determination of CPCN Requirements Regarding the Relocation of an Existing Transmission Pipeline and Related Facilities	Wyoming Public Service Commission	--	2022
37. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-63-GP-22	Authority to Pass on a Gas Cost Rate Decrease of \$0.0026 per Therm	Wyoming Public Service Commission	--	2022
38. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-60-GM-22	Authority to Increase the Revenue Adjustment Mechanism Rate by \$0.0022 Per Therm	Wyoming Public Service Commission	--	2022
39. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-57-GT-22	Authority to Decrease the Energy Efficiency Surcharge for Residential Customers by \$0.0034 per Therm and Increase It by \$0.0006 per Therm for Non-Residential Customers	Wyoming Public Service Commission	--	2022
40. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-55-GP-22	Authority to Pass on a Wholesale Gas Cost Increase of \$0.0669 per Therm	Wyoming Public Service Commission	--	2022
41. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-205-ET-21	Approval of the 2022-2024 Demand Side Management Program Plan by November 1, 2021, for Implementation on January 1, 2022	Wyoming Public Service Commission	--	2021
42. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-203-EM-21	Authority to Pass on a Blockchain Interruptible Service Customer Credit Adjustment Rate Of \$0.00 Per KWh Effective June 1, 2021	Wyoming Public Service Commission	--	2021
43. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-202-EM-21	Authority to Increase Its Power Cost Adjustment by \$0.00246 per Kilowatt-Hour	Wyoming Public Service Commission	--	2021

Record of Testimony: Kyra J. Coyle

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
44. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-201-EN-21	Certificate of Public Convenience and Necessity to Construct and Operate Two 115 kV Substations, Associated Transmission Lines, and Related Facilities in Laramie County, Wyoming	Wyoming Public Service Commission	--	2021
45. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-200-ET-21	Authority to Update Its Demand Side Management Surcharge Rate, Effective June 1, 2021	Wyoming Public Service Commission	--	2021
46. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-199-EA-21	Authority to Increase Its Voluntary Renewable Energy Rider Rate to \$0.43 per Month per 100-KWh Block, Effective April 1, 2021	Wyoming Public Service Commission	--	2021
47. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-198-EN-21	Certificate of Public Convenience and Necessity to Construct and Operate a 115 kV Substation, Associated Transmission Lines, and Related Facilities in Laramie County, Wyoming	Wyoming Public Service Commission	--	2021
48. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-194-EM-20	Authority to Increase Its Power Cost Adjustment by \$0.00243 per Kilowatt-Hour Effective July 1, 2020	Wyoming Public Service Commission	--	2020
49. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-193-EN-20	Certificate of Public Convenience and Necessity to Rebuild an Existing 115 kV Transmission Line from Skyline Substation to East Business Park Substation in Laramie County, Wyoming	Wyoming Public Service Commission	--	2020
50. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-190-ET-20	Authority to Update Its Tariff Applicable to the Demand Side Management Margin Revenue Recovery, the Balancing Account and Program Costs	Wyoming Public Service Commission	--	2020

Record of Testimony: **Kyra J. Coyle**

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
51. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-188-ET-20	Authority to Decrease Its Electric Voluntary Renewable Energy Rider Rate to \$0.03 per Month per 100-KWh Block	Wyoming Public Service Commission	--	2020
52. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-182-ET-19	Authority to Update Its Electric and Gas Tariffs Applicable to the Demand Side Management Margin Revenue Recovery, the Balancing Account and Program Costs	Wyoming Public Service Commission	--	2019
53. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-173-ET-18	Authority to Implement a Blockchain Interruptible Service Tariff	Wyoming Public Service Commission	--	2018

Attachment KJC-2
PG&E Responses to CalCCA Discovery Requests

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_001-Q020
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_001-Q020
Request Date:	January 24, 2025
Requester DR No.:	001
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	February 6, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

QUESTION 020

Referring to Testimony PG&E-3 page 9-3: Please provide workpapers in electronic format from PG&E’s 2017 GRC II proceeding demonstrating how PG&E calculated the approved fees for Meter Data Management Agent (\$0.14), Rate-Ready Billing (\$0.21), and Bill-Ready Billing (\$0.21) services to ESPs.

ANSWER 020

Please see the attached, “*GRC-2023-PhII_DR_CalCCA_001-Q020Atch01.pdf*,” that provides the PG&E’s 2017 GRC II workpaper that provides how PG&E calculated its approved fees.

Support Workpaper for 2017 GRC Phase II Exhibit II Appendix C

Source Data
(2015 # of actual transactions processed per ABS system report)

	DA		CCA	
	Rate-Ready	Bill-Ready	Rate-Ready	Bill-Ready
2015				
Jan	2,534	56	0	284,133
Feb	2,515	55	0	282,958
Mar	2,499	55	0	293,111
Apr	2,487	54	0	291,895
May	2,471	54	0	291,445
Jun	2,450	54	0	321,157
Jul	2,443	54	0	363,092
Aug	2,425	52	0	362,924
Sep	2,403	52	0	362,711
Oct	2,373	53	0	362,865
Nov	2,364	53	0	363,113
Dec	2,347	59	0	363,477
Total	29,311	651	0	3,942,881

Proposed Fee Calculation for DA/CCA Billing and MDMA Services
(↖ = proposed per bill/service fee)

	DA/CCA	MDMA
↖ 2015 units	3,972,843	3,972,843
↘ 2015 Costs	\$ 840,915	\$ 576,043
↗ Cost per Bill	\$ 0.21	\$ 0.14

↖ 2015 Costs = reported on 2015 Annual Report to CPUC

Sum = Total 2015 Units: 3,972,843 ↗

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_001-Q024
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_001-Q024
Request Date:	January 24, 2025
Requester DR No.:	001
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	February 12, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

QUESTION 024

Referring to Testimony PG&E-3 page 9-3: Has PG&E calculated the actual cost to provide Meter Data Management Agent services to ESPs in any year from 2021 through 2024? If yes, please provide all workpapers quantifying such costs in total dollars and dollars per meter per month. If no, please explain why not.

ANSWER 024

No, PG&E did not calculate the actual cost to provide Meter Data Management Agent services to ESPs for any year from 2021 through 2024, including quantifying the number of meters or accounts served. PG&E's 2023 GRC Phase II testimony proposal is limited to applying labor escalation factors to update the existing fee for this service, approved as part of our 2017 GRC Phase II proceeding, which was based on labor costs as of that time. Thus we believe it is reasonable to apply labor escalation factors to update the adopted fee at this time. Please see PG&E's response to GRC-2023-PhII_DR_CalCCA_001-Q027 for workpapers in support of the escalation factors used.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response

PG&E Data Request No.:	CalCCA_001-Q025
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_001-Q025
Request Date:	January 24, 2025
Requester DR No.:	001
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	February 12, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

QUESTION 025

Referring to Testimony PG&E-3 page 9-3: Has PG&E calculated the actual cost to provide Rate-Ready Billing services to ESPs in any year from 2021 through 2024? If yes, please provide all workpapers quantifying such costs in total dollars and dollars per meter per month. If no, please explain why not.

ANSWER 025

No, similar to our response to CalCCA_001-024, PG&E did not calculate the actual cost to provide Rate-Ready Billing services to ESPs in any year from 2021 through 2024, including quantifying the number of meters or accounts served because our 2023 GRC Phase II testimony proposal is limited to applying labor escalation factors to the existing adopted fee. Please see PG&E's response to GRC-2023-PhII_DR_CalCCA_001-Q027 for workpapers in support of the escalation factors used.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_001-Q026
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_001-Q026
Request Date:	January 24, 2025
Requester DR No.:	001
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	February 12, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

QUESTION 026

Referring to Testimony PG&E-3 page 9-3: Has PG&E calculated the actual cost to provide Bill-Ready Billing services to ESPs in any year from 2021 through 2024? If yes, please provide all workpapers quantifying such costs in total dollars and dollars per meter per month. If no, please explain why not.

ANSWER 026

No, similar to our responses to CalCCA_001-024 and 001-025, PG&E did not calculate the actual cost to provide Bill-Ready Billing services to ESPs in any year from 2021 through 2024, including quantifying the number of meters or accounts served because our 2023 GRC Phase II testimony proposal is limited to applying labor escalation factors to the existing adopted fee. Please see also PG&E's response to GRC-2023-PhII_DR_CalCCA_001-Q027 for workpapers in support of the escalation factors used.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_001-Q027
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_001-Q027
Request Date:	January 24, 2025
Requester DR No.:	001
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	February 6, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

QUESTION 027

Referring to Testimony PG&E-3 Table 9-4: Please provide electronic workpapers supporting the referenced exhibit from the 2023 GRC (Exhibit (PG&E-8), Chapter 4, Section G, p.4-22, Table 4-2 “2021-2026 Wage Increases”).

ANSWER 027

Please see “*GRC-2023-PhII_DR_CalCCA_001-Q027Atch01.pdf*” for the workpapers used to support 2023 GRC, Exhibit (PG&E-8), Chapter 4, Section G, p. 4-22, Table 4-2 “2021-2026 Wage Increases.”

(PG&E-8)

PACIFIC GAS AND ELECTRIC COMPANY
2023 GENERAL RATE CASE
EXHIBIT (PG&E-8) HUMAN RESOURCES

WORKPAPERS SUPPORTING
CHAPTER 4, COMPENSATION: STIP, NON-QUALIFIED RETIREMENT AND LABOR
ESCALATION

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2021 STIP Scorecard	WP 4-8
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Historical and Forecast Expenses	WP 4-18
Historical Adjustments	WP 4-19
Historical and Forecast Year over Year Walk	WP 4-20
Forecast Methodology	WP 4-21
<u>Labor Escalation</u>	
Methodology to Calculate Weighted Labor Escalation	WP 4-22
World at Work Salary Budget Survey Report	WP 4-24
<u>Rewards and Recognition</u>	WP 4-29
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World at Work Trends in Employee Recognition	WP 4-30

Pacific Gas and Electric Company
2020 General Rate Case
Exhibit (PG&E-8) Human Resources

Methodology to Calculated Weighted Labor Escalation

1. Each utility employee as of March 31, 2020 was categorized based on their organization: A&G or Operating
2. Each utility employee as of March 31, 2020 was also categorized as either represented (bargaining unit) or non-bargaining unit
3. Based on work locations, employees with locations in the following counties were assigned a San Francisco Bay Area designation. All others were assigned a non-San Francisco Bay Area designation.

Alameda
Contra Costa
Marin
Monterey
Napa
Sacramento
San Francisco
San Mateo
Santa Clara
Santa Cruz
Solano
Sonoma

4. The percentage increase based on the table below was applied to the March 31, 2020 annual salary and the new salary calculated for each person.

Group	Escalation Rate		Basis
	2021	2022 - 2026	
IBEW' Represented Employees*	3.00%	3.75%	Negotiated Labor Agreements
ESC Represented Employees*	3.00%	3.75%	Negotiated Labor Agreements
SEIU Represented Employees*	3.00%	3.00%	Negotiated Labor Agreements
Non-Represented Admin and Technical Bay Area	3.00%	3.00%	Market Data
Non-Represented Admin and Technical Non - Bay Area	3.00%	3.00%	Market Data
Management Bay Area	3.10%	3.10%	Market Data
Management Non-Bay Area	3.00%	3.00%	Market Data

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_001-Q029
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_001-Q029
Request Date:	January 24, 2025
Requester DR No.:	001
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	February 12, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

QUESTION 029

Referring to Testimony PG&E-3 Table 9-1: Please explain if PG&E proposes to limit the scope of updates to the identified ESP service fees when made through Tier 2 Advice Letters, for example to only update the fee by applying escalation factors rather than re-evaluating the underlying costs incurred to provide the service.

ANSWER 029

Yes, PG&E proposes to limit the scope of updates to the identified ESP service fees when made through Tier 2 Advice Letters to only update the fees by applying escalation factors. In future GRC Phase II proceedings, we are open to reassessing whether doing a study of the underlying costs incurred for providing EPS services would be warranted.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_002-Q005
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_002-Q005
Request Date:	April 15, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	April 29, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: CALCCA’S SECOND DATA REQUEST TO PG&E

QUESTION 005

Referencing PG&E’s responses to CalCCA requests 1.28 and 1.29: Please provide the total amount of revenue or cost offset included in PG&E’s most recent Phase I GRC revenue requirement for each of the following actual or estimated ESP service fees:

- a. Meter Data Management Agent
- b. Rate-Ready Billing
- c. Bill-Ready Billing

ANSWER 005

The requested information was not included in PG&E’s 2023 GRC Phase I filing, which is PG&E’s most recent Phase I GRC filing.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_002-Q006
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_002-Q006
Request Date:	April 15, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	April 29, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: CALCCA’S SECOND DATA REQUEST TO PG&E

QUESTION 006

Referencing PG&E’s responses to CalCCA requests 1.28 and 1.29: Please provide the proposed escalation assumptions PG&E proposes to rely on for the Tier 2 Advice Letter updates for ESP service fees.

ANSWER 006

PG&E proposes to rely on the escalation assumptions consistent with those provided in “GRC-2023-PhII_DR_CalCCA_002-Q004Atch01.xlsx” to support the Tier 2 Advice Letter updates to ESP service fees.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_002-Q007
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_002-Q007
Request Date:	April 15, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	April 22, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: CALCCA’S SECOND DATA REQUEST TO PG&E

QUESTION 007

Referencing PG&E’s responses to CalCCA requests 1.28 and 1.29: Please clarify if PG&E is proposing to complete the Tier 2 Advice Letter process for ESP service fees every year? If so, when in the year is PG&E proposing to file the Tier 2 Advice Letter for changes to ESP service fees? If not, what criteria will PG&E use to determine the appropriate timing for filing a Tier 2 Advice Letter to update ESP service fees?

ANSWER 007

Yes, PG&E proposes to use the Tier 2 Advice Letter (AL) process to update the ESP service fees every year. PG&E proposes to file the Tier 2 AL near the start of the 4th quarter (October through December) each year but no sooner than twelve months after the last fee update approved by the CPUC.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_002-Q008
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_002-Q008
Request Date:	April 15, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	April 29, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: CALCCA’S SECOND DATA REQUEST TO PG&E

QUESTION 008

Referencing PG&E’s response to CalCCA requests 1.28 and 1.29: If the escalation factor results in a reduction to ESP service fees, would PG&E still file a Tier 2 Advice Letter to update ESP service fees?

ANSWER 008

Based on the labor escalation assumptions PG&E will be relying on for fee escalation updates, a reduction based on escalation factor is not expected. If escalation assumptions used to determine an escalation factor results in a fee increase of less than one cent (US) per any given 12-month cycle, a Tier 2 Advice Letter (AL) will not be filed to update that fee for that 12-month period. However, that unused factor will be added to the next 12-month cycle escalation factor to determine if the fee escalation results to an increase of one cent or more that would necessitate a Tier 2 AL catch-up filing for that period.

Also see the labor escalation assumptions referenced above in PG&E’s response to CalCCA_002_Q004.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_002-Q009
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_002-Q009
Request Date:	April 15, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	April 29, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: CALCCA’S SECOND DATA REQUEST TO PG&E

QUESTION 009

Referencing PG&E’s response to CalCCA request 1.30: Please explain PG&E’s plan to automate this process to bring the POLR fee down, in line with the rates in effect for the other two electric IOUs in California. If PG&E has no plan to automate this process, please explain why not.

ANSWER 009

PG&E’s plan to reduce the administrative cost of Provider of Last Resort (POLR) services is included as part of its Billing Modernization Initiative. While there is no separate automation plan specific to POLR, the new billing platform being implemented under the Billing Modernization Initiative is expected to support more efficient and streamlined POLR-related processes. These improvements may help lower costs over time. Any potential fee adjustments will depend on realized efficiencies and be subject to regulatory review.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_002-Q010
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_002-Q010
Request Date:	April 15, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	April 29, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: CALCCA’S SECOND DATA REQUEST TO PG&E

QUESTION 010

Referencing PG&E’s response to CalCCA request 1.30:

- a. Please explain if PG&E’s Billing Modernization Initiative is likely to, or could possibly, impact the costs associated with and recovered via PG&E’s POLR fee?
- b. If the answer to part (a) is in the affirmative, is PG&E planning to pass along any associated cost savings to customers? If so, please detail any and all such plans.

ANSWER 010

- a. Yes, PG&E’s Billing Modernization Initiative (BMI) could potentially impact the costs associated with, and recovered through, PG&E’s Provider of Last Resort (POLR) fee. The initiative includes implementation of a new billing and customer system designed to automate manual processes, enhance data management, and streamline interactions with third-party providers. These improvements may lead to administrative cost reductions, including those related to POLR services.
- b. If cost savings associated with POLR services are realized because of the BMI, PG&E would expect to reflect those changes in future cost recovery filings, subject to regulatory review. However, at this time, PG&E does not have a specific or separate plan to pass along POLR-related cost savings to customers, as these potential savings have not yet been realized or quantified. Once the system is fully implemented and stabilized, any reductions in POLR-related costs would be evaluated through the applicable regulatory process, and PG&E would follow standard procedures to adjust the POLR fee, if appropriate.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response

PG&E Data Request No.:	CalCCA_002-Q011
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_002-Q011
Request Date:	April 15, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	April 29, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: CALCCA’S SECOND DATA REQUEST TO PG&E

QUESTION 011

Referencing PG&E’s response to CalCCA request 1.30: If 50,000 customers were to return to bundled service of PG&E, does PG&E maintain that it will take 3,333 hours (50,000 customers x 4 minutes / 60 minutes) to process this return to bundled services? Please explain.

ANSWER 011

For purposes of responding to this question, PG&E interprets that the 50,000 customers would be returning to bundled service involuntarily.

No, PG&E does not maintain that it will take 3,333 hours to process the involuntary return of 50,000 customers to PG&E’s bundled services.

The assumptions provided by PG&E’s response to CalCCA 1.30 (as discussed in Advice Letter 5359-E and PG&E’s 2020 GRC), amounting to the four minutes, are based on the proxy amount equal to the Customer Re-Entry Service Fee for **voluntarily** returning CCA customers (separately) as established in PG&E’s Electric Schedule E-CCA.¹

The actual time required to switch involuntarily returned CCA customer service accounts to bundled service of PG&E, whether individually or in mass, will be calculated based on each actual involuntary return scenario(s) in accordance with the methodology provided in PG&E’s Electric Rule 23, Sections W and X, in their entirety.

¹ Electric Schedule E-CCA, Section 5b

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_002-Q014
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_002-Q014
Request Date:	April 15, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	April 24, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: CALCCA’S SECOND DATA REQUEST TO PG&E

QUESTION 014

Referring to PG&E’s Testimony, PG&E-3, page 9-1, Table 9-1:

- a. Please describe all of PG&E services, activities, and/or tasks associated with the Meter Data Management Fee. What is the most recent data PG&E has in its possession tracking the labor time associated with these services, activities, and/or tasks (and please provide that data)?
- b. Please describe all of PG&E services, activities, and/or tasks associated with the Rate-Ready Consolidated Billing Fee. What is the most recent data PG&E has in its possession tracking the labor time associated with these services, activities, and/or tasks (and please provide that data)?
- c. Please describe all of PG&E services, activities, and/or tasks associated with the Bill-Ready Consolidated Billing Fee. What is the most recent data PG&E has in its possession tracking the labor time associated with these services, activities, and/or tasks (and please provide that data)?

ANSWER 014

- a. The Meter Data Management Fee is a per meter per month composite fee and generally provides the service of collecting and supplying meter data to the CCAs/ESPs monthly. Meter data is made available in EDI 867 format and posted for retrieval by the CCAs/ESPs on PG&E’s Data Exchange Server (DES). Specific tasks and/or activities inherently associated with this service may include but, are not limited to:
 - a. Collection, validation, editing, and estimation (VEE) of interval usage data
 - b. Formatting and transmission of data to CCAs/ESPs via Electronic Data Interchange (EDI)
 - c. Account updates and data synchronization to support provider operations

- d. Storing and maintaining validated meter data in PG&E's Meter Data Management System (MDMS)
- e. Managing data exceptions, data correction, and data delivery/availability issues
- f. Maintaining system interfaces and processes required for third-party data delivery

Labor time is not tracked based on these specific tasks. Labor is tracked at the departmental or operational level to reflect broader internal task or human resource categories.

- b. The Rate-Ready Consolidated Billing Fee is a per account per billing cycle composite fee and generally covers the costs to present the CCA's/ESP's energy and customer charges on an additional bill page. It also includes the cost to process energy charges and customer payments and respond to CCA/ESP calls regarding billing issues. Specific tasks inherently associated with this service include, but are not limited to:
 - a. Setup, configuration/coding of CCA/ESP provided rate-structures in PG&E's billing system
 - b. Ongoing updates and maintenance of CCA or ESP rates
 - c. Billing validation and rate accuracy checks
 - d. Testing and validating rate logic to ensure accurate billing execution
 - e. Coordinating rate changes or new rate implementations with CCAs and ESPs
 - f. Ensuring timely updates and system readiness for rate-effective dates
 - g. Investigating rate-related billing exceptions or discrepancies
 - h. Providing customer service support related to rate-ready billing inquiries.

Labor time is not tracked based on these specific tasks. Labor is tracked at the departmental or operational level to reflect broader internal task or human resource categories.

- c. The Bill-Ready Consolidated Billing Fee is a per account per billing cycle composite fee and generally covers the cost to present the CCA's/ESP's energy and customer charges. It also includes costs to process energy charges and customer payments. Specific tasks inherently associated with this service include, but are not limited to:
 - a. Receipt and validation of customer billing data submitted by CCAs or ESPs via EDI
 - b. Integration and presentation of bill-ready charges on customer bills
 - c. Exception handling and coordination of bill corrections
 - d. Customer service support and dispute management
 - e. System maintenance and data validation related to third-party charges

Labor time is not tracked based on these specific tasks. Labor is tracked at the departmental or operational level to reflect broader internal task or human resource categories.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_002-Q015
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_002-Q015
Request Date:	April 15, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	April 24, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: CALCCA’S SECOND DATA REQUEST TO PG&E

QUESTION 015

Referring to PG&E’s Testimony, PG&E-3, page 9-1, Table 9-1:

- a. Please describe all of PG&E services, activities, and/or tasks associated with the Meter Data Management Fee as of PG&E’s (1) 2017 GRC II proceeding, and (2) 2020 GRC II proceeding.
- b. Please describe all of PG&E services, activities, and/or tasks associated with the Rate-Ready Consolidated Billing Fee as of PG&E’s (1) 2017 GRC II proceeding, and (2) 2020 GRC II proceeding.
- c. Please describe all of PG&E services, activities, and/or tasks associated with the Bill-Ready Consolidated Billing Fee as of PG&E’s (1) 2017 GRC II proceeding, and (2) 2020 GRC II proceeding.

ANSWER 015

- a. Services/activities/tasks associated with the Meter Data Management fee has remained consistent since PG&E’s 2017 GRC II proceeding to current. Please see PG&E’s response to GRC-2023-PhII_DR_CalCCA_002-Q014a for a description of the services/activities/tasks associated with this fee.
- b. Services/activities/tasks associated with the Rate-Ready Consolidated Billing fee has remained consistent since PG&E’s 2017 GRC II proceeding to current. Please see PG&E’s response to GRC-2023-PhII_DR_CalCCA_002-Q014b for a description of the services/activities/tasks associated with this fee.
- c. Services/activities/tasks associated with the Bill-Ready Consolidated Billing fee has remained consistent since PG&E’s 2017 GRC II proceeding to current. Please see PG&E’s response to GRC-2023-PhII_DR_CalCCA_002-Q014c for a description of the services/activities/tasks associated with this fee.

**PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response**

PG&E Data Request No.:	CalCCA_002-Q016
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_002-Q016
Request Date:	April 15, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	April 29, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: CALCCA’S SECOND DATA REQUEST TO PG&E

QUESTION 016

Referring to PG&E’s Testimony, PG&E-3, page 9-5, Table 9-4:

- a. Please explain if PG&E’s Billing Modernization Initiative is likely to, or could possibly, impact the costs associated with the Master Data Management Agent Fee?
- b. Please explain if PG&E’s Billing Modernization Initiative is likely to, or could possibly, impact the costs associated with the Rate-Ready Billing Fee?
- c. Please explain if PG&E’s Billing Modernization Initiative is likely to, or could possibly, impact the costs associated with the Bill-Ready Billing Fee?
- d. If any of the answers to parts (a) – (c) are in the affirmative: is PG&E planning to pass along any associated cost savings to customers? If so, please detail any and all such plans.

ANSWER 016

- a. PG&E’s Billing Modernization Initiative (BMI) may impact the costs associated with the Meter Data Management Agent (MDMA) fee. Planned system improvements are expected to enhance automation and reduce manual processing associated with MDMA-related functions. BMI is being implemented in three stages, and the system is still several years away from reaching Stage 3, the target state. As such, the full impact on MDMA-related costs remains uncertain, particularly given that multiple operational and system factors contribute to the MDMA fee.
- b. Similarly, the Rate-Ready Billing Fee may be impacted by BMI through improved automation and rate configuration capabilities. These enhancements could reduce manual effort, but any cost impact will depend on efficiencies realized in Stage 3. As with other fees, the Rate Ready Billing Fee reflects a combination of factors and is too early to determine whether or how the fee may change.

- c. The Bill-Ready Billing Fee could also be affected by system improvements under BMI. The platform is expected to support better handling of third-party bill components and data exchange, potentially lowering administrative overhead. As we are still in the early phases of BMI, any potential impacts will not be known until Stage 3 is complete and stabilized. The fee itself is influenced by various cost inputs and process requirements.
- d. If cost savings are realized from these upgrades, PG&E would evaluate adjustments to the applicable fees through the appropriate regulatory proceedings. PG&E does not currently have a formal plan to adjust the MDMA, Rate-Ready, or Bill Ready Billing fees, as any potential saving have not yet been realized or quantified. Final impacts will depend on system performance, implementation outcomes, and regulatory direction once the program reaches it's target state.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response

PG&E Data Request No.:	CalCCA_004-Q001
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_004-Q001
Request Date:	July 16, 2025
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	July 29, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: FOURTH DATA REQUEST OF CALCCA

QUESTION 001

Referring to PG&E's response to CalCCA request 1.27: For the employees that provide the service of Master Data Management Agent, please provide the following:

- a. Titles of the positions of the employees providing this service.
- b. Confirm whether each position listed in response to subpart (a) is classified as Exempt or Non-exempt.
- c. Confirm what employee group these positions would be included in from the categories listed in GRC-2023- PHII_DR_CalCCA_001-Q027 Atch01, page WP 4-21.
- d. Confirm what employee group these positions would be included in from the categories listed in GRC-2023- PHII_DR_CalCCA_001-Q027 Atch01, page WP 4-22.

ANSWER 001

While employee positions assigned to provide services are expected to change over time, the following table provides an estimate of those positions typically assigned to provide the service of Master Data Management Agent.

Customer Care Information Systems Analyst	Customer Care Information Systems Analyst, Senior	Exempt	Non-Represented Admin & Technical Bay Area; Non-Represented Admin & Technical Non - Bay Area; Management Bay Area;	A&G; Operating

Customer Care Information Systems Analyst, Expert		Management Non-Bay Area	
Billing Energy Data Services Supervisor			
Complex Billing Manager			

¹ Position titles and their respective exemption status and categories of employees assigned to provide this service are subject to change.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response

PG&E Data Request No.:	CalCCA_004-Q002
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_004-Q002
Request Date:	July 16, 2025
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	July 29, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: FOURTH DATA REQUEST OF CALCCA

QUESTION 002

Referring to PG&E's response to CalCCA request 1.27: For the employees that provide the service of Rate-Ready Billing, please provide the following:

- a. Titles of the positions of the employees providing this service.
- b. Confirm whether each position listed in response to subpart (a) is classified as Exempt or Non-exempt.
- c. Confirm what employee group these positions would be included in from the categories listed in GRC-2023- PHII_DR_CalCCA_001-Q027 Atch01, page WP 4-21.
- d. Confirm what employee group these positions would be included in from the categories listed in GRC-2023- PHII_DR_CalCCA_001-Q027 Atch01, page WP 4-22.

ANSWER 002

While employee positions assigned to provide services are expected to change over time, the following table provides an estimate of those positions typically assigned to provide the service of Rate-Ready Billing.

Customer Service Representative	Non-Exempt	IBEW Represented Employees	Operating
Service Representative I			

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Billing Operations Supervisor Billing Operations Manager Complex Billing Manager Business Analyst, Senior Business Analyst, Expert	Exempt	Management Bay Area; Management Non-Bay Area	A&G; Operating

¹ Position titles and their respective exemption status and categories of employees assigned to provide this service are subject to change.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response

PG&E Data Request No.:	CalCCA_004-Q003
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_004-Q003
Request Date:	July 16, 2025
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	July 29, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

SUBJECT: FOURTH DATA REQUEST OF CALCCA

QUESTION 003

Referring to PG&E's response to CalCCA request 1.27: For the employees that provide the service of Bill-Ready Billing, please provide the following:

- a. Titles of the positions of the employees providing this service.
- b. Confirm whether each position listed in response to subpart (a) is classified as Exempt or Non-exempt.
- c. Confirm what employee group these positions would be included in from the categories listed in GRC-2023- PHII_DR_CalCCA_001-Q027 Atch01, page WP 4-21.
- d. Confirm what employee group these positions would be included in from the categories listed in GRC-2023- PHII_DR_CalCCA_001-Q027 Atch01, page WP 4-22.

ANSWER 003

While employee positions assigned to provide services are expected to change over time, the following table provides an estimate of those positions typically assigned to provide the service of Bill-Ready Billing.

Customer Service Representative	Non-Exempt	IBEW Represented Employees	Operating
Service Representative I			

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Billing Operations Supervisor Billing Operations Manager Complex Billing Manager Business Analyst, Senior Business Analyst, Expert	Exempt	Management Bay Area; Management Non-Bay Area	A&G; Operating

¹ Position titles and their respective exemption status and categories of employees assigned to provide this service are subject to change.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response

PG&E Data Request No.:	CalCCA_005-Q001
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_005-Q001
Request Date:	July 30, 2025
Requester DR No.:	005
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	August 13, 2025
PG&E Witness(es):	Thomas Wong – Customer and Enterprise Solutions

QUESTION 001

Referring to PG&E-4, Appendix I:

- (a) Please explain why PG&E is not proposing to update the POLR fee in this case.
- (b) Please confirm the year(s) in which the inputs and assumptions that go into PG&E's calculation of its POLR fee were determined/last updated (i.e., in what year did PG&E determine that four minutes of a Customer Service Representative's time was the appropriate labor input, and in what year did it determine that \$57.89/hour was the appropriate labor cost input)? What year(s) of data were used to calculate those labor and labor cost inputs?
- (c) Please explain what, if anything, PG&E intends to do to address the Commission's finding in D.24-04-009 that the discrepancy between PG&E's POLR fee and those charged by the other two IOUs is "concerning."

ANSWER 001

- (a) At this time, PG&E does not feel the need to update this fee because it represents a proxy amount for switching CCA service back to PG&E bundled service on a customer-by-customer basis. The scenario can differ based on the actual CCA involuntary return event. For example, an actual CCA involuntary return event may provide some customer switching data individually and/or some in the form of a mass listing. For a mass listing, PG&E may be able to process their switching in batch(es) to maximize efficiency and thus possibly reducing the overall actual cost. Whatever the scenario, PG&E intends to conform with the procedures provided by its Rule 23, Sections W and X, in their entirety, if and when a CCA experiences an involuntary customer return event. This enables PG&E to capture the actual tasks involved on a case by case scenario basis using the then labor and labor cost inputs in accordance with the procedures outlined in Rule 23 designed to more accurately address each event to determine the actual cost to charge each applicable CCA.
- (b) The data used to calculate the labor and labor cost inputs associated with the current POLR fee was based on 2015 data.

(c) PG&E have responded to the Commission's request for additional data in connection with D.24-04-009 by providing how the POLR fee was determined in Appendix I in the current 2023 GRC Ph. II proceeding. PG&E will continue to respond to any further concerns, if any, by the Commission. PG&E has no intention to further address the Commission on that matter at this time because, as we have explained in subpart (a), the current POLR fee is a proxy amount and the actual cost for switching customers from a CCA back to PG&E's bundled service will be calculated in accordance with procedures outlined in our Rule 23, Sections W and X, to determine the actual cost to charge a CCA based on each different CCA involuntary return event scenario.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response

PG&E Data Request No.:	CalCCA_007-Q001
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_007-Q001
Request Date:	February 20, 2026
Requester DR No.:	007
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	March 5, 2026
PG&E Witness(es):	Thomas Wong, Amitava Dhar – Corporate Affairs

QUESTION 001

Referring to PG&E’s response to CalCCA request 5.02:

- a. Please explain why PG&E generally reviews and considers updating CCA service fees during a GRC Phase II proceeding. Is it because all costs and cost studies are established in a Phase I proceeding and then rates can be determined in the Phase II based on those costs established in the Phase I? If not, please explain.
- b. Please confirm or deny that CCA service fees should be based on cost of service principles. If deny, please explain.
- c. Please confirm or deny that up-to-date cost studies are the generally accepted method for establishing cost of service for utility costs. If deny, please explain.

ANSWER 001

- a. Yes. Our current ask as part of Phase II is only to account for labor escalations based on previously established fees.
- b. Confirmed.
- c. Confirmed, but there can be instances where PG&E may not use the *most* up-to-date cost studies. For example, in this GRC Phase II proceeding the cost studies are generally linked to PG&E’s 2023 GRC I costs, despite more recent costs existing. This is because this GRC II proceeding serves to allocate the costs/revenues established and authorized in the 2023 GRC I proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response

PG&E Data Request No.:	CalCCA_007-Q002
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_007-Q002
Request Date:	February 20, 2026
Requester DR No.:	007
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	March 5, 2026
PG&E Witness(es):	Paulina Pra – Corporate Affairs

QUESTION 002

Please provide the average annual number of unbundled customers, bundled customers, and total customers on the PG&E system for the years 2015, 2016, 2017, 2018, 2019, 2020, 2021, 2022, 2023, 2024 and 2025. If PG&E does not calculate the average annual number of unbundled and bundled customers, please provide the number of unbundled and bundled customers at the end of each calendar quarter of the years listed above.

ANSWER 002

PG&E provides the requested information regarding the average annual number of unbundled customers, bundled customers, and total customers on the PG&E electric system for the years 2015 through 2025. This data is set forth in the table below.

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Attachment KJC-3
PG&E Responses to CCA Discovery Requests in
A.25-05-009, A.24-10-014, and A.21-06-021

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q006
PG&E File Name:	BillingModernization_DR_PCE_001-Q006
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

QUESTION 006

Referring to PG&E’s Prepared Testimony, Chapter 2, p. 2-6, lines 16 to 34, and p. 2-7, lines 1 to 2: Please confirm if improvements to the Third-Party Energy Service Provider Management system under PG&E’s BMI will lead to lower CCA service fees. If confirmed, please explain, outlining the specific CCA service fees that will be lowered and the estimated reduction amount for each service fee.

ANSWER 006

While PG&E’s BMI (Billing Modernization Initiative), including the transition to the C2M platform, is expected to improve efficiency in managing and supporting third-party energy service providers such as Community Choice Aggregators (CCAs), it is not possible at this time to confirm whether those improvements will directly result in lower CCA service fees.

Although the new C2M platform introduces streamlined processes, reduced reliance on manual interventions, and consolidated systems, which collectively create operational efficiencies the potential impact on CCA service fees is subject to several factors. These include regulatory requirements, future operational needs, and unforeseen system complexities that may emerge as the new platform is implemented and scaled.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q007
PG&E File Name:	BillingModernization_DR_PCE_001-Q007
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

QUESTION 007

Referring to PG&E’s Prepared Testimony, Chapter 2, p. 2-6, lines 16 to 34, and p. 2-7, lines 1 to 2: Please explain which specific components of PG&E’s billing management system that will be upgraded or added under PG&E’s BMI will lead to lower CCA service fees.

ANSWER 007

The Billing Modernization Initiative is not focused on replacing a single component of the billing management system but is instead a comprehensive re-platforming effort. Specifically, it involves transitioning from the current Meter Data Management (MDM), Customer Care & Billing (CC&B) system, and ABS/BCS billing systems (Refer to Figure 2-1).

While this transformation is expected to drive efficiencies such as reducing manual interventions, streamlining data exchanges, and improving billing, the Initiative is not intended to target specific reductions in CCA service fees. It is not possible at this time to quantify how these efficiencies may affect CCA service fees due to evolving regulatory guidance, future operational impacts, and the complexity of cost allocation. PG&E cannot confirm that these upgrades will directly result in lower CCA services fees, nor identify which specific components would lead to a reduction in the CCA service fee.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q023
PG&E File Name:	BillingModernization_DR_PCE_001-Q023
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

QUESTION 023

Referring to PG&E’s Prepared Testimony, Chapter 4, p. 4-11, lines 12 to 18: how will this improved functionality for the target state billing system impact CCA service fee costs, and how and on what timeline does PG&E plan to pass these cost savings along to CCAs?

ANSWER 023

PG&E is still in the early stages of implementing its Billing Modernization Initiative (BMI), and the system is not expected to reach its target state (Stage 3) for several more years. As a result, it is too early to quantify the cost impacts of these improvements, including any specific reductions to CCA service fee costs. It’s also important to note that the CCA service fees are based on a range of cost drivers.

The functionality referred to in Chapter 4, p.4-11, lines 12 to 18 will become available with the implementation of the target system.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_002-Q011
PG&E File Name:	BillingModernization_DR_PCE_002-Q011
Request Date:	May 20, 2025
Requester DR No.:	002
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	June 3, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

SUBJECT: SECOND DATA REQUEST OF PCE

QUESTION 011

Referring to PG&E's response to PCE_001_Q006:

- a. Please explain how PG&E currently sets these CCA service fees (i.e., PG&E's methodology for determining the appropriate fee amounts).
- b. Does PG&E anticipate continuing to use this same methodology referenced in part (a) after the BMI upgrades? If not, please explain any anticipated changes to PG&E's methodology.
- c. Please confirm if PG&E applies and will continue to apply an inflation factor to determine CCA service fees. If confirmed, please explain how this inflation factor is calculated.
- d. If part (c) is confirmed, please explain if PG&E expects CCA service fees to increase over time due to the application of an inflation factor.
- e. Does PG&E anticipate that its implementation of the BMI will, on balance, improve efficiency in supporting CCAs? If not answered in the affirmative, please explain why.
- f. All else being equal, would the referenced "streamlined processes" lead to reduced CCA service fees? If not, why not.
- g. All else being equal, would the referenced "reduced reliance on manual interventions" lead to reduced CCA service fees? If not, why not.
- h. All else being equal, would the referenced "consolidated systems" lead to reduced CCA service fees? If not, why not.
- i. Please provide examples of the kinds of "regulatory requirements" that might raise CCA service fees in the future. What does PG&E mean by that phrase in this context?

- j. Please provide examples of the kinds of “future operational needs” that might raise CCA service fees in the future. What does PG&E mean by that phrase in this context?
- k. Please provide examples of the kinds of “unforeseen system complexities” that might raise CCA service fees in the future. What does PG&E mean by that phrase in this context?
- l. Referring also to PG&E’s response to PCE_001_Q007, please explain what PG&E means by “the complexity of cost allocation”, and specifically, how that complexity could raise CCA service fees in the future.

ANSWER 011

- a. PG&E’s CCA service fees listed in Electric Schedule E-CCA are developed based on the estimated labor time, materials, system usage, and administrative effort required to perform each service. Fee calculations typically reflect internal cost-of-service estimates, consistent with principles used in other unbundled service fee determinations. Fees are reviewed and approved through applicable regulatory proceedings and are maintained by various operational groups across the company.
- b. PG&E anticipates continuing to use a similar cost-based methodology post-BMI. Once BMI is fully implemented and the new system has stabilized, PG&E may revisit the inputs and assumptions behind the fee calculations to reflect changes in system design, automation, and labor effort associated with performing the underlying services.
- c. Yes, in applicable proceedings PG&E has applied an inflation or escalation factors based on expected labor cost growth. This typically reflects enterprise-wide labor escalation rates or other cost forecast factors reviewed in general rate case (GRC) proceedings.
- d. Yes, if the inflation factor continues to be applied, PG&E would expect that certain CCA service fees could increase over time, subject to regulatory approval.
- e. Yes, PG&E anticipates that, once fully implemented, the BMI will improve operational efficiency in supporting CCA-related services. These improvements are expected to stem from increased automation, data standardization, and streamlined workflows. The full benefits of BMI are not expected to be realized until the final stages of BMI.
- f. While the BMI is designed to streamline many operational processes, not every process will be streamlined. As PG&E retires decades of custom code and adopts standardized base-product workflows, certain services may experience increased processing time or operational complexity. In some cases, efficiencies in one area may be offset by additional steps or requirements in another. The overall impact is expected to vary across services and may balance out across multiple processes. Any potential impact on service fees would be assessed through a comprehensive cost review and subject to Commission approval.
- g. Reduced manual intervention is expected to improve efficiency and reduce the risk of human error for certain processes. The extent of cost savings will vary depending on service complexity, volume, and system design. Reductions in administrative

effort may not directly translate into lower service fees without a post-implementation cost analysis.

- h. Consolidating systems may reduce data duplication, streamline reporting, and lower maintenance burdens. However, initial implementation and transition costs may offset these efficiencies in the near term. Any long-term fee adjustments would depend on operational cost impacts following full deployment and would be subject to Commission review.
- i. Regulatory requirements that could increase CCA service fees in the future may include, but are not limited to, new or evolving obligations that introduce additional complexity, system enhancements, or administrative workload. Examples include:
 - a. Provider of Last Resort (POLR) Implementation: as PG&E steps into new roles related to POLR, including mass transitioning CCA customers back to bundled service in the event of a CCA failure or market exit, new processes are being developed that do not currently exist within legacy systems.
 - b. Data Privacy and Compliance Mandates: regulations such as California Consumer Privacy Act (CCPA) and potential future legislation may require enhancements to data handling processes, consent tracking, customer communication protocols and data reporting. Compliance with these laws may lead to increased system and labor costs associated with managing CCA customer data in a compliant manner.
 - c. Customer Billing and Notification Enhancements: Commission directives requiring changes to bill presentment (e.g., inclusion of dynamic rate components or standardizing messaging)

These examples reflect that CCA services fees may affect not only by system efficiencies but also by additional complexity introduced by emerging regulatory frameworks.

- j. “Future operational needs” refer to changes in business practices, staffing, systems, or support processes that may arise to maintain or improve service delivery that could impact CCA service fees.
- k. “Unforeseen system complexities” refer to technical or integration challenges that are not identified until after system implementation that may increase service costs
- l. “Complexity of cost allocation” refers to the challenge of assigning shared systems or operational costs across various customer groups and services. Example: determining the appropriate portion of shared IT infrastructure costs attributable to CCA related services.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	JointCCAs_014-Q003		
PG&E File Name:	GRC-2023-PhI_DR_JointCCAs_014-Q003		
Request Date:	April 28, 2022	Requester DR No.:	014
Date Sent:	May 13, 2022	Requesting Party:	City and County of San Francisco/ East Bay Community Energy/ Marin Clean Energy/ Peninsula Clean Energy Authority/ Pioneer Community Energy/ San José Clean Energy/ Silicon Valley Clean Energy Authority/ Sonoma Clean Power Authority
PG&E Witness:	Matt Briel	Requester:	Jacob Schlesinger

QUESTION 003

- a. Referring to PG&E-6, please provide the 2023 projected hourly rate for a CSR that would be included in MWC DK.
- b. Referring to PG&E-6, please provide the 2023 projected hourly rate for a CSR that aligns with the hourly rate used to calculate the re-entry fee in Electric Schedule E-CCA, as described in PG&E Advice Letter 5359-E, footnote 2.

ANSWER 003

- a. Referring to PG&E-6, the 2023 projected hourly wage rate for a CSR included in MWC DK is \$37.07.
- b. PG&E will respond to this question at a later date.

PACIFIC GAS AND ELECTRIC COMPANY
2027 General Rate Case Phase I
Application 25-05-009
Data Response

PG&E Data Request No.:	CalCCA_002-Q022
PG&E File Name:	GRC-2027-PhI_DR_CalCCA_002-Q022
Request Date:	September 12, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 26, 2025
PG&E Witness(es):	Rakesh Nigam – Customer and Enterprise Solutions

QUESTION 022

Referring to PG&E’s Prepared Testimony PG&E-6, p. 6-1, lines 10-17:

- (a) Does PG&E’s cost request in this case for “Billing Operations”, as the term is used in this excerpt, include costs associated with billing services to CCA customers?
- (b) Does PG&E’s cost request in this case include costs associated with the billing service fees ultimately charged to CCA customers (e.g., the Master Data Management Agent Fee, the Rate-Ready Billing Fee, and the Bill-Ready Billing Fee)? If yes, please indicate the workpaper line number(s) associated with those costs. If no, please explain why not.

ANSWER 022

- a. The costs associated with third-party billing are covered by the billing service fees that are collected. Therefore, the costs associated with services related to CCA exceptions/processing are offset by the billing service fees collected from CCA customers.
- b. The billing service fees are recorded within Major Work Category (MWC) IS and AR. These costs and billing service fees are associated with WP 6-1 line 1 and line 3.

PACIFIC GAS AND ELECTRIC COMPANY
2027 General Rate Case Phase I
Application 25-05-009
Data Response

PG&E Data Request No.:	CalCCA_005-Q016
PG&E File Name:	GRC-2027-Phi_DR_CalCCA_005-Q016
Request Date:	October 29, 2025
Requester DR No.:	005
Requesting Party:	California Community Choice Association
Requester:	Gonzalo E. Rodriguez
Date Sent:	November 13, 2025
PG&E Witness(es):	Rakesh Nigam – Customer and Enterprise Solutions

QUESTION 016

Please refer to PG&E’s response to DR CCA 002-022. Please provide specific line-item detail of costs specific to billing CCA customers within WP 6-1 line 1 and line 3.

ANSWER 016

PG&E does not track specific costs solely associated with CCA customers. Instead, CCA and Direct Access (DA) customers’ costs are tracked under the same planning orders. Please refer to attachment “*GRC-2027-Phi_DR_CalCCA_005-Q016Atch01.xlsx*” for information for detail of costs associated with CCA and DA customers within lines 1 and 3 for WP 6-1.

Pacific Gas and Electric Company
CalCCA-005, Question 16
Exhibit (PG&E-6), Chapter 6
Billing, Revenue and Credit
(Thousand of Nominal Dollars)

Line No.	MWC	Planning Order	Planning Order Name	2020 Recorded	2021 Recorded	2022 Recorded	2023 Recorded	2024 Recorded
1	AR	5035776	CCA/DA - MDMA - MWC AR - CB	\$ 2,639	\$ 2,109	\$ 1,427	\$ 1,134	\$ 740
2	AR	5038851	CCA/DA - MDMA Revenue - CB	\$ (3,758)	\$ (4,038)	\$ (4,222)	\$ (4,265)	\$ (4,283)
3	AR	5045837	CCA/DA - MDMA - MWC AR - BOE	\$ 6	\$ 10	\$ 1,864	\$ 1,272	
4			MWC AR Total	\$ (1,112)	\$ (1,920)	\$ (931)	\$ (1,859)	\$ (3,543)
5	IS	5030654	CCA - Billing Revenue - CB	\$ (5,289)	\$ (5,916)	\$ (6,209)	\$ (6,299)	\$ (6,325)
6	IS	5041471	CCA/DA - Billing Systems & Analytics	\$ 47	\$ 35	\$ 33	\$ 6	
7	IS	5041511	CCA/DA - Billing - CB	\$ 1,004	\$ 1,087	\$ 880	\$ 834	\$ 804
8	IS	5030653	CCA/DA - Billing Exceptions	\$ 2,700	\$ 3,098	\$ 5,222	\$ 6,815	\$ 6,529
9			MWC IS Total	\$ (1,538)	\$ (1,695)	\$ (75)	\$ 1,355	\$ 1,008

**PACIFIC GAS AND ELECTRIC COMPANY
2027 General Rate Case Phase I
Application 25-05-009
Data Response**

PG&E Data Request No.:	CalCCA_014-Q002
PG&E File Name:	GRC-2027-Phi_DR_CalCCA_014-Q002
Request Date:	January 22, 2026
Requester DR No.:	014
Requesting Party:	California Community Choice Association
Requester:	Gonzalo E. Rodriguez
Date Sent:	January 30, 2026
PG&E Witness(es):	Ivana Tamburrino, Shetal Chaturvedi – Finance

QUESTION 002

Refer to line numbers 19-27 on Page 2-4 of Exhibit 10, Chapter 2. Do the customer support costs being referred to include O&M expenses recorded to FERC Accounts 901-916? If not, how are customer costs recorded in FERC Accounts 901-916 functionally allocated?

ANSWER 002

Yes, customer support costs include O&M expenses recorded to FERC accounts 901-916.

**PACIFIC GAS AND ELECTRIC COMPANY
2027 General Rate Case Phase I
Application 25-05-009
Data Response**

PG&E Data Request No.:	CalCCA_014-Q004
PG&E File Name:	GRC-2027-PhI_DR_CalCCA_014-Q004
Request Date:	January 22, 2026
Requester DR No.:	014
Requesting Party:	California Community Choice Association
Requester:	Gonzalo E. Rodriguez
Date Sent:	February 5, 2026
PG&E Witness(es):	Rakesh Nigam – Customer and Enterprise Solutions

QUESTION 004

Refer to PG&E’s response to DR005-016. Please provide the forecast for 2025-2030 used in developing the GRC for the planning orders specified in Attachment 1.

ANSWER 004

Please refer to attachment “*GRC-2027-PhI_DR_CalCCA_014-Q004Aatch01.xlsx*” for the 2025-2027 forecasts. PG&E did not provide forecasts for 2028-2030 since the applicable planning orders are expense.

**Pacific Gas and Electric Company
CalCCA_014, Question 4
Exhibit (PG&E-6), Chapter 6
Billing, Revenue and Credit
(Thousand of Nominal Dollars)**

Line No.	MWC	Planning Order	Planning Order Name	2025 Forecast	2026 Forecast	2027 Forecast
1	AR	5035776	CCA/DA - MDMA - MWC AR - CB	\$ 767	\$ 797	\$ 826
2	AR	5038851	CCA/DA - MDMA Revenue - CB	\$ (3,986)	\$ (3,550)	\$ (3,550)
3	AR	5045837	CCA/DA - MDMA - MWC AR - BOE			
4			MWC AR Total	\$ (3,220)	\$ (2,754)	\$ (2,724)
5	IS	5030654	CCA - Billing Revenue - CB	\$ (6,753)	\$ (6,818)	\$ (6,818)
6	IS	5041471	CCA/DA - Billing Systems & Analytics			
7	IS	5041511	CCA/DA - Billing - CB	\$ 804	\$ 804	\$ 834
8	IS	5030653	CCA/DA - Billing Exceptions	\$ 6,600	\$ 6,600	\$ 6,847
9			MWC IS Total	\$ 651	\$ 586	\$ 863

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

Application of Marin Clean Energy for
Approval of 2028-2031 Energy Efficiency
Portfolio Plan and 2032-2035 Energy
Efficiency Portfolio Plan

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

**APPLICATION OF MARIN CLEAN ENERGY
FOR APPROVAL OF
2028-2031 ENERGY EFFICIENCY PORTFOLIO PLAN
AND
2032-2035 ENERGY EFFICIENCY BUSINESS PLAN**

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March 16, 2026

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**BEFORE THE PUBLIC UTILITIES COMMISSION
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Application 26-03-____
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**APPLICATION OF MARIN CLEAN ENERGY
FOR APPROVAL OF
2028-2031 ENERGY EFFICIENCY PORTFOLIO PLAN
AND
2032-2035 ENERGY EFFICIENCY BUSINESS PLAN**

I. INTRODUCTION

Marin Clean Energy (“MCE”) respectfully submits this Application for approval of its 2028-2031 energy efficiency (“EE”) Portfolio Plan and its 2032-2035 EE Business Plan¹ pursuant to Article 2 of the California Public Utilities Commission’s (“Commission” or “CPUC”) Rules of Practice and Procedure, California Public Utilities Code § 381.1, and Decisions (“D.”) 21-05-031² and D.23-06-055.³

MCE has successfully administered EE programs for well over a decade.⁴ MCE’s EE programs have consistently delivered energy savings while also providing meaningful customer

¹ MCE’s 2028-2031 EE Portfolio Plan and 2032-2035 EE Business Plan are included as Exhibit 1 of the testimony served with this Application. While the Commission initially envisioned PA Business Plans to cover an eight-year period (*see* Decision (“D.”) 21-05-031, Ordering Paragraph (“OP”) 5), per discussions with Energy Division (and the template developed pursuant to D.21-05-031, OP 6), MCE is providing a Business Plan covering the four years after the conclusion of the Portfolio Plan.

² Rulemaking (“R.”) 13-11-005, D.21-05-031, *Assessment of Energy Efficiency Potential and Goals and Modification of Portfolio Approval and Oversight Process* (May 20, 2021).

³ Application (“A.”) 22-02-005 *et al.*, D.23-06-055, *Decision Authorizing Energy Efficiency Portfolios for 2024-2027 and Business Plans for 2024-2031* (June 29, 2023).

⁴ D.12-11-015, *Decision Approving 2013-2014 Energy Efficiency Programs and Budgets*, p. 50, OP 1 (November 15, 2012) (approving MCE EE portfolio).

and community benefits.⁵ Though MCE’s programs have primarily benefited communities local to MCE’s service area, those programs have also supported the equitable growth of the EE, electrification, and demand side management markets statewide. Through this Application, MCE seeks Commission approval to continue to deliver a balanced and diverse portfolio of EE programs to its residential, commercial, industrial, public, and agricultural customers.

MCE’s four-year Portfolio Plan, covering the 2028-2031 period, largely builds on the successes of its existing portfolio of programs, with innovative additions to address a refrigerant regulatory gap facing small businesses, and to launch a new single-family residential Resource Acquisition program modeled on MCE’s successful Equity program. MCE’s Business Plan, covering the 2032-2035 period, provides a longer-term strategic vision that is consistent with the near-term tactics and objectives in MCE’s Portfolio Plan. MCE’s Business Plan and Portfolio Plan, in concert, chart a path for MCE to scale the impact of its EE programming, support California’s decarbonization goals, and ensure ratepayer funds are used efficiently and effectively for these ends. The Commission should approve both proposals, including MCE’s annual budgets for program years (“PY”) 2028-2035.⁶ Informed by its experience administering programs in its PYs 2024-2027 portfolio and by the energy affordability crisis in California—which necessitates greater scrutiny of ratepayer funds⁷—MCE requests a \$14.8 million reduction in its 2028-2031

⁵ See Marin Clean Energy, Customer Programs & Offerings, available at: <https://www.mcecleanenergy.org/customer-programs/>.

⁶ MCE expects that its 2028-2035 budget, once approved, will set the budget cap for the eight-year period, while its 2028-2031 zero-based budget will establish its portfolio period spending budget. MCE understands the Commission considers its approval of 2032-2035 budgets as forecasts for planning purposes.

⁷ Sierra Club, California’s Affordability Crisis: Utilities Asking for More Money for Shareholders, November 2025, available at: <https://www.sierraclub.org/articles/2025/11/california-s-affordability-crisis-utilities-asking-more-money-shareholders>; Executive Department State of California, EXECUTIVE ORDER N-5-24, October 30, 2024, available at: <https://www.gov.ca.gov/wp->

budget,⁸ constituting a 19 percent four-year budget reduction.

MCE also requests that the Commission update and clarify its policies to reflect the value that EE Program Administrators’ (“PA”) Equity and Market Support programs have achieved for California ratepayers since they were last approved in the 2024-2027 application cycle. First, MCE requests that the Commission reconsider its current 30 percent budget cap on Equity and Market Support segments for community choice aggregator (“CCA”) PAs, and instead adopt a more flexible limit that permits MCE to adjust its Equity segment budget cap to be more proportional to the level of Equity customers⁹ within MCE’s service territory.

Second, MCE requests the Commission clarify that the budget cap limit on expenditures for Equity and Market Support customers is a budget cap for the *entire* portfolio period and is fully authorized at the time of an Application decision—*i.e.*, it operates as a cap that limits the four-year spend for this customer group. Advice Letters (“AL”) and check-ins during the portfolio period are important to make sure PAs are approximately on track and have a plan to ensure that ultimate expenditures comply with any Commission-imposed caps. However, in MCE’s experience, Energy Division has adopted an approach to budgeting that the Commission never contemplated, and that interferes with PAs’ ability to operate their programs in an efficient, cost-effective, and flexible manner, responsive to normal fluctuations in customer demand. This approach improperly lowered MCE’s Equity and Market Support budgets by \$2,346,187.77 based on MCE’s slower

<content/uploads/2024/10/energy-EO-10-30-24.pdf>, pp. 1-2; Assembly Bill 3264 (Petrie-Norris), sec. 1(b), 3(b).

⁸ D.23-06-055, p. 94 (authorizing a 2028-2031 \$80,063,445 budget forecast for MCE).

⁹ MCE refers to all categories of customers eligible for its proposed Equity segment programs using the umbrella term “Equity customers.” Consistent with D.21-05-031 and D.23-06-055, MCE defines “Equity customers” as residential customers and businesses within identified “Environmental and Social Justice Communities” (“ESJ Communities”) by the Commission’s Environmental and Social Justice Action Plan. *See Exhibit 1, Chapter 6, Section 5.1.*

deployment of Resource Acquisition programs (which caused the percent of outlaid Equity and Market Support funds to exceed the total portfolio period's budget cap of 30 percent).

The Commission should therefore take this opportunity to clarify both that (1) a CCA PA should be permitted to adjust its Equity budget cap to reflect the proportionate share of Equity customers in that PA's portfolio, and (2) the Equity budget cap applies to the portfolio period *as a whole*, and PAs should not have their budgets reduced if their initial investments across programs cause the Equity and Market Support budgets to slightly outpace the percentage of the total budgets that they will ultimately spend.

II. BACKGROUND

Since its founding as California's first CCA in 2010, MCE has steadily increased the number of communities it serves, the customer programs it offers, and the impact it achieves. Today, MCE serves over 1.5 million residential and non-residential customers in 38 diverse member communities across four San Francisco Bay Area counties (Marin, Napa, Solano, and Contra Costa counties). MCE is the primary electric service provider in its service area and provides innovative customer programs that span the entire breadth of distributed energy resources ("DERs").¹⁰

Energy efficiency is a pillar of MCE's mission and vision, and a critical resource to serve its customers' load.¹¹ MCE initially applied to administer EE programs in 2012, soon after its inception.¹² While the Commission initially restricted MCE to serving gaps in the investor-owned

¹⁰ See Marin Clean Energy, Customer Programs & Offerings, available at: <https://www.mcecleanenergy.org/customer-programs/>.

¹¹ See Marin Clean Energy, About Us, available at: <https://www.mcecleanenergy.org/about-us/>.

¹² Application of Pacific Gas and Electric Company for Approval of 2013-2014 Energy Efficiency Programs and Budget, A.12-07-001 *et al.* (Jul. 2, 2012).

utilities’ (“IOU”) EE programs,¹³ the Commission subsequently lifted that restriction and allowed MCE to offer a more comprehensive portfolio of cost-effective EE programs.¹⁴

MCE filed its most recent application for Commission approval of its EE portfolio in 2022 (Application (“A.”) 22-02-005 (consolidated)).¹⁵ That portfolio included a comprehensive set of programs serving the residential single-family, residential multi-family, commercial, industrial, and agricultural sectors, and met the Commission’s cost-effectiveness requirements. The Commission approved MCE’s proposed portfolio of programs and associated budgets in D.23-06-055.¹⁶ It noted that MCE had “been administering [its] own portfolio[] for a decade,” and that MCE’s proposal had generally segmented its portfolio appropriately.¹⁷

Since that decision, MCE has steadily refined the scope of its EE portfolio, launching multiple new programs for its residential and non-residential customers, including Equity segment programs. For example, in 2024 MCE launched its Small Business Energy Advantage (“SBEA”) program, which provides commercial Equity customers free, on-site energy assessments along with financial incentives to install energy-efficient upgrades. Late last year, the Commission approved MCE’s Integrated Demand-Side Management (“IDSMS”) program, offering commercial and residential customers incentives for daily load shifting and load reduction during peak hours.¹⁸ And only two months ago, MCE launched a new Resource Acquisition program for residential

¹³ A.12-07-001 *et al.*, D.12-11-015, *Decision Approving 2013-2014 Energy Efficiency Programs and Budgets*, pp. 45-46 (Nov. 8, 2012).

¹⁴ See R.09-11-014, D.14-01-033, *Decision Enabling Community Choice Aggregators to Administer Energy Efficiency Programs*, OP 3 (Jan. 16, 2014).

¹⁵ See A.22-02-005 *et al.*, Application of Marin Clean Energy for Approval of 2024-0231 Energy Efficiency Business Plan and 2024-2027 Energy Efficiency Portfolio Plan (Mar. 4, 2022).

¹⁶ D.23-06-055, OP 5-6.

¹⁷ *Id.*, pp. 14, 16.

¹⁸ Resolution E-5387 (with a September 23, 2025 date of issuance).

customers (the Multi-Family Energy Savings-Resource program) modeled on its successful Equity-focused Multi-Family Energy Savings-Equity program.

MCE looks forward to presenting its proposals to methodically and conscientiously expand, refine, and better target its EE offerings to ensure the Commission’s goals for the state’s EE programs are delivered in an efficient, collaborative, and transparent manner.

III. LEGAL AND POLICY FRAMEWORK

MCE has administered EE programs under the authority granted in Cal. Pub. Util. Code § 381.1(a)-(d) since 2013. On May 20, 2021, the Commission issued an Order significantly modifying the EE portfolio approval and oversight process.¹⁹ Decision 21-05-031 created the obligation for PAs to file EE applications in 2026 containing the following elements:

1. A four-year portfolio plan, providing a detailed description of the EE portfolio and budget for PYs 2028-2031. The Commission requires that the portfolio plan specifically contain: detailed sector and program strategies; annual budgets, totaling to a four-year revenue requirement; cost-effectiveness showings over the four-year period; and program implementation plans.
2. A business plan describing the PA’s strategic EE plan for PYs 2032-2035, and containing sector-level strategies, metrics, and a budget.²⁰

In April 2023, D.23-04-035 limited ratepayer-funded incentives for natural gas energy efficiency measures related to combustion (exempting efficiency measures unrelated to combustion).²¹ MCE’s Application complies with this decision by proposing no cost-ineffective,

¹⁹ D.21-05-031.

²⁰ D.23-06-055, p. 26.

²¹ A.22-02-005, D.23-04-035, *Decision Addressing Codes and Standards Subprograms and Budgets and Staff Proposal on Reducing Ratepayer-Funded Incentives for Gas Energy Efficiency Measures*, OPs 3, 6.

non-exempt gas measures, and it includes a comprehensive strategy for promoting and deploying exempt measures in its Equity segment.

In June 2023, the Commission approved the PAs' first round of applications under these new requirements in D.23-06-055.²² Decision 23-06-055 also directed several changes to EE policy and the EE program approval and oversight process. The most notable changes include: (1) adopting changes to the general portfolio oversight process through new objectives, goals, and a stakeholder group;²³ (2) updating metrics and goals (*e.g.*, expanding the use of normalized metered energy consumption) and initiating processes to develop recommendations regarding new metrics and goals;²⁴ and (3) adopting changes to definitions, objectives, and indicators for the Equity segment.²⁵ This decision also reiterated the value the Commission places on all EE PAs working together, with Commission staff, and through various working groups to produce reports and propose policies and metrics.²⁶

Accordingly, MCE files this Application, which requests Commission approval of MCE's four-year EE Portfolio Plan and subsequent four-year EE Business Plan (included as Exhibit 1 in MCE's testimony). MCE's Portfolio Plan and Business Plan comply with each of the filing and substantive requirements in D.21-05-031, D.23-06-055, and prior Commission decisions.

In addition to these Commission decisions, other legislative directives and aspects of state policy also impacted the development of MCE's 2028-2031 EE Portfolio Plan and associated annual budgets. First, Senate Bill ("SB") 350 (De León, 2015) requires that the state double its EE

²² D.23-06-055.

²³ *Id.*, pp. 26-37.

²⁴ *Id.*, pp. 37-42.

²⁵ *Id.*, pp. 52-54, 57-59, and 61-65.

²⁶ *See, e.g., id.*, p. 89, Conclusion of Law ("COL") 46.

savings by 2030. Accordingly, MCE proposes to expand its EE programming, as described in more detail in Exhibit 1, Chapter 4, Section 4 of MCE’s testimony.

Another key consideration that informed all aspects of MCE’s Application is the ongoing and worsening energy affordability crisis in California. In September 2024, Assembly Bill (“AB”) 3264 directed the Commission to analyze a variety of relevant metrics to “identify evidence-based approaches to mitigating, reducing, and managing” residential electric rates in response to rising electricity prices.²⁷ The next month, Executive Order (“E.O.”) N-5-24 instructed the Commission to (1) examine the “benefits and costs to electric ratepayers of programs it oversees and rules and orders it has promulgated” that may be “unduly adding to electric rates, or whose funding might more appropriately come from a source other than ratepayers,” and (2) “take immediate action” to “modify or sunset any underperforming or underutilized programs or orders whose cost exceed the value and benefits to electric ratepayers.”²⁸ In this Application, MCE documents the analysis and metrics it is using to ensure that its EE offerings meet the Commission’s relevant cost-effectiveness goals. MCE’s commitment to affordability goals is also reflected in its proposal for a 19 percent reduction in its EE budget for years 2028-2031, as compared to that initially approved by the Commission in D.23-06-055.

Finally, MCE’s policy proposals in this Application are also geared toward addressing affordability concerns in the context of the state’s EE programming—both in terms of ensuring ratepayer funds are used in the most efficient and effective manner, and in terms of expanding access to the benefits of EE to more Equity customers. MCE is asking that the Commission adopt a policy that excludes participant costs from cost-effectiveness tests (to enable MCE to stretch

²⁷ AB 3264 (Petrie-Norris), sec. 1(b), 3(b).

²⁸ State of California, Executive Department, E.O. N-5-24 (Oct. 30, 2024).

ratepayer funds further), and adopt a flexible budget cap for MCE’s Equity programs (to enable MCE to spend more of its budget assisting those customers who are most strained by the high energy burdens facing California residents).

IV. THE COMMISSION SHOULD APPROVE MCE’S APPLICATION

MCE requests Commission approval of its 2028-2031 EE Portfolio Plan and its 2032-2035 EE Business Plan. MCE also requests that the Commission adopt several policy recommendations related to EE program and portfolio development.

A. The Commission Should Approve MCE’s 2028-2031 Energy Efficiency Portfolio Plan, Including MCE’s Proposed Annual Budgets.

MCE does not propose to make wholesale changes to its portfolio during the 2028-2031 Portfolio Plan period. Instead, MCE will fine-tune its existing portfolio—building on lessons learned from administering successful, locally led EE programs since 2013—and incorporate innovations that meet new policy goals. The sections below explain how MCE’s proposed 2028-2031 EE Portfolio Plan will benefit not only customers in MCE’s service area but also all California ratepayers.

1. MCE’s Proposed Energy Efficiency Portfolio Plan and Annual Budgets are Reasonable.

MCE’s 2028-2031 Portfolio Plan is reasonable because it includes a balanced set of program offerings that comprehensively address the needs of its agricultural, commercial, industrial, public, and residential customers. Over the four-year Portfolio Plan period, MCE will implement cost-effective EE (and demand management) programs, while also supporting the sustained growth of the EE market in its service area and ensuring that all customers enjoy the benefits of EE, especially those historically underserved by EE programs. MCE’s budget for PY 2028-2031 is lower than that originally approved in the 2024-2031 Business Plan, reducing the impact of this program on ratepayers to the extent appropriate based on MCE’s assessment of the

opportunities to accomplish EE program goals in its territory. MCE refined its EE portfolio to better ensure prudent and cost-effective program administration.

MCE’s customer base, which spans four Bay Area counties, is unique and diverse. While residential customers are the most prominent group among MCE’s customer accounts, MCE also serves commercial, agricultural, public, and industrial customers. A significant proportion of customers in MCE’s service area were born outside the United States, and nearly one-third of MCE’s population base speaks a language other than English at home. Household incomes in MCE’s service area vary widely—whereas household incomes are higher in Marin and Contra Costa counties, incomes are comparatively lower in Napa and Solano counties.

MCE’s unique service area and customer base require MCE to employ a diverse set of strategies in order to successfully deliver the portfolio outcomes it strives to achieve. MCE’s overarching portfolio strategies are to: (1) maximize Total System Benefits (“TSB”); (2) implement meaningful Equity programs; (3) support electrification and decarbonization efforts; (4) incorporate load shaping and demand response (“DR”); and (5) optimize delivery channels. MCE’s portfolio—including its proposed annual budgets and goals—is reasonably designed to implement those strategies. **Tables 1** and **2** below summarize MCE’s budget and goals on an annual basis during the 2028-2031 portfolio period.²⁹

²⁹ The difference between the total and the sum of each year is due to rounding.

Table 1: 4-Year Portfolio Budget Forecast Summary (2028-2031)

4-Year Portfolio Budget Forecast Summary (2028-2031) (\$000)					
	2028	2029	2030	2031	Total (4 Years)
Total Budget	\$15,577	\$16,454	\$16,556	\$16,664	\$65,251
Resource Acquisition Segment Budget	\$9,502	\$10,037	\$10,099	\$10,165	\$39,803
Market Support Segment Budget	\$765	\$808	\$813	\$818	\$3,203
Equity Segment Budget	\$4,687	\$4,951	\$4,982	\$5,014	\$19,635
Codes and Standard Budget	\$0	\$0	\$0	\$0	\$0
EM&V	\$623	\$658	\$662	\$667	\$2,610
Administration	\$1,020	\$1,460	\$1,499	\$1,539	\$5,518
ED Portfolio Oversight	\$0	\$0	\$0	\$0	\$0

Table 2: 4-Year Portfolio Forecast Summary (2028-2031)

4-Year Portfolio Forecast Summary (2028-2031) (\$000)						
	2028	2029	2030	2031	Resource Acquisition Segment Only (Total 4-Year)	Total (4 Years)
Total System Benefit (“TSB”)	\$16,737	\$17,452	\$18,224	\$19,012	\$58,392	\$71,426
Total Resource Cost (“TRC”) Ratio	0.98	0.97	1.00	1.03	1.23	1.00
Program Administrator Cost (“PAC”) Ratio	1.07	1.06	1.10	1.13	1.43	1.09
Societal Cost Test (“SCT”) Base	1.30	1.29	1.33	1.37	1.59	1.35
SCT High	1.30	1.29	1.33	1.37	1.60	1.35
Ratepayer Impact Measure Test Ratio (“RIM”)	0.58	0.58	0.59	0.59	0.71	0.58
Lifecycle GWh³⁰	27	27	27	27	192	109
First Year MW	1,467	1,467	1,467	1,467	5,553	5,868
Lifecycle MMTherms	7	7	7	7	16	26.3
Lifecycle CO2 Metric Tons	4,739	4,044	3,952	3,931	14,577	16,666

MCE’s annual Portfolio Plan budget is reasonable because it reflects a “zero-based” budgeting approach. The zero-based budgeting approach requires MCE to justify all expenses for each year of the four-year period after analyzing each function within the budget for its needs and costs.³¹ To develop a zero-based budget, MCE considered the following factors in turn: (1)

³⁰ Resource Acquisition Segment GWh savings exceed Total (4 Years) GWh savings due to the high volume of electrification measures forecasted within the Equity segment.

³¹ D.21-05-031, OP 8.

regulatory and statutory requirements and legislative guidance; (2) MCE’s mission and vision; (3) analysis of program performance during the current cycle; (4) assessment of emerging opportunities; and (5) analysis of other cost drivers, including staffing, implementation contracts, and incentive costs.

Decision 21-05-031 contains the key regulatory requirements relevant to MCE’s portfolio budget. Specifically, D.21-05-031 requires that PAs limit the expenditures on Market Support and Equity programs, combined, to a total of no more than 30 percent of their total portfolio budget.³² MCE applied this requirement when developing the budget for the portfolio period (PYs 2028 to 2031), in which the Market Support and Equity segments make up 30 percent of MCE’s EE portfolio.³³ However, MCE is also recommending that the Commission adopt a flexible limit on the budget cap for MCE’s Market Support and Equity segments (based on population percentages in MCE’s service area). Therefore, MCE has also provided an alternate budget that dedicates 35 percent of its portfolio period budget to these segments (30 percent Equity and five percent Market Support). MCE’s portfolio budget is further informed by SB 350 (De León, 2015) and AB 3264 (Petrie-Norris, 2024), which respectively require a doubling of EE by 2030 and the identification of “evidence-based approaches to mitigating, reducing, and managing” residential electric rates in response to rising electricity prices.³⁴

MCE’s mission and vision, which emphasize EE, also inform its budget. MCE’s EE programs are central to achieving its mission by (1) reducing load and making it easier to meet renewable energy targets; (2) supporting the local economy and advancing Equity goals through

³² D.21-05-031, OP 4.

³³ *See Exhibit 1, Chapter 6, Sections 2.*

³⁴ AB 3264 (Petrie-Norris), sec. 1(b), 3(b).

Equity programming; and (3) supporting the local workforce through a Workforce Education & Training (“WE&T”) program. As such, MCE’s budget reflects an effort to invest as much as possible in EE while following the rules and regulations for ratepayer-funded EE programs established by the Commission.

MCE completed its zero-based budgeting exercise by assessing the activities associated with its existing EE portfolio, identifying emerging opportunities for EE deployment, and analyzing key cost drivers. To identify emerging opportunities, MCE analyzed several sources including the 2025 Potential and Goals (“P&G”) study³⁵ and the 2024 Avoided Cost Calculator (“ACC”). MCE’s analysis of cost drivers included an examination of staffing and operational costs, implementation costs, marketing costs, and incentives. MCE describes its assessment and analysis of cost drivers, and their impacts on PY 2028-2031 budgets, in Exhibit 1, Chapter 4 of its testimony.

2. *MCE’s Proposed Energy Efficiency Portfolio is Reasonably Designed to Meet the Goals of its Resource Acquisition, Market Support, and Equity Segments.*

Consistent with the Commission’s directives in D.21-05-031,³⁶ MCE has divided its portfolio into Resource Acquisition, Market Support, and Equity segments (described in more detail in Exhibit 1, Chapters 3 and 6 of MCE’s testimony). MCE’s portfolio of programs is reasonably designed to meet the goals of each of these segments.

MCE’s Resource Acquisition segment includes programs that will deliver cost-effective avoided cost benefits to the electricity and natural gas systems. MCE designed these programs to

³⁵ See Cal. Pub. Util. Comm’n, 2025 Energy Efficiency Potential and Goals Study – Final, *available at*: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2025-potential-goals-study/2025-group-e-potential--goals-study-final-report-20250717.pdf>.

³⁶ D.21-05-031, OP 2.

maximize TSB while mitigating ratepayer risk and providing value to MCE’s customers. MCE’s Resource Acquisition programs are a combination of existing and new programs. MCE’s existing programs include both established programs (*e.g.*, Flex Market and Strategic Energy Management) and recently launched and approved programs (*e.g.*, Multi-Family Energy Savings-Resource (“MFES-R”) and IDSM). MCE is also proposing two new Resource Acquisition programs. First, MCE’s Home Energy Savings-Resource program will build on strategies that MCE successfully developed in its Equity segment (as was the case for the MFES-R program). Second, MCE is launching a program to accelerate refrigerant replacement in its territory (Low Global Warming Potential Refrigerant Accelerator Program). MCE’s Resource Acquisition segment has a forecasted TRC ratio of 1.23 over the Portfolio Plan period, which exceeds the Commission’s *ex-ante* cost-effectiveness requirement (*i.e.*, a TRC ratio of 1.0).³⁷

MCE’s Equity segment includes programs with a primary purpose of providing EE to Equity customers in advancement of the Commission’s Environmental and Social Justice (“ESJ”) Action Plan.³⁸ The programs are designed to (1) address disparities in access to EE programs; (2) deliver non-energy benefits (“NEBs”); (3) reduce energy-related greenhouse gas and criteria pollutant emissions; and (4) provide workplace opportunities. MCE’s Equity programs cover the residential and commercial sectors, including the Home Energy Savings-Equity program, the Multi-Family Energy Savings-Equity program, and the SBEA program. MCE’s Equity programs offer (1) additional technical support; (2) reduced or no customer copays; (3) meaningful community engagement; and (4) targeted communications to eligible customers. They are geared

³⁷ D.21-05-031, OP 3.

³⁸ See Cal. Pub. Util. Comm’n, Environmental & Social Justice Action Plan; Version 2.0 (Apr. 7, 2022), available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/esj-action-plan-v2jw.pdf> (“ESJ Action Plan”).

toward customers that would otherwise be challenging to serve under the cost-effectiveness requirements applicable to the Resource Acquisition segment. Improving access to EE for Equity customers achieves energy savings and can also provide extremely valuable NEBs, such as (1) increased resiliency, health, comfort, and safety; (2) improved indoor air quality; and (3) more affordable utility bills and energy savings. These NEBs are consistent with Goals 1, 2, 5, and 7 in the Commission’s ESJ Action Plan.³⁹

MCE’s Market Support segment consists of a single program, the WE&T program, which is tailored to support a workforce that can install advanced EE and electrification measures. This program does not claim savings but instead supports other programs that incentivize building electrification by increasing the available contractor pool. As a part of this program, MCE will provide training for EE contractors and jobseekers in the sustainable energy field; match jobseekers with energy contractors for paid, on-the-job training; and follow best practices from industry leaders in creating high-quality employment. The WE&T program pursues each of the sub-objectives of the Market Support segment (*i.e.*, Demand, Supply, Partnerships, Innovation and Accessibility, and Access to Capital).

Table 1 (above) summarizes MCE’s requested budget on an annual basis, disaggregated by segment, during the 2028-2031 Portfolio Plan period.

3. *MCE’s Portfolio Includes Robust Programs in the Agricultural, Commercial, Cross-Cutting, Industrial, and Residential Sectors.*

Over the Portfolio Plan period, MCE will continue to offer programs in the agricultural, commercial, industrial, and residential sectors, as well as a cross-cutting WE&T program. MCE emphasizes its residential and commercial sector programming because the residential sector

³⁹ See ESJ Action Plan at 6-8.

makes up the highest number of MCE customer accounts (nearly 90 percent) while the commercial sector provides the greatest opportunities for achieving cost-effective savings.

MCE will deploy certain strategies that are common to all of its sectors. For instance, across all sectors, MCE will (1) scale TSB and implement pay-for-performance programs to align incentives; (2) identify customers with the greatest savings and TSB potential using MCE's Data Analytics Platform;⁴⁰ and (3) support streamlined customer enrollment in other complementary programs (referred to as the "Any Open Door" strategy), which leverages EE as an opportunity to promote complementary affordability, sustainability and energy offerings.

With respect to the residential sector, MCE proposes two primary goals: (1) serve low- to moderate-income customers with comprehensive offerings that save energy and produce bill savings while providing additional NEBs like improved health, safety, and comfort; and (2) serve market-rate residential customers with programs that meet or exceed TSB requirements. To meet its residential customers' needs, MCE will deploy the above common strategies as well as several strategies unique to this segment, namely: (1) expand existing programs to reach moderate-income customers, and (2) invest in community engagement.

With respect to the commercial sector, MCE proposes to supplement the common strategies with the following tailored strategies to meet its portfolio goals. MCE will (1) efficiently implement commercial programs within the overarching MCE Energy Management Program umbrella; (2) deploy Strategic Energy Management ("SEM") and custom projects with measures designed to meet commercial customers' unique business needs; (3) incorporate low global warming potential equipment installations; and (4) assist customers to access and enroll in creative

⁴⁰ MCE is committed to offering EE programs to all its customers, complying with all applicable data privacy laws, ensuring equitable access to its programs, and following Commission requirements for program administration. MCE's use of its data analytics tool is rooted in those core principles.

financing opportunities offered by other entities.⁴¹

MCE's unique strategies for the industrial sector include (1) holistic program design and implementation that cost-effectively addresses the needs of industrial customers (MCE's Energy Management program) and mitigates common customer pain points; and (2) deploying SEM and custom projects with measures designed to meet industrial customers' unique business needs.

For the smaller, challenging-to-serve agricultural sector, MCE will (1) efficiently implement agricultural programs within the overarching MCE Energy Management Program umbrella; (2) deploy EE projects with measures designed to meet agricultural customers' unique business needs; and (3) market program benefits by engaging with local agricultural partner organizations (*e.g.*, county farm bureaus).

Finally, MCE's cross-cutting WE&T program will increase the capacity of the workforce to install and maintain emerging EE and electrification measures and create opportunities for sustainable employment in the building electrification industry. The WE&T program is MCE's only program in the Market Support segment, and MCE's strategies for achieving its Market Support segment's goals are further described above.

Through these sector-specific strategies, which are described in more detail in Exhibit 1, Chapters 3 and 6 of MCE's testimony, MCE's portfolio will comprehensively address the needs of its agricultural, industrial, commercial, and residential customers. MCE will also continue to serve public sector customers through its existing EE programs depending on their specific characteristics and energy usage patterns. For example, MCE will continue to engage with public water and wastewater agencies under its industrial program.

⁴¹ MCE defines "Commercial Equity customers" for the purposes of this Application as businesses in ESJ communities. *See Exhibit 1, Chapter 3, Section 11.5; Chapter 6, Section 5.5.*

Table 3 below summarizes MCE’s requested budget on an annual basis, disaggregated by sector, during the 2028-2031 portfolio period.⁴²

Table 3: Budget Distribution by Sector

Budget Distribution by Sector (\$000)									
	Sector								
Budget	Residential	Commercial	Industrial	Agricultural	Public	Cross-Cutting	EM&V	Portfolio Support	Total Budget
2028	\$5,007	\$5,460	\$1,910	\$100	\$0	\$1,674	\$623	\$803	\$15,577
2029	\$5,289	\$5,823	\$2,018	\$106	\$0	\$1,712	\$658	\$848	\$16,454
2030	\$5,322	\$5,866	\$2,031	\$106	\$0	\$1716	\$662	\$853	\$16,556
2031	\$5,356	\$5,910	\$2,044	\$107	\$0	\$1721	\$667	\$859	\$16,664
Total (4-year)	\$20,974	\$23,059	\$8,003	\$419	\$0	\$6,823	\$2,610	\$3,363	\$65,251
2032	\$5,393	\$5,880	\$2,058	\$108	\$0	\$1,803	\$671	\$865	\$16,777
2033	\$5,431	\$5,922	\$2,072	\$108	\$0	\$1,816	\$676	\$871	\$16,896
2034	\$5,471	\$5,966	\$2,088	\$109	\$0	\$1,829	\$681	\$877	\$17,021
2035	\$5,513	\$6,012	\$2,104	\$110	\$0	\$1,843	\$686	\$884	\$17,151
Total (4-year)	\$21,808	\$23,779	\$8,321	\$436	\$0	\$7,290	\$2,714	\$3,497	\$67,845
Cumulative Total (8-Year)	\$42,782	\$46,838	\$16,324	\$854	\$0	\$14,113	\$5,324	\$6,860	\$133,096

4. MCE has Demonstrated Successful EE Program Administration During the Current Portfolio Period and Plans to Build on This Success in the Next Portfolio Period.

As noted above, MCE has been serving as an EE PA for over a decade. MCE has participated in numerous Commission-created working groups, developed deep and sustained relationships with stakeholders and community members, and has a documented history of successfully identifying, launching, managing, evaluating, and scaling EE programs in a challenging and changing service area.

To date, MCE EE programs have achieved the following notable impacts:

- **Energy Savings:**
 - 32,422,101 gross kWh; and

⁴² The difference between the total and the sum of each sector is due to rounding.

- 1,674,116 gross therms.⁴³
- **Multifamily Energy Savings-Equity program:**⁴⁴ Served 5,124 low-income (deed-restricted) multifamily units upgraded with direct install EE measures. Of those, 528 received electrification upgrades producing 1.4M kWh and 108,000 therms of energy savings.⁴⁵
- **Home Energy Savings-Equity program:**⁴⁶ Served 2,105 low- and moderate-income single-family homes with direct install EE and electrification measures producing 500,000 kWh and 7,000 therms of energy savings.⁴⁷
- **Flex Market programs (Commercial and Residential):**
 - **Commercial:** 103 commercial EE projects completed in PYs 2021-2024 and 49 approved for installation in PY 2025 producing 8,650,000 kWh in energy savings.⁴⁸
 - **Residential:** 54 residential heat pump water heater projects approved for installation in PY 2025.⁴⁹
- **Green Workforce Pathways program (“GWPP”):** Served 287

⁴³ MCE EE programs 2013 – 2025.

⁴⁴ Now the Multifamily Energy Savings-Equity program following approval of AL 91-E (approving launch of Multifamily Energy Savings-Resource program).

⁴⁵ Program established in 2013.

⁴⁶ Formerly the Home Energy Savings program prior to this Application.

⁴⁷ Program established in 2019.

⁴⁸ Program established in 2021.

⁴⁹ Program established in 2025.

participating contractors and job seekers.⁵⁰

During the portfolio’s 2024-2027 program years MCE also launched three new programs serving its Equity and Resource Acquisition segments and residential and commercial customers.⁵¹ One of these programs, the SBEA Equity segment program, has served 180 small businesses, with each business saving an estimated average of \$450/year on their utility bills. Each business served qualifies as an Equity customer,⁵² with 30 percent located in a Disadvantaged Community (“DAC”), 80 percent located in a Low-income census tract, and 74 percent meeting the criteria of Hard-to-Reach (“HTR”). SBEA has conducted four city-wide door-to-door campaigns in partnership with local Community Based Organizations (“CBOs”) and Green Business Programs (“GBPs”) with the aim of increasing access to program resources for Equity participants.

In addition to delivering these customer benefits through its EE programming, MCE has also invested in research and thought leadership in the EE space. MCE recently published an equitable residential electrification study⁵³ and is finalizing another study analyzing municipal permitting processes. Both studies have and will produce learnings that will benefit customers statewide.

MCE’s track record demonstrates it provides a strong, interconnected web of EE program offerings that operate to meaningfully increase the level of EE in MCE’s territory and statewide, while ensuring disadvantaged and HTR customers’ specific needs are appropriately prioritized.

⁵⁰ Program established in 2019.

⁵¹ Small Business Energy Advantage, Multifamily Energy Savings-Resource, and Integrated Demand Side Management program. **See Exhibit 1, Chapter 4, Section 4.2.**

⁵² MCE defines “Equity Customer” for the purposes of this Application as all categories of customers eligible for its proposed Equity segment programs in **Exhibit 1, Chapter 6, Section 5.1.**

⁵³ MCE Equitable Electrification: Final Report (Jan. 30, 2026), available at <https://pda.energydataweb.com/api/view/4275/Equitable%20Electrification%20Final%20Report%2001.30.26.pdf>.

B. The Commission Should Approve MCE’s Proposed 2032-2035 Energy Efficiency Business Plan, Including its Proposed Budget Cap.

MCE’s 2031-2035 Business Plan provides the long-term strategic overlay to MCE’s near-term Portfolio Plan strategies, expected outcomes, and budgets, as described above.⁵⁴ As such, the eight-year Business Plan is an extension of the four-year Portfolio Plan. Importantly, MCE has intentionally designed its Business Plan such that it is philosophically consistent with the Portfolio Plan.

Over the eight-year Business Plan period, MCE will continue to (1) aim to maximize TSB through the implementation of cost-effective EE programs; (2) support the sustained growth of the EE market in its service area; (3) foster the closer integration of EE and demand management strategies; and (4) ensure that all customers enjoy the benefits of EE, especially those historically underserved by EE programming. **Tables 4** and **5** below summarize MCE’s requested budget, TSB goals, and energy savings targets on an annual basis during the 2032-2035 Business Plan period.

Table 4: 4-Year Portfolio Budget Forecast Summary (2032-2035)

4-Year Portfolio Budget Forecast Summary (2028-2031) (\$000)					
	2032	2033	2034	2035	Total (4 Years)
Total Budget	\$16,777	\$16,896	\$17,021	\$17,151	\$67,845
Resource Acquisition Segment Budget	\$10,234	\$10,306	\$10,383	\$10,462	\$41,385
Market Support Segment Budget	\$824	\$829	\$835	\$842	\$3,330
Equity Segment Budget	\$5,048	\$5,084	\$5,122	\$5,161	\$20,415
Codes and Standard Budget	\$0	\$0	\$0	\$0	\$0
EM&V	\$671	\$676	\$681	\$686	\$2,714
Administration	\$1,585	\$1,633	\$1,682	\$1,732	\$6,632
ED Portfolio Oversight	\$0	\$0	\$0	\$0	\$0

⁵⁴ As noted *supra* in note 1, MCE is providing a business plan for PYs 2032-2035 in reliance on Energy Division staff instructions (verbal, email, and through the provided Application Template) to use these four years as opposed to 2028-2035 as the years for the Business Plan. *But see* D.21-05-031, at OP 5 (contemplating an eight-year business plan).

Table 5: 4-Year and 8-Year Total System Benefit Forecast (w/out C&S) vs. Goals

<i>4-Year and 8-Year Total System Benefit Forecast vs. Goals (\$000)</i>			
Year	Total System Benefit Forecast	Total System Benefit Goals	Percent of TSB Goal
2028	\$16,737	\$16,737	100%
2029	\$17,452	\$17,452	100%
2030	\$18,224	\$18,224	100%
2031	\$19,012	\$19,012	100%
Total (4 years)	\$71,426	\$71,426	100%
2032	\$19,818	\$19,818	100%
2033	\$20,642	\$20,642	100%
2034	\$21,542	\$21,542	100%
2035	\$22,413	\$22,413	100%
Total (4 years)	\$84,416	\$84,416	100%
Cumulative (8 years)	\$155,842	\$155,842	100%

MCE’s Business Plan and associated budgets are reasonable because they are an extension of the strategies in its four-year Portfolio Plan and because they anticipate continued evolution in California’s energy goals. As California’s energy goals evolve, new market and technology opportunities emerge, and the Commission institutes new demand-side management policies and directives, MCE will continue to innovate and diversify its program offerings. MCE expects that over the Business Plan period: (1) its meter-based and pay-for-performance programs will continue to grow; (2) electrification programs will become a more prominent feature of its portfolio; (3) decarbonization will play an increasingly important role in portfolio planning; (4) EE programs will be more closely integrated with other demand-side management offerings to support improved grid reliability; and (5) a focus on affordability will anchor portfolio planning and implementation decisions. Consistent with D.21-05-31, MCE will file a Portfolio Plan application for PYs 2032-2035 in which it will detail its program strategies for that future period in more detail.

C. Recommendations for New, Modified, or Clarified Energy Efficiency Policies

MCE includes its recommendations for new or modified EE policies in Exhibit 1, Chapter 11 of its testimony, and summarizes those recommendations briefly below.

1. *The Commission Should Exclude Participant Costs from Cost-Effectiveness Tests.*

The Commission uses a variety of cost-effectiveness tests and other relevant metrics to evaluate the performance of EE portfolios.⁵⁵ Importantly, the definition of cost-effectiveness is within the Commission’s discretion and naturally must evolve over time. As the Commission has explained, “the definition of cost-effectiveness has always been left to interpretation and implementation by the Commission, and though past decisions are interesting, they do not prevent the Commission from evolving its definition of cost-effectiveness, from time to time, as strategies evolve or as market conditions warrant.”⁵⁶

MCE recommends the Commission update its cost-effectiveness tests to exclude participant costs, to ensure ratepayer funds are put to their highest and best uses in response to California’s electric affordability crisis.⁵⁷ E.O. N-5-24 specifically requested the Commission evaluate the costs and benefits of electric ratepayer funded programs with an emphasis on their impacts to electric rates. Similarly, in 2024, the state legislature passed AB 3264 in response to rising energy costs and directed the Commission to analyze a variety of relevant metrics to “identify evidence-based approaches to mitigating, reducing, and managing” residential electric

⁵⁵ D.21-05-031, pp. 18-24.

⁵⁶ *Id.*, p. 67.

⁵⁷ Sierra Club, California’s Affordability Crisis: Utilities Asking for More Money for Shareholders, November 2025, available at: <https://www.sierraclub.org/articles/2025/11/california-s-affordability-crisis-utilities-asking-more-money-shareholders>.

rates.⁵⁸ In line with these directives, the Commission should adopt policies that ensure PAs maximize the benefit from all EE-dedicated ratepayer funds, and spread the benefits from these funds as far as possible while still achieving core program goals.

Removing participant costs from the calculation of the EE program cost-effectiveness tests would be an important step toward this end. The presence of participant costs in EE cost-effectiveness tests unnecessarily dilutes the accuracy and required oversight of ratepayer funds used in portfolios. Participant costs, by definition, are not ratepayer funds and are instead the personal, out-of-pocket expenses paid by a participating customer.⁵⁹ In light of the ongoing energy affordability crisis and recent corresponding policy directives, the Commission should take its next step in evolving its cost-effectiveness analysis and exclude participant costs from EE portfolio cost-effectiveness tests.

2. *The Commission Should Allow CCA PAs to Adjust Equity Segment Budget Caps in Support of Greater Energy Affordability and Energy Equity.*

The Commission requires PAs⁶⁰ to limit their Market Support and Equity segment programs to 30 percent of their total portfolio budgets.⁶¹ In creating the Market Support and Equity segments, the Commission prudently recognized that cost-effectiveness requirements were preventing the needed investments in Equity and Market Support focused activities and programs.⁶²

⁵⁸ AB 3264 (Petrie-Norris), sec. 1(b), 3(b).

⁵⁹ CPUC, Energy Efficiency Policy Manual Version 6, April 2020, *available at*: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/eepolicymanualrevised-march-20-2020-b.pdf>, at 25-26.

⁶⁰ Excluding RENs.

⁶¹ D.21-05-031, p. 23; D.23-06-055, p. 13.

⁶² D.21-05-031, pp. 13-14.

In 2021, the Commission based its adoption of a 30 percent budget cap for Market Support and Equity segments on its historic funding determinations for previous EE portfolios.⁶³ The Commission analyzed the then-current program expenditures of 20 percent non-resource program spending at that time and stated that increasing the non-resource budget to 30 percent was reasonable.⁶⁴ The segmentation scheme was brand new at that time and, absent any other competing proposals, basing the budgets on historic spending made sense.

However, we have five years of experience since 2021, and California is presently experiencing an energy affordability crisis which disproportionately and severely impacts low-income and DAC customers.⁶⁵ The EE portfolios are an important tool the Commission should utilize to better support energy affordability for those most unable to bear this increasing burden.

The Commission should therefore strategically relax current limits on this tool by allowing CCA PAs to adjust their Equity segment budget caps to a level that is more proportional to the demographics of their customer base, and specifically, to the percentage of their customers that are Equity customers. This proportional funding approach for Equity customers is common in other California climate and energy investment programs.⁶⁶ MCE's customer base is approximately 41 percent Equity customers, and as such MCE believes it is reasonable to spend up to 35 percent of its portfolio budget on Equity and Market Support segment (30 percent Equity;

⁶³ *Id.*, p. 23 (“Based on a review of the budgets approved by the Commission on similar program types in the past, beginning with this decision we will limit the funds that may be spent on market support and equity programs to 30 percent of the overall budget of each program administrator, with the exception of the RENs.”).

⁶⁴ *Ibid.*

⁶⁵ AB 3264 (Petrie-Norris), 2024, sec. 1(a)(2); 4.

⁶⁶ *See, e.g.*, Greenhouse Gas Reduction Fund and Electric Program Investment Charge. For example, SB 535 (De León 2012), AB 1550 (Gomez 2016), and AB 523 (Reyes 2018) all require 25 percent allocation of climate and energy funds to the 25 percent of the state's population living in DACs. SB 535 (De León 2012) Section 3(a), AB 1550 (Gomez 2016) Section 1(a), and AB 523 (Reyes 2018) Section 1(b).

five percent Market Support) programs. The Commission should not artificially restrict the ability of CCA PAs like MCE to serve the unique needs and characteristics of their service area by limiting Equity and Market Support segment budgets to 30 percent regardless of the percent of the PA's customer base that falls within the Equity designation.

3. *The Commission Must Clarify its Application of the Equity and Market Support Segment Budget Cap.*

PAs design, execute, and reevaluate their EE program offerings based on the four-year budgets the Commission approves and any limitations the Commission places on the use of those budgets. For example, for the 2024-2027 portfolio period, the Commission limited expenditures on Equity and Market Support across EE programs with a 30 percent total portfolio budget cap.

PAs operate a vast array of different kinds of programs, and not all programs that PAs operate draw down their budgets at the same rate. Tracking progress through ALs and check-ins with Energy Division is important, but PAs should not have their overall budgets reduced if their outlays do not precisely hit budget caps (that were meant for the full portfolio period) at numerous midpoints. If that were the case, once early-year actuals are realized, they would permanently affect the spending ratio, and it would be impossible to correct them through subsequent implementation. This would operate as a rolling proportional constraint tied to realized spending and would cease to serve as a cap evaluated against the Commission-authorized budget over the full four-year period.

This hybrid framework—combining cumulative actual expenditures with forward-looking forecasts—leads to unreasonable administrative burdens and policy distortions. In practice it effectively requires PAs to maintain proportional spending across portfolio segments throughout the portfolio period. For the Equity and Market Support budget cap, this means ensuring that, for every dollar spent outside these segments, a corresponding share of spending is reflected within

those segments, regardless of implementation timing, contract structures, or market conditions.

Recent experience highlights the need for policy clarification regarding how these kinds of budget caps are applied mid-cycle, particularly when prior-year actuals and voluntary budget adjustments are used in ways that redefine the cap itself.⁶⁷ The Commission adopted a four-year portfolio budget period for a reason. The Commission did not adopt a hybrid budgeting approach that mixes expenditures and forecasts, and it should clarify that it will not apply this hybrid framework analysis for the remainder of the 2024-2027 portfolio period or the 2028-2031 portfolio period.

While analyzing TSB (and other performance-based targets) using this kind of hybrid analysis is appropriate, budgets are not amenable to this kind of analysis. Applying a hybrid trajectory framework designed for performance goals to authorization-based budget caps conflates two fundamentally different regulatory constructs and effectively transforms a fixed cap into a rolling proportional spending requirement—an outcome neither articulated in Commission decisions nor aligned with the purpose of budget authorization.

MCE therefore respectfully requests that the Commission:

1. Clarify that the combined Equity and Market Support budget cap is calculated as a percentage of the Commission-authorized total portfolio budget approved in the EE application decision, and that this denominator remains fixed for the four-year portfolio period absent explicit Commission action.
2. Confirm that cumulative actual expenditures are used to measure progress toward the

⁶⁷ Energy Division recently required MCE to reduce its *budget* as part of the MCAL review. At the time of the MCAL filing, MCE's Equity and Market Support budgets remained within the dollar caps originally approved by the Commission in both the EE application decision and the 2023 True-Up Advice Letter (TUAL).

authorized cap but do not redefine or re-baseline the authorized budget base.

3. Affirm that the Mid-Cycle Advice Letter (“MCAL”) serves as the final forward-looking checkpoint for assessing cap compliance trajectory (unless the below trigger applies) and does not establish a new cap or denominator.
4. Direct PAs to include a standardized Equity and Market Support Cap Tracking Table in annual reports following MCAL approval to support transparent, prospective oversight.
5. Establish a trigger-based enforcement mechanism requiring prospective corrective action, including a Tier 2 AL where appropriate, only if an annual report demonstrates a reasonable risk of exceeding the authorized cap.
6. Clarify that while hybrid actuals-plus-forecast evaluation is appropriate for TSB goals, budget caps are authorization-based constraints and should be evaluated based on cumulative expenditures relative to Commission-authorized limits.

4. *The Commission Should Streamline and Update the Definition of an Energy Efficiency Program.*

MCE recommends the Commission update its definition of an EE program in its public reporting to improve portfolio transparency and customer access to program information. While the California Energy Data and Reporting System (“CEDARS”) is a tremendous tool that provides significant information to the public, MCE has received feedback from other stakeholders interested in EE programs that its interface and organization can be difficult to navigate.

One difficulty consistently identified by stakeholders is the sheer number of EE programs and metrics. On CEDARS, reports are organized by individual PA and on a programmatic basis with specific program identifications (“IDs”). The present organization of programmatic information is very detailed, but it can also be overwhelming and make it challenging to understand the larger trends of portfolio performance or program offerings. MCE recommends the

Commission update its definition of an EE program on the CEDARS website, prioritize aggregating data, and present streamlined trends of portfolio performance.

To reduce customer confusion, MCE recommends the Commission adopt an approach for CEDARS similar to the “Switch Is On” website.⁶⁸ MCE recognizes CEDARS serves additional important goals beyond customer education, so instead of removing existing CEDARS components, MCE recommends the Commission, in partnership with PAs, add an additional customer-focused resource that helps customers easily navigate EE program offerings.

5. *The Commission Should Reform EM&V Requirements to Strengthen Transparency, Clarity, and Administrative Efficiencies.*

MCE recommends the Commission update the Evaluation, Metrics and Verification (“EM&V”) requirements to improve transparency, clarity, and administrative efficiencies. Providing clearer EM&V direction to PAs will support more consistent and timelier compliance in furtherance of related goals.

Currently, the Commission issues EM&V requirements for PAs across several distinct sources including the *2020 Energy Policy Manual*, the *2006 California Energy Efficiency Evaluation Protocols*, and various decisions. These controlling authorities establish the foundational principle that Commission Energy Division Staff oversee EM&V activities and PAs are responsible for supporting evaluations, reviewing findings, and preparing Responses to Recommendations (“RTRs”) when included.

However, PAs do not have a streamlined method or source from which to learn when EM&V studies are published, determine whether specific recommendations apply to their

⁶⁸ The Switch Is On, Modern Electric Appliances Make Happier, Healthier Homes, *available at: <https://www.switchison.org/>*; *See also* Mass Save, Mass Save Data: The Massachusetts Energy Efficiency Database, *available at: <https://www.masssavedata.com/>* (offering streamlined and aggregated EE program reporting for Massachusetts).

portfolios, or to identify due dates for RTR submissions. Absent a single unified EM&V resource, PAs must monitor three distinct repositories.⁶⁹ In the absence of a single, centralized system and PA-specific notifications and indicators, PAs must manually and repeatedly review multiple resources to determine the receipt of a new RTR obligation. This process is time intensive, administratively inefficient, risks PAs missing valuable information, and particularly impacts smaller PAs with comparatively limited staff resources.

MCE recommends the following narrow improvements to reduce duplicative manual effort for all PAs, reduce the necessary staff resources and costs of compliance, remove existing compliance ambiguities, and support timely and accurate RTR submissions:

1. The Commission should issue notifications identifying which EM&V studies require RTRs and their corresponding due dates.
2. The Commission should require PA-specific tags or metadata on the PDA, PSR module, and CalMAC publications indicating which PAs are evaluated in each study.
3. The Commission should issue consolidated guidance and training materials explaining the purpose and application of CalMAC, the PDA, and the PSR module within EM&V requirements.

6. MCE Supports Greater Incorporation of Non-Energy Benefits in Portfolios as More Metrics Become Available.

MCE strongly supports the valuation and consideration of NEBs within the EE portfolios. NEBs like improved health, safety, comfort, resilience, and bill savings are also often the primary motivator for customers' participation in EE programs. As so many Californians are burdened by high energy bills, EE programs should maximize bill savings potential and the NEB of "bill

⁶⁹ The Public Documents Area, the Project Status Reporting Module, and CalMAC.

savings.”⁷⁰ As discussed above, the Governor and legislature directed the Commission to ensure ratepayer programs do everything possible to help energy affordability.⁷¹

Following the publication of the Non-Energy Benefits Study Working Group’s *Non-Energy Benefits Study* in 2026 and any other potentially relevant Non-Energy Impacts publications from the California Energy Commission, the Commission will require PAs to track and report NEBs for the equity segment starting in the Q1 2028 quarterly reports.⁷² There remains an opportunity to incorporate the lessons and recommendations of these publications well before Q1 2028. Since these publications are not presently available, MCE recommends the Commission consider greater incorporation of NEBs with a focus on bill savings prior to 2028 to support energy affordability, Executive Order N-5-24 and AB 3264 compliance, and ESJ Action Plan Goals 2, 4, and 7.⁷³

7. *MCE Strongly Supports IDSM Programs Within the Energy Efficiency Portfolios.*

MCE strongly supports the Commission continuing to fund IDSM programs within the EE portfolios. In D.23-06-055, the Commission authorized “each PA to set aside up to 2.5 percent, or \$4 million, whichever is great[er], of its energy efficiency budget for the portfolio period, up to a maximum of \$15 million, for ongoing load shifting that reduces peak consumption and is not

⁷⁰ Public Policy Institute of California, *Low-Income Households Struggle with the Cost of Electricity Bills*, August 2025, *available at*: <https://www.ppic.org/blog/low-income-households-struggle-with-the-cost-of-electricity-bills/>.

⁷¹ State of California, Executive Department, E.O. N-5-24 (Oct. 30, 2024), *available at*: <https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf>, pp. 1-2; AB 3264 (Petrie-Norris), 2024, sec. 4.

⁷² D.23-06-055, OP 19.

⁷³ CPUC, *ESJ Action Plan Vol 2.*, April 2022, *available at*: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/esj-action-plan-v2jw.pdf> (GOAL 2: Increase Investment in Clean Energy Resources to Benefit ESJ Communities, Especially to Improve Local Air Quality and Public Health; GOAL 4: Increase Climate Resiliency in ESJ Communities; GOAL 7: Promote High Road Career Paths and Economic Opportunity for Residents of ESJ Communities).

event-based” for programs from 2024-2027.⁷⁴ In September 2025, the Commission issued a final resolution approving Pacific Gas & Electric Company (“PG&E”), Southern California Edison Company (“SCE”), Southern California Gas Company (“SoCalGas”), San Francisco Bay Area Regional Energy Network (“BayREN”), Inland Regional Energy Network (“I-REN”), MCE, Southern California Regional Energy Network (“SoCalREN”), and Tri-County Regional Energy Network’s (“3C-REN”) IDSM frameworks and programs.⁷⁵ MCE expects to formally launch its IDSM program in 2026.

In D.23-06-055, the Commission did not explicitly authorize the funding of IDSM frameworks and programs beyond PY 2027.⁷⁶ MCE recommends the Commission continue IDSM funding for PYs 2028-2031 and beyond. The integration of IDSM measures and activities within EE portfolios supports several key policy goals including cost-effectiveness, grid reliability, bill savings, and customer satisfaction in program participation. Evaluations of IDSM programs consistently find the program designs allow the measure of flexibility necessary to produce more valuable energy savings at key times of electric grid stress that simultaneously benefit participant customers and non-participant customers.⁷⁷ As California’s reliability⁷⁸ and affordability⁷⁹ needs

⁷⁴ D.23-06-055, COL 41.

⁷⁵ Resolution E-5387.

⁷⁶ D.23-06-055, COL 41 (“for programs to be launched during 2024-2027”).

⁷⁷ American Council for an Energy-Efficient Economy, ENABLING INDUSTRIAL DEMAND FLEXIBILITY: ALIGNING INDUSTRIAL CONSUMER AND GRID BENEFITS, February 2024, *available at*: https://www.aceee.org/sites/default/files/pdfs/enabling_industrial_demand_flexibility-aligning_industrial_consumer_and_grid_benefits.pdf, p. 5.

⁷⁸ CEC, Staff Report: California Energy Resource and Reliability Outlook, 2025, July 2025, *available at*: <https://www.energy.ca.gov/publications/2025/california-energy-resource-and-reliability-outlook-2025>, p. 108 (“Electricity Demand: California’s electricity demand continues to rise, peaking in summer. The 2024 IEPR Update forecasts a coincident peak of nearly 46,000 MW for the California ISO in summer 2025.”).

⁷⁹ State of California, Executive Department, E.O. N-5-24 (Oct. 30, 2024).

continue to evolve, the Commission should continue investing in the essential tools of IDSM programs integrated within EE portfolios. IDSM programs within EE portfolios further reduce the administrative costs and customer confusion resulting from administering multiple siloed EE, DSM, and demand response programs.⁸⁰ MCE recommends the Commission continue to authorize IDSM funding in EE portfolios for PYs 2028-2031.

V. ORGANIZATION OF MCE'S TESTIMONY

In support of this Application, MCE provides testimony describing its 2028-2031 EE Portfolio Plan and 2032-2035 EE Business Plan in Exhibit 1. This exhibit details MCE's strategic vision, provides annual budgets, and recommends new and modified EE policies for the Commission's consideration. It provides extensive information regarding MCE's portfolio and budget, including, in particular:

- An executive summary of MCE's Portfolio Plan and Business Plan (Chapter 1);
- Portfolio summary (including description of service territory and expected performance metrics) (Chapter 2);
- Portfolio strategy (Chapter 3);
- Forecast methodology and zero-based budgeting (Chapter 4);
- Portfolio management approaches (Chapter 5);
- Segmentation and sector strategy (Chapter 6);
- Portfolio coordination (Chapter 7);
- Stakeholder engagement (Chapter 8);

⁸⁰ Lawrence Berkeley National Lab, Barriers and Opportunities to Broader Adoption of Integrated Demand Side Management at Electric Utilities, February 2018, *available at*: https://eta-publications.lbl.gov/sites/default/files/barriers_and_opps_idsm_final_03222108.pdf, pp. 12, 34.

- Evaluation, measurement and verification (Chapter 9);⁸¹ and
- Policy recommendations (Chapter 11).

Exhibit 2 of MCE’s testimony includes the Program Cards for MCE’s EE programs, and Exhibit 3 contains the CEDARS Filing Links and Receipts.

Consistent with the Commission’s requirements, Exhibit 1 of MCE’s testimony adheres to a template approved by the Commission’s Energy Division. Exhibits 2 and 3 of MCE’s testimony follow the guidance provided by Energy Division staff.

VI. COMPLIANCE WITH THE COMMISSION’S RULES OF PRACTICE AND PROCEDURE

In the sections below, MCE provides certain information regarding its Application, its supporting testimony, and its corporate form in compliance with the Commission’s Rules concerning applications.

A. Summary of Relief Sought - Rule 2.1

MCE respectfully requests that the Commission expeditiously approve this Application and grant the following relief:

- Approve MCE’s 2028-2031 EE Portfolio Plan described in Exhibit 1 of MCE’s testimony, and associated annual budgets described in Exhibit 1, Chapter 2 of MCE’s testimony;
- Approve MCE’s 2032-2035 EE Business Plan described in Exhibit 1 of MCE’s testimony, and associated budget cap described in Exhibit 1, Chapter 2 of MCE’s testimony;
- Exclude participant costs from the cost-effectiveness tests;
- Permit CCA PAs to adjust Equity segment budget caps to better reflect the Equity population of their service area;
- Clarify its application of the Equity segment budget cap;

⁸¹ According to the EE Business Plan Application Template, Chapter 10 is meant to include information regarding cost and cost recovery from IOUs only, and is therefore omitted.

- Streamline and update definitions of an EE program;
- Reform the EM&V requirements to strengthen transparency, clarity, and administrative efficiencies;
- Better include NEBs in portfolios as more metrics become available; and
- Continue to encourage the inclusion of IDSM programs in EE portfolios.

B. Statutory Authority - Rule 2.1

MCE is applying to continue administering EE programs under the authority granted in Cal. Pub. Util. Code § 381.1(a)-(d) and (f), and its obligations to procure EE on behalf of its customers as directed by Cal. Pub. Util. Code § 366.2(a)(5) and § 454.5(b)(9)(C).

C. Legal Name & Principal Place of Business - Rule 2.1(a)

The legal name of the Applicant is Marin Clean Energy. MCE’s principal place of business is San Rafael, California. Its address is 1125 Tamalpais Avenue, San Rafael, CA 94901. MCE is a joint powers authority formed under the laws of California.

D. Correspondence and Communication Regarding this Application - Rule 2.1(b)

MCE consents to email service of all notices, orders, and other correspondence and communications relating to this Application. All correspondence and communications regarding this Application should be addressed to:

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 E-Mail: jgreen@mcecleanenergy.org

E. Categorization - Rule 2.1(c)

The Commission should categorize this Application as a “ratesetting” proceeding under Commission Rule 7.1(e)(2) because it does not clearly fit into any of the categories as defined by

Rules 1.3(a), 1.3(b), 1.3(f), and 1.3(g). MCE’s Application does not meet the definition of adjudicatory in Rule 1.3(a) because it is neither an enforcement investigation nor a complaint. MCE’s Application is not a “catastrophic wildfire proceeding” as defined in Rule 1.3(b) because it does not involve an application to recover costs and expenses related to a wildfire. MCE’s Application does not fit the definition of a “quasi-legislative proceeding” under Rule 1.3(f) because the application does not require the Commission to establish policy or rules affecting a class of regulated entities, and because the Application requests the Commission to grant relief that is specific to MCE. And while MCE’s Application does not ask the Commission to set or investigate rates⁸² and therefore does not meet the definition of a “ratesetting proceeding” in Rule 1.3(g), the Commission should nevertheless categorize this Application as a “ratesetting proceeding” because, as described above, the Commission has the authority to do so where a proceeding does not clearly fit into any of the categories as defined in Rules 1.3(a), (b), (f), and (g).⁸³

F. Need for Hearing - Rule 2.1(c)

MCE has made efforts to provide a sufficient record via its Application materials to obviate the need for evidentiary hearings, and does not recommend hearings at this time. If the need for hearings arises, MCE requests that the resulting hearing schedule allow the Commission to render a final decision on this Application with sufficient time for MCE to start implementing its 2028-2031 Portfolio Plan at the start of 2028. Section VI.H, below, sets forth a proposed schedule for

⁸² EE applications filed by investor-owned utilities are generally categorized as “ratesetting” proceedings under Rule 1.3(g) because those proceedings require the Commission to approve rates that collect the funds necessary to pay for EE programs. In contrast, MCE’s EE Application does not require the Commission to set or investigate rates because, while MCE’s Application has a ratesetting impact, MCE does not itself collect revenue for Commission-authorized EE programs and therefore does not request that the Commission set or investigate rates.

⁸³ Rule 7.1(e)(2).

the consideration of EE applications.

G. Issues to be Considered - Rule 2.1(c)

MCE’s Application requests that the Commission approve MCE’s 2028-2031 Portfolio Plan and its 2032-2035 Business Plan. Approval will enable MCE to successfully and sustainably provide a comprehensive EE portfolio to its member communities.

H. Proposed Schedule - Rule 2.1(c)

MCE proposes the following schedule for the consideration of EE applications:

Application Filed	March 16, 2026
Protests or Responses	April 15, 2026
Replies to Protests or Responses	April 27, 2026
Prehearing Conference	May 18, 2026
Workshops (if needed)	June 22, 2026
Testimony of Interested Parties	July 20, 2026
Rebuttal Testimony/Replies to Comments	August 20, 2026
Evidentiary Hearings (if needed)	September 14, 2026
Opening Briefs	October 19, 2027
Reply Briefs	November 19, 2027
Proposed Decision	February 2027
Final Decision	March 2027

This schedule would satisfy the Commission’s requirement in Rule 2.1(c) that ratesetting proceedings be resolved within 18 months or less.

I. Articles of Incorporation - Rule 2.2

MCE is a CCA operating as a joint powers authority (“JPA”) organized under California law. MCE commenced operations as a JPA on December 19, 2008. MCE is engaged in the provision of electric generation services under the authority granted in Cal. Pub. Util. Code § 366.2 and offers EE programs under the authority granted in Cal. Pub. Util. Code § 381.1. A copy of

MCE's current Amended JPA, amended April 17, 2025, is available on MCE's website.⁸⁴

J. Rule 3.2 Requirement

The requirements listed in Rule 3.2 do not apply to this Application because MCE does not request authority to increase rates or to implement changes that would result in increased rates. IOUs perform revenue collection for MCE's EE programs and typically provide the materials described in Rule 3.2 in their EE applications. As discussed above in Section VI.E (Categorization), MCE does not directly collect revenue for its EE programs. Thus, MCE does not propose specific rate changes in this Application. The requirements of Commission Rule 3.2 therefore cannot reasonably apply to this Application.

K. Notice and Service - Rule 1.9

A copy of the Application and supporting testimony are being served on the parties of record in Rulemaking ("R.") 13-11-005, A.22-02-005 and R.25-04-010, Commissioner Karen Douglas, and Administrative Law Judges Julie A. Fitch and Valerie Kao.

L. List of Supporting Documents

MCE includes several documents to support this Application:

- Testimony of Marin Clean Energy Regarding its 2028-2031 Energy Efficiency Portfolio Plan and 2032-2035 Business Plan (Exhibit 1);
- EE Program Cards (Exhibit 2); and
- CEDARS Filing Links and Receipts (Exhibit 3).

VII. CONCLUSION

For the reasons described in this Application, and in MCE's testimony in support of this

⁸⁴ Marin Energy Authority Joint Powers Agreement, effective December 19, 2008, as further amended by Amendment No. 17 (Apr. 17, 2025), available at: https://mcecleanenergy.org/wp-content/uploads/2025/10/MCE_JPA-Agreement_38_Communities-Updated_4.17.25.pdf.

Application, MCE respectfully requests that the Commission expeditiously approve this Application and grant the following relief:

- Approve MCE’s 2028-2031 EE Portfolio Plan described in Exhibit 1 of MCE’s testimony, and associated annual budgets described in **Exhibit 1, Chapter 2** of MCE’s testimony;
- Approve MCE’s 2032-2035 EE Business Plan described in Exhibit 1 of MCE's testimony, and associated budget cap described in **Exhibit 1, Chapter 2** of MCE’s testimony;
- Exclude participant costs from the cost-effectiveness tests;
- Permit CCA PAs to adjust Equity segment budget caps to better reflect the Equity population of their service area;
- Clarify its application of the equity segment budget cap;
- Streamline and update definitions of an EE program;
- Reform the EM&V requirements to strengthen transparency, clarity, and administrative efficiencies;
- Better include NEBs in portfolios as more metrics become available; and
- Continue to encourage the inclusion of IDSM programs in EE portfolios.

Respectfully submitted,

By: /s/ Jennifer Green
Jennifer Green

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DATED: March 16, 2026

VERIFICATION

I, the undersigned, say:

I am an officer of Marin Clean Energy, a Community Choice Aggregator, and am authorized to make this verification on its behalf. The statements in the foregoing APPLICATION OF MARIN CLEAN ENERGY FOR APPROVAL OF 2028-2031 ENERGY EFFICIENCY PORTFOLIO PLAN AND 2032-2035 ENERGY EFFICIENCY BUSINESS PLAN are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters, I believe them to be true.

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

Executed on March 16, 2026, at Concord, California.

/s/ Dawn Weisz
Dawn Weisz
Chief Executive Officer

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

Application of Marin Clean Energy for
Approval of 2028-2031 Energy Efficiency
Portfolio Plan and 2032-2035 Energy
Efficiency Business Plan.

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

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

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March 16, 2026

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

Application of Marin Clean Energy for
Approval of 2028-2031 Energy Efficiency
Portfolio Plan and 2032-2035 Energy
Efficiency Business Plan.

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

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

Pursuant to Rule 1.9 of the Commission’s Rules of Practice and Procedure, Marin Clean Energy (MCE) hereby submits this Notice of Availability of the exhibits and supporting documents to the March 16, 2026, *Application of Marin Clean Energy for Approval of 2028-2031 Energy Efficiency Portfolio Plan and 2032-2035 Energy Efficiency Business Plan* (Application).

The supporting material includes:

- | | |
|------------------|--|
| Exhibit MCE – 01 | Testimony of Marin Clean Energy Regarding its 2028-2031 Energy Efficiency (“EE”) Portfolio Plan and 2032-2035 EE Business Plan |
| Exhibit MCE – 02 | EE Program Cards |
| Exhibit MCE – 03 | California Energy Data and Reporting System (“CEDARS”) Filing Links and Receipts |

This Notice of Availability is being served on all parties listed on the official service lists for Rulemaking (R.) 13-11-005, R.25-04-010 and A.22-02-005, *et al.*

As of March 16, 2026, the Application, along with the supporting materials, is available at the following links:

- Application: <https://mcecleanenergy.org/wp-content/uploads/2026/03/MCE-2028-2035-Energy-Efficiency-Application.pdf>

- Exhibit MCE-01: <https://mcecleanenergy.org/wp-content/uploads/2026/03/MCE-2028-2035-Energy-Efficiency-Application-Exhibit1.pdf>
- Exhibit MCE-02: <https://mcecleanenergy.org/wp-content/uploads/2026/03/MCE-2028-2035-Energy-Efficiency-Application-Exhibit2.pdf>
- Exhibit MCE-03: <https://mcecleanenergy.org/wp-content/uploads/2026/03/MCE-2028-2035-Energy-Efficiency-Application-Exhibit3.pdf>
- Certificate of Service: <https://mcecleanenergy.org/wp-content/uploads/2026/03/MCE-2028-2035-Energy-Efficiency-Application-COS.pdf>
- Notice of Availability: <https://mcecleanenergy.org/wp-content/uploads/2026/03/MCE-2028-2035-Energy-Efficiency-Application-NOA.pdf>

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

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Respectfully submitted,

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March 16, 2026

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

Order Instituting Rulemaking Regarding
Policies, Procedures and Rules for the Self-
Generation Incentive Program and Related
Issues.

Rulemaking 20-05-012

**JOINT COMMENTS OF CLEAN ENERGY ALLIANCE, MARIN CLEAN ENERGY,
PENINSULA CLEAN ENERGY AUTHORITY, SAN DIEGO COMMUNITY POWER
AND THE CITY OF SAN JOSÉ ON
ASSIGNED COMMISSIONER RULING ON ENHANCING VERIFICATION OF SELF-
GENERATION INCENTIVE PROGRAM TOTAL ELIGIBLE PROJECT COST
BEFORE DISTRIBUTING INCENTIVE PAYMENTS**

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March 18, 2026

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

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the Self-Generation Incentive Program and Related Issues.

Rulemaking 20-05-012

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BEFORE DISTRIBUTING INCENTIVE PAYMENTS**

Clean Energy Alliance (CEA), Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), San Diego Community Power (SDCP) and the City of San José, administrator of San José Clean Energy (SJCE) (collectively, Joint CCAs) jointly¹ submit these comments to address the questions posed by the *Assigned Commissioner’s Ruling on Enhancing Verification of Self-Generation Incentive Program Total Eligible Project Cost Before Distributing Incentive Payments (TEPC ACR)*, issued on February 20, 2026.² Through these comments, the Joint CCAs also address the *Assigned Commissioner’s Ruling on Verification of Self-Generation Incentive Program High Total Eligible Project Cost Before Distributing Incentive Payments (Verification ACR)*, issued March 13, 2026.³

¹ Pursuant to Rule 1.8(d), each of the Joint CCAs joining these comments have authorized the undersigned to sign and submit these comments on its behalf.

² Rulemaking (R.) 20-05-012, Assigned Commissioner’s Ruling on Enhancing Verification of Self-Generation Incentive Program Total Eligible Project Cost Before Distributing Incentive Payments (Feb. 20, 2026).

³ R.20-05-012, Assigned Commissioner’s Ruling on Verification of Self-Generation Incentive Program High Total Eligible Project Cost Before Distributing Incentive Payments (Mar. 13, 2026). Ordering Paragraph 5 in the Verification ACR states parties may include comments on the process implemented in that ACR as part of their March 18, 2026 comments on the TEPC ACR.

The Joint CCAs appreciate and support the Commission’s efforts to ensure low-income customers can maximally access and benefit from SGIP Residential Solar and Storage Equity (RSSE) funds. The Commission’s concerns regarding Total Eligible Project Cost (TEPC) and the potential for customer out-of-pocket costs are reasonable; however, as the Joint CCAs explain below in response to TEPC ACR Question 7b, high TEPC values do not typically translate to installation costs for participating customers.

The hold on SGIP incentive payments instituted by the TEPC ACR put a tremendous strain on vendors and left low-income customers exposed to delayed or canceled projects. With that said, the Joint CCAs appreciate the clarity and nuance the March 13 Verification ACR introduces, as well as the expeditious action it directs, which will help streamline TEPC verification. However, as the Joint CCAs explain below in response to TEPC ACR Question 7c, without additional improvements, the verification process the Commission envisions is likely to create challenges for vendors who, again, are typically not passing installation costs on to participating customers despite having TEPC above the SGIP incentive level. Specifically, the Joint CCAs recommend the Commission exempt all projects in Group A (i.e., projects falling under Ordering Paragraph 3a of the Verification ACR⁴) and Group B (i.e., projects falling under Ordering Paragraph 3b of the Verification ACR⁵) from additional audit or review provided those projects do not result in any out-of-pocket costs to customers. This modest change will help maintain program integrity while ensuring low-income customers can access and benefit from RSSE funds.

⁴ Group A projects are: “Projects with a TEPC less than 100 percent of the maximum allowed SGIP incentive for that size of project and projects with a TEPC above 100 percent of the maximum SGIP incentive that applied for interconnection before February 20, 2026.” Verification ACR, Ordering Paragraph 3a.

⁵ Group B projects are “Projects with a TEPC above 100 percent of the maximum allowed SGIP incentive for that size of project that have customer out-of-pocket costs less than \$3,000 or are multifamily projects not in Group A.” Verification ACR, Ordering Paragraph 3b.

I. Higher TEPC Values Do Not Typically Translate to Costs for Participating Customers (Response to TEPC ACR Question 7b).

In light of the delta between TEPC and the SGIP incentive and federal investment tax credit (ITC), the TEPC ACR raises the legitimate concern that TEPC levels above the maximum SGIP incentive could lead to customers paying thousands of dollars of costs out-of-pocket, contrary to the goals of the RSSE budget. It states: “the high TEPC means that low-income customers are expected to pay \$2,000-\$11,000 out of pocket for [RSSE projects]”.⁶

This conclusion, however, is incorrect and does not comport with reality. Several CCAs are partnering with Haven Energy on solar + battery programs to support their low-income customers with streamlined installations and access to SGIP incentives. Across the State, Haven Energy has more than 1,500 RSSE projects with confirmed reservations in the SGIP queue. While TEPC for the majority of these projects exceed the maximum incentive amount, it is important to highlight that participating low-income customers do not incur any costs (neither out-of-pocket nor financing costs) under these programs. That means from the customer’s perspective, TEPC are covered by a combination of SGIP incentives and ITC; any costs exceeding SGIP incentives and ITC are assumed by Haven Energy and not charged to customers. This is reflected in the contract that Haven Energy signs with customers, which is submitted to SGIP PAs at the RRF stage.

II. The Commission Should Adopt the Verification Process in the Verification ACR With a Minor Modification (Response to TEPC ACR Question 7c)

While TEPC verification may improve program integrity, the reality is that the current halt on ICF payments has already negatively impacted both customers and the industry. Haven Energy, for example, had to halt all new installs for customers with approved Reservation Requests due to uncertainty over SGIP funding. Haven Energy cannot indefinitely front money for projects and

⁶ TEPC ACR at 5customers.

therefore faces severe business decisions (including bankruptcy) if SGIP ICF funds are not released within the next few months.

The review process proposed in the Verification ACR is a step in the right direction as it prioritizes projects submitted prior to February 20, 2026 and eases requirements for projects with low-to-no out-of-pocket costs. However, the process prescribed by the Verification ACR will not ameliorate vendors’ financing challenges, because it does not prescribe any timeline for PA review of developers’ TEPC documentation. To avoid needless delays or withdrawals of RSSE projects while maintaining program integrity, the Joint CCAs therefore recommend the Commission make the following minor modification to the TEPC verification process proposed in the Verification ACR: For both “Group A” (see Ordering Paragraph 3a in the Verification ACR)), and “Group B” (see Ordering Paragraph 3b in the Verification ACR) projects, developers that do not charge customers any costs (upfront or financing) should be exempt from any additional audit or review requirements and should instead be immediately approved after the PA’s review of the TEPC verification form proposed in the Verification ACR. This modification would ensure that PAs review TEPC verification documents for all developers, while expediting the review process for projects that pose no risk to participating customers—i.e., projects where developers demonstrate that customers do not face any program costs.

III. Conclusion

The Joint CCAs appreciate the Commission’s consideration of these comments and urge the Commission to adopt the recommendations herein.

Respectfully submitted,

A handwritten signature in black ink, appearing to read 'N. Vijaykar', with a stylized flourish at the end.

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Dated: March 18, 2026

Docket No. R.25-02-005

Exhibit No. _____

Date March 23, 2026

Witness Brian Dickman

**TRACK 2 REBUTTAL TESTIMONY OF BRIAN DICKMAN
ON BEHALF OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

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

PUBLIC VERSION

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ATTACHMENTS

Attachment A: Select Discovery Responses

Attachment B: PG&E Response to CalCCA Data Request 4.01, Confidential Attachment 1

1 **I. INTRODUCTION AND SUMMARY**

2 The California Community Choice Association (**CalCCA**)¹ presents this Track 2
3 Rebuttal Testimony in the ! "#\$%&()*+), % + \$/ 01*, %23 4#0)\$%0' #%%\$2"/ %6' \$", 7%
4 - \$(2+"8\$% \$829\$7% 882+')%0' #%% 2<\$"%>0", \$%&#*5\$"\$' 8\$% #?+(/ \$')% 2. *\$\$(%0' #%%
5 ; "28\$(\$(%**OIR**). This Rebuttal Testimony was prepared on behalf of CalCCA by Brian
6 Dickman, Partner, NewGen Strategies and Solutions, LLC. Mr. Dickman’s qualifications
7 are set forth in Attachment B of his Track 2 Direct Testimony.²

8 In their Opening Testimony, Pacific Gas and Electric Company (**PG&E**), Southern
9 California Edison Company (**SCE**), and San Diego Gas & Electric Company (**SDG&E**)³
10 (collectively, **the Joint IOUs**) argue against providing Later Departing Customers⁴
11 compensation for the Pre-2019 Banked Renewable Energy Credits (**RECs**) paid for by
12 those Later Departing Customers when they were bundled customers.

13 My Rebuttal Testimony first offers observations regarding how the Joint IOUs’
14 imprecise use of terminology clouds the issues in this Track 2. First, the IOUs characterize
15 a “collective rights” requirement for receiving value within the Power Charge Indifference
16 Adjustment (**PCIA**) instead of simply referring to the vintage system established by 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 Rulemaking (**R.**) 25-02-005, !"#%&'()*+), % + \$/ 01*, %23 4#0)\$%0' #%%\$2"/ %6' \$", 7% 5#4)l."/)#%5 . - -6/)+0%53.)\$*%7,, .)\$#). / (Mar. 2, 2026) (CalCCA-Dickman Direct Testimony).
³ R.25-02-005, 8.)/+%9 :*/)/ ;% !*, +) - . /0% . 1%<#%)1)\$%=#, %>%?4*\$+)\$%5 . - :#/0%&A.6+3*"/%5#4)l."/)#% ?B), . /%5 . - :#/0%#/B%A#/% (%* ; . %=#, %>%?4*\$+)\$%5 . - :#/0 (Mar. 2, 2026) (Joint IOU Opening Testimony).
⁴ This Rebuttal Testimony uses the terms Previously Departed Customers, Then-Bundled Customers, Later Departing Customers, and Current Bundled Customers as they were defined in the CalCCA-Dickman Direct Testimony. A**%CalCCA-Dickman Direct Testimony at 1, 10-16.

1 PCIA framework. In addition, the Joint IOUs use the terms “value” and “re-value”
2 throughout their Opening Testimony, blurring the lines between the groups of customers
3 paying for and benefitting from the Pre-2019 Banked RECs. To ensure clarity, rather than
4 referring to “value”, my Rebuttal Testimony refers to “payment” or “benefit,” both of
5 which carry a value but have very different implications.

6 My Rebuttal Testimony then responds directly to each of the Joint IOUs’ arguments
7 and demonstrates why their objections to compensating Later Departing Customers for
8 Pre-2019 Banked RECs are unsupported and not consistent with the statutory indifference
9 requirements. More specifically, my Rebuttal Testimony:

- 10 • Clarifies that CalCCA seeks to address a 8+'''\$') cost shift (that may
11 eventually exceed \$1.5 billion), rather than reopen the Pre-2019 PCIA
12 methodology as advanced by the Joint IOUs. The use of Pre-2019 Banked
13 RECs by the IOUs for Current Bundled Customers results in a cost shift
14 today because Later Departing Customers paid for those RECs when they
15 were generated but currently receive no benefit when the RECs are used for
16 Renewables Portfolio Standard (**RPS**) compliance on behalf of Current
17 Bundled Customers.
- 18 • Explains why requiring Current Bundled Customers to pay Later Departing
19 Customers to use the share of Pre-2019 Banked RECs paid for by Later
20 Departing Customers:
 - 21 ○ Does not result in a “re-valuing” of the 2019 Banked RECs because
22 Later Departing Customers have never received their share of any
23 benefits from the Pre-2019 Banked RECs despite their payment for
24 their share of these Pre-2019 Banked RECs when they were Then-
25 Bundled Customers; and
 - 26 ○ Does not result in a cost increase to Current Bundled Customers
27 because those customers never paid for the Later Departing
28 Customer share of the Pre-2019 Banked RECs. If the IOUs are not
29 able to use the Later Departing Customer share for Current Bundled
30 Customer RPS compliance, the IOUs would need to purchase RECs
31 in the market (at a price best approximated by the current market
32 price benchmark (**MPB**)).
- 33 • Observes that the IOUs’ citation to a “collective rights” framework really is
34 just a reference to vintaging, and demonstrates that CalCCA’s proposal is

1 consistent with the PCIA vintaging framework. The proposal provides the
2 benefit of Pre-2019 Banked RECs to existing PCIA vintage groups and does
3 not require individual customer tracking or refunds.

4 • Shows that the Joint IOUs’ argument that Pre-2019 Banked RECs must
5 have a zero-dollar valuation is contradicted by their own Opening
6 Testimony and discovery responses. From an RPS compliance perspective,
7 these RECs function the same as Post-2018 Banked RECs and allow the
8 IOUs to avoid procuring replacement RECs for Current Bundled Customer
9 RPS compliance.

10 • Explains why recognizing value for Pre-2019 Banked RECs does not
11 undermine the Commission’s Voluntary Allocation and Market Offer
12 (VAMO) framework or produce impermissible market impacts. Correcting
13 this cost shift simply ensures that the costs and benefits of renewable
14 procurement are allocated fairly among the customer groups that paid for
15 those resources. Rather than favoring one group of customers over another,
16 CalCCA’s proposal fairly allocates costs based on indifference principles.

17 • Shows that CalCCA’s proposal is readily implementable within the existing
18 PCIA framework despite IOU claims of the proposal being impractical and
19 difficult to implement. The methodology simply relies on vintage-based
20 accounting already used in PCIA ratemaking and has already been applied
21 by PG&E in Energy Resource Recovery Account (ERRA) proceedings.

22 • Demonstrates that the Joint IOUs’ proposal to provide no value for Pre-
23 2019 Banked RECs is inconsistent with the statutory indifference
24 requirement established in Public Utilities Code Section 366.2(g) that the
25 net unavoidable costs paid by departing load customers be reduced by the
26 value of any benefits that remain with bundled service customers, unless
27 those customers receive a fair and equitable allocation of those benefits.

28 **II. CLARIFYING TERMINOLOGY WILL BENEFIT RESOLUTION OF TRACK 2**
29 **ISSUES**

30 The PCIA rests on a complex methodology, and resolution of the questions that
31 arise around the calculation benefit from clarity in the discussion of questions and potential
32 solutions. Before providing the details of my response to the Joint IOUs’ Opening
33 Testimony, my testimony discusses PCIA vintaging versus the Joint IOUs’ terminology of
34 “collective rights” and addresses the concept of “value” in the PCIA.

1 **A. The Joint IOUs’ Discussion of Collective Rights is Simply the Commission’s**
2 **PCIA Vintaging Framework**

3
4 The Joint IOUs refer in their Opening Testimony to “the collective nature of
5 customer entitlements associated with indifference principles,”⁵ implying this is a unique
6 overriding principle that must be observed in this Track. However, their “collective rights”
7 framework is simply the PCIA’s “vintaging” framework. Their Opening Testimony states:

8 [T]he right of bundled service customers under the Pre-2019 methodology
9 to retain REC benefits in a given year, and the right of departing load
10 customers to receive a credit in the indifference calculation for RECs
11 generated in that year, were conferred upon each collective group
12 and not on individual customers.⁶

13 CalCCA’s proposal respects this principle, focusing on vintages and not individual
14 customers.

15 As noted in Opening Testimony, CalCCA’s proposal aims to ensure the
16 indifference of four separate , "2+4(of customers’ vintages: (1) Previously Departed
17 Customers; (2) Then-Bundled Customers; (3) Current Bundled Customers and (4) Later
18 Departing Customers (the latter two resulting from customers departing over time from the
19 category of “Then-Bundled Customers”). As my Rebuttal Testimony explains below,
20 CalCCA’s proposal to credit Later Departing Customers does not blur the lines across these
21 distinct groups of customer vintages nor does it seek to identify individual customers within
22 the groups.

⁵ Joint IOU Opening Testimony at 3; ,**k#4, .&)B0at 26, 27, 46, and 47.

⁶ DB. at 3 (emphasis added). A**k#4, . PG&E response to CalCCA data request 4.15, SCE response to CalCCA data request 4.14, and SDG&E response to CalCCA data request 4.13. All data request responses referenced in this Rebuttal Testimony are attached hereto as Attachment A, with the exception of PG&E response to CalCCA data request 4.01, Confidential Attachment 1, which is attached hereto as Attachment B.

1 **B. The Joint IOUs’ Use of the Term “Value” Clouds the Analysis**

2 The Joint IOUs’ use of the term “value” throughout their Opening Testimony also
3 clouds the analysis of Pre-2019 Banked REC accounting at the heart of Track 2. By using
4 “value” to mean both payments *0’ #* benefits, the Joint IOUs assert that CalCCA’s proposal
5 to provide compensation or allocation to Later Departing Customers for the Pre-2019
6 Banked RECs for which they paid would constitute a “double-valuing” of those RECs.⁷
7 This appears to be in the context of both double-valuing RECs for Previously Departed
8 Customers, and double-valuing RECs that the Then-Bundled Customers had already paid
9 for in the pre-2018 ratemaking methodology; neither assertion of double-valuing is correct.
10 Given the term “value” is being applied in multiple ways by the Joint IOUs, my testimony
11 focuses on the “payment” all customers made for the RECs when they were generated and
12 the allocation of the “benefits” of those RECs to the customers who paid for them.

13 Take, for example, a REC generated and banked in 2015 and used for Current
14 Bundled Customer compliance in 2026. The IOUs are correct that a “value” was assigned
15 to these RECs in 2015; that value, however, represented the payment to Previously
16 Departed Customers through the PCIA because the RECs generated in 2015 would remain
17 with the IOU. While the Then-Bundled Customers paid for all of the RECs generated in
18 2015,⁸ they received no benefit from those RECs at that time because they were banked –

⁷ % A**@k*C;C@kJoint IOU Opening Testimony at 25 (“The Commission’s Pre-2019 PCIA methodology sought to satisfy the requirements of Section 366.2(g) by !"#&' all RECs in the year they were generated and ()*+%,%&'-. , -!"#\$* in the indifference calculation in that same year) (emphasis added); ,**k#4, .k)BCk at 37 (stating that the Pre-2019 Banked RECs were ""#)*"+/- !"#&*+ in bundled customer service rates”) (emphasis added); ,**k#4, .k)BCk at 25 (“CalCCA has proposed applying a new methodology –)C*C@k)*0 !"#& ,%1& of Pre-2019 Banked RECs in the year of compliance use, that did not exist at the time those RECs were previously accounted for in final, settled rates”) (emphasis added).

⁸ “Payment” by bundled customers prior to 2019 had two dimensions. Bundled customers paid the cost of renewable resources for their share of banked RECs; they also paid the RPS MPB – a market price proxy – for the share of the banked RECs that were attributable to Previously Departed Customers.

1 ~~to be~~ placed on the shelf – to be used for the benefit of bundled customers at a later time at
2 the IOUs’ choosing. The benefit to bundled customers arises only when the IOUs use the
3 banked RECs as compliance instruments in 2026 (in this example) for Current Bundled
4 Customers, avoiding the cost of procuring additional RECs to satisfy their compliance
5 obligation at that time.

6 **C. The Joint IOUs Blur the Attribution of Benefits to Departing Customer**
7 **Groups**

8 As noted above, the Joint IOUs claim that Pre-2019 Banked RECs were “already
9 valued” under the Pre-2019 PCIA methodology confuses which customer groups received
10 the benefit of the RECs.⁹ It is critical to understand which of the four separate groups of
11 customers paid for and received the benefits of the RECs during two accounting events:
12 (1) REC banking; and (2) withdrawal from the bank. The Joint IOU Testimony blurs this
13 analysis.

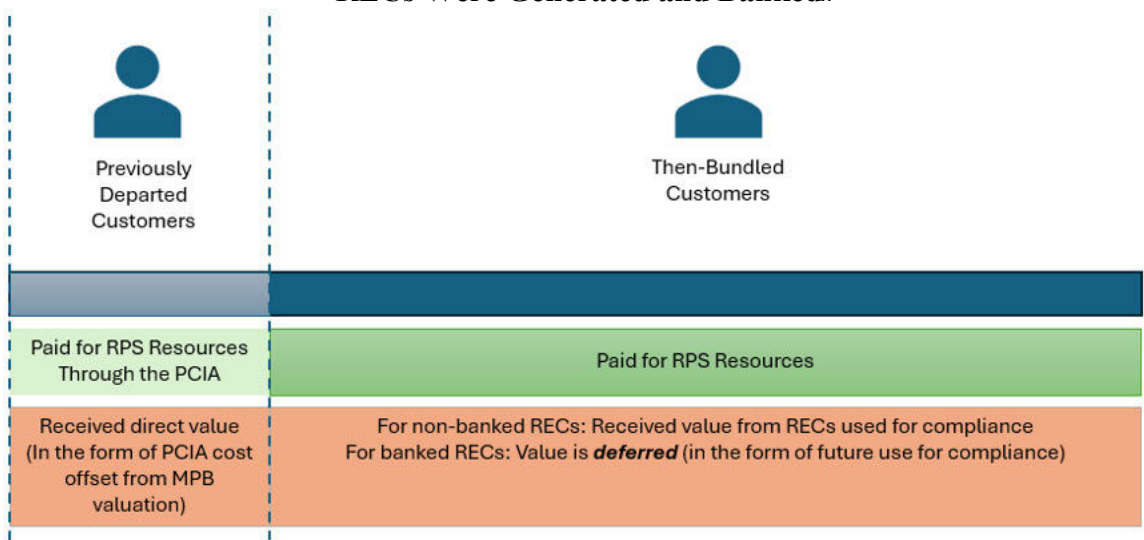
14 As I explain below in Section IV, all customer groups at the time RECs were
15 generated and banked (~~to be~~ Previously Departed Customers and Then-Bundled Customers)
16 paid for their share of the renewable resources that generated the RECs that were banked.
17 Each of the groups must receive a share of the RECs’ benefit, whether through direct use
18 or accounting credit. Previously Departed Customers received their benefit in the form of
19 a credit through the PCIA, but the Then-Bundled Customers received no benefit for RECs
20 that were banked. Because Then-Bundled Customers split into two groups before the
21 banked RECs were used, now that they are being used only one of the groups (~~to be~~ Current
22 Bundled Customers) get any benefit. Under the Joint IOUs’ proposal, the other group that
23 split off, Later Departing Customers, receive no benefits. Providing an accounting credit

⁹ A**@k*C;000Joint IOU Opening Testimony at 31, 37.

1 for Later Departing Customers corrects that inequitable benefit attribution equation.

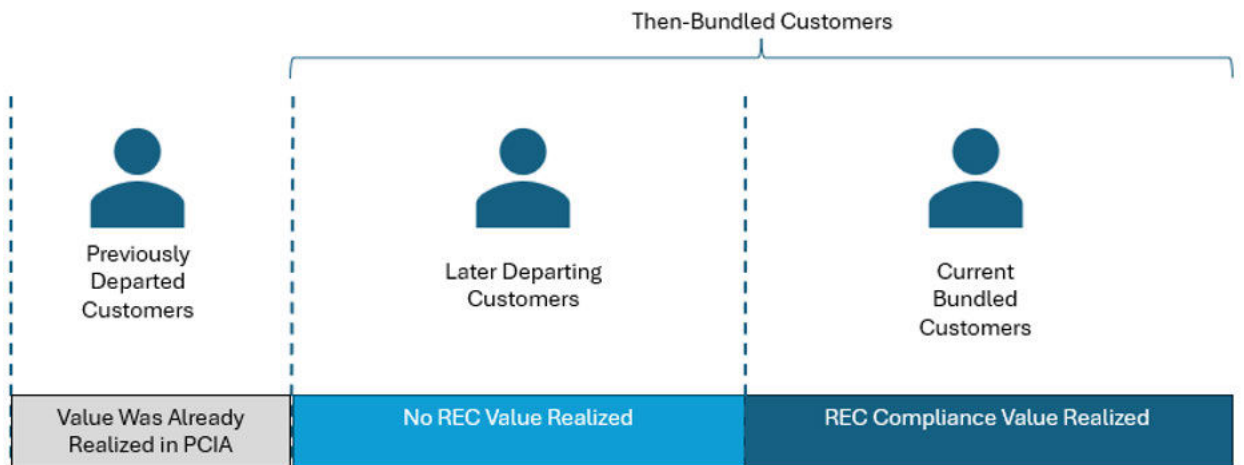
2 Figures 1 and 2, reproduced from my Direct Testimony, show these payments and
3 benefits. Figure 1 demonstrates that when the RECs were generated and banked, only
4 Previously Departed Customer received a benefit. Figure 2 shows that when the Pre-2019
5 Banked RECs are used for Current Bundled Customer RPS compliance, Later Departing
6 Customers do not receive a benefit for their share of the Pre-2019 Banked RECs for which
7 they paid when they were Then-Bundled Customers.

8 **Figure 1: Pre-2019 – Only Previously Departed Customers Received a Benefit When**
9 **RECs Were Generated and Banked#**



10

11 **Figure 2: Current – Only Current Bundled Customers Receive a Benefit When Pre-**
12 **2019 Banked RECs are Used for RPS Compliance**



13

1 **III. CALCCA PROPOSES TO ADDRESS A CURRENT COST SHIFT AND DOES NOT**
2 **SEEK TO OPEN UP PRE-2019 PCIA ACCOUNTING TO ADDRESS PAST COST**
3 **SHIFTS**

4 The Joint IOUs allege that CalCCA’s proposal requires revisiting the pre-2019
5 PCIA methodology and that if the Commission were to address the cost shift associated
6 with Pre-2019 Banked RECs it would necessarily need to revisit and rectify all pre-2019
7 cost shifts that occurred through the PCIA.¹⁰ The Joint IOUs’ argument fundamentally
8 mischaracterizes the nature of the cost shift associated with Pre-2019 Banked RECs.
9 CalCCA’s proposal does not undo or true up a cost shift that occurred in the past. Rather,
10 CalCCA’s proposal addresses a cost shift that recently started occurring since the IOUs
11 began to use Pre-2019 Banked RECs for RPS compliance, and will continue to occur in
12 the future each time Current Bundled Customers benefit through the Joint IOUs’ use of
13 Pre-2019 Banked RECs for RPS Compliance on their behalf (at the expense of the Later
14 Departing Customer group).

15 In fact, CalCCA agrees that pre-2019 PCIA ratemaking should not be reopened and
16 any potential past cost shifts need not be addressed here. It is also clear that CalCCA and
17 the Joint IOUs agree that Then-Bundled Customers paid for the Pre-2019 Banked RECs
18 when they were generated prior to 2019.¹¹ That is precisely what creates the current cost
19 shift associated with the benefit to Current Bundled Customers through the use of Pre-2019
20 Banked RECs – many of the Then-Bundled Customers that paid for those RECs when they
21 were generated have since departed bundled service and become Later Departing
22 Customers. These Later Departing Customers paid for a share of the Pre-2019 Banked

¹⁰ A**()B. at 3.

¹¹ A**()B. at 14-16.

1 RECs but receive no benefit when the RECs are used for Current Bundled Customer RPS
2 compliance today and into the future.

3 **A. The Premise of the Joint IOUs' Argument is Erroneous Because CalCCA is**
4 **Not Seeking to Address a Past Cost Shift**

5 The Joint IOUs argue that “[f]ixing one component of a historical rate while
6 ignoring other known flaws in the former PCIA methodology is ‘cherry picking’ and is
7 inappropriate and unfair.”¹² This argument, however, is based on a flawed assertion that
8 CalCCA proposes to revise the PCIA methodology in place prior to 2019. CalCCA is
9 proposing no such thing; rather, its proposal is to fix a $\delta + \epsilon$ cost shift. The Joint IOU
10 Opening Testimony appears to misunderstand the cost shift stemming from the benefit of
11 using Pre-2019 Banked RECs. The Joint IOUs explain the following regarding the pre-
12 2019 PCIA framework:

13 The [pre-2019] PCIA rates were calculated on a forecast basis with no true-
14 up; however, bundled service customers’ generation rates $< \delta + \epsilon$ trued-up.
15 Therefore, bundled service customers assumed the entirety of the risk that
16 the forecast market value of the vintaged portfolio was overstated and/or
17 that the IOU would be unable to sell excess resources in the market to
18 realize that assumed market value. When those risks materialized, departing
19 load customers paid too little in above-market costs (with no true-up) and,
20 as a consequence, bundled service customers incurred cost increases as a
21 result of departing load ($\delta + \epsilon$ costs were shifted to bundled service
22 customers, with no true-up).¹³

23 As described by the Joint IOUs, in prior years, Then-Bundled Customers were
24 required to pay Previously Departed Customers for the Previously Departed Customers’
25 share of RECs generated that would remain with the IOUs. Prior to 2019, that value ($\delta + \epsilon$
26 the credit for Previously Departed Customers) was determined on a forecast basis and was

¹² DB. at 20.

¹³ DB. at 9-10 (emphasis in original).

1 only true up for Then-Bundled Customers, not Previously Departed Customers.¹⁴ This
2 was one of many factors that led to the Commission initiating Rulemaking 17-06-026 to
3 review the PCIA methodology.

4 The Joint IOU Opening Testimony in this regard highlights two critical points
5 relevant in the current proceeding. First, under the pre-2019 PCIA methodology,
6 Previously Departed Customers received a payment (in the form of a PCIA credit) for their
7 share of the RECs forecasted to be retained by the IOU. Second, Then-Bundled Customers
8 were required to fully pay for all RECs when they were generated, either by paying for
9 their share of the renewable resources or by paying Previously Departed Customers to keep
10 their share of the RECs.

11 The pre-2019 PCIA framework was intended to achieve indifference between
12 Previously Departed Customers and Then-Bundled Customers. Figure 1, above,
13 demonstrates the payments, benefits, and accounting that accomplished this indifference
14 between these two groups. In the current case, CalCCA does not challenge the previous
15 approach, does not ask the Commission to revisit the pre-2019 PCIA methodology, and
16 does not attempt to quantify a cost shift between Previously Departed Customers and Then-
17 Bundled Customers. In other words, whether there was a cost shift resulting from the PCIA
18 methodology prior to 2019, and whether that cost shift was from bundled customers to
19 unbundled customers or vice versa,¹⁵ is not an issue CalCCA proposes to re-open. As

¹⁴ DB. at 16.

¹⁵ The Joint IOUs repeatedly describe the prior PCIA methodology's lack of a true-up as if it were a one-way ratchet that only harmed bundled customers. But just as the lack of a true-up could harm bundled customers (if REC prices were lower than predicted), it could also provide a windfall to bundled customers (if REC prices were higher than predicted). The Joint IOU Opening Testimony, Appendix C, for example, assumes that 1.6% of the Brown Power MPB, Resource Adequacy (RA) MPB, Renewable Premium, and RPS MPB actuals were 20 percent lower than forecast. App. C. If, instead,

1 described by the Joint IOUs, it would likely not even be possible at this point to definitively
2 resolve whether there was a previous cost shift due to the fundamentally different PCIA
3 methodologies pre-2019 and post-2018.¹⁶

4 Instead, CalCCA is concerned with the cost shift that is occurring today resulting
5 from the IOUs' use of (and benefit from) Pre-2019 Banked RECs on behalf of Current
6 Bundled Customers. The use of Pre-2019 Banked RECs exclusively for Current Bundled
7 Customer RPS compliance results in a cost shift today because Later Departing Customers
8 paid for a portion of those Pre-2019 Banked RECs when the RECs were generated. Today,
9 as Figure 2 demonstrates, those Later Departing Customers receive no benefit from the use
10 of the RECs because they have left bundled service and the RECs are only being used for
11 the remaining Current Bundled Customers. The IOUs have only very recently begun to use
12 meaningful quantities of Pre-2019 Banked RECs for RPS compliance, and since it is the
13 use of those RECs that results in a cost shift, that cost shift has only begun to occur in the
14 past few years.

15 **B. CalCCA's Track 2 Proposal Does Not Require the Commission to Address**
16 **Any Element of Historic PCIA Ratemaking**

17 The PCIA design is intended to calculate the indifference amount that ensures there
18 is not a cost shift between bundled and departing customers. It does that by calculating the
19 costs and benefits of IOU generation resources and apportioning those costs and benefits
20 to bundled and departed load by load ratio share based on the vintage of departure. Most

these four prices were 20 percent higher than forecast, the departed load would bear the cost shift. That is, the policy bargain the Commission struck before Decision (D.) 18-10-019 created a PCIA true-up process—both the risks of an unknown future accrued to bundled customers when that future arrived. At 9 (“bundled service customers assumed the entirety of the risk that the forecast market value of the vintaged portfolio was overstated . . .”); SDG&E response to CalCCA data request 4.05, SCE response to CalCCA data request 4.05, and PG&E response to CalCCA data request 4.07.

¹⁶ Joint IOU Opening Testimony at 28-29.

1 generation attributes, such as generation output and capacity that can count toward RA
2 requirements, are benefits realized only in the specific year the generation occurs. RECs
3 are unique in that the payment to procure the attribute occurs in the year of generation, but
4 the benefit for the use of that attribute can be stored for use in later years. It is exactly that
5 characteristic that gives rise to the cost shift experienced today – Later Departing
6 Customers receive no benefit for Pre-2019 Banked RECs when those RECs are used for
7 RPS compliance on behalf of Current Bundled Customers.

8 As I described above and in my Direct Testimony, Then-Bundled Customers paid
9 for all of the Pre-2019 Banked RECs when they were generated by paying for their share
10 of the cost of renewable resources and by paying for Previously Departed Customers' share
11 of RECs. Prior to 2019, the Joint IOUs consistently generated more RECs than they needed
12 for RPS compliance each year.¹⁷ RECs that were not needed at that time for bundled
13 customer compliance were banked for later use. Then-Bundled Customers did not receive
14 any benefit from the banked RECs at that time, and there was no credit given to Then-
15 Bundled Customers. Rather, any benefit provided to Then-Bundled Customers for Banked
16 RECs was only the deferred ability to use the RECs at some future point.%

17 In its Track 2 proposal, CalCCA is not asking the Commission to revisit the cost of
18 generating Pre-2019 Banked RECs that Then-Bundled Customers paid when those RECs
19 were procured. It is also not asking the Commission to revisit the payment (in the form of
20 a PCIA credit) provided to Previously Departed Customers in the year of REC
21 procurement. CalCCA is asking that the Commission ensure that when the benefits of the
22 Pre-2019 Banked RECs are realized, those benefits are allocated fairly to the customer

¹⁷ A**\PG&E, SCE, and SDG&E responses to CalCCA data request 3.01.

1 groups that originally paid for the RECs. Because Later Departing Customers were Then-
2 Bundled Customers when the Pre-2019 Banked RECs were generated, they paid for a load-
3 ratio share of the cost of those RECs and should receive the appropriate proportion of the
4 benefit of the RECs when they are used on behalf of Current Bundled Customers. This
5 issue is very much a current-day problem that requires a current-day solution.

6 **IV. REQUIRING CURRENT BUNDLED CUSTOMERS TO PAY TO USE THE**
7 **SHARE OF PRE-2019 BANKED RECS PAID FOR BY LATER DEPARTING**
8 **CUSTOMERS DOES NOT RESULT IN RE-VALUING THE RECS AND DOES**
9 **NOT RESULT IN A COST INCREASE TO CURRENT BUNDLED CUSTOMERS**

10 The Joint IOU Opening Testimony discusses how CalCCA’s proposal will “re-
11 value” or “double-count” the Pre-2019 Banked RECs which were “already valued” when
12 the RECs were generated, resulting in a “cost increase” for Current Bundled Customers.¹⁸

13 As noted in Section II., above, by stating that the “value” was already provided, the IOUs
14 blur the lines between the elements of value – payments and benefits. In fact, clearly
15 delineating these payments and benefits across the customer groups demonstrates why
16 CalCCA’s proposal is the only result that ensures indifference. As set forth below: (1) no
17 re-valuation of the 2019 Banked RECs will occur because Later Departing Customers have
18 never received their share of the benefits despite their payment for their share of the Pre-
19 2019 Banked RECs when they were Then-Bundled Customers; and (2) no cost increase to
20 Current Bundled Customers will occur because those customers never paid for the Later
21 Departing Customer share of the Pre-2019 Banked RECs and would need to pay for other
22 RPS attributes if they weren’t able to use the Later Departing Customer share.

¹⁸ A**@k *C;C@k Joint IOU Opening Testimony at 2 (“CalCCA asks the Commission to . . . direct #BB+). /#4kF#46* for the Pre-2019 Banked RECs”) (emphasis added), and 4, 19, 28, 29, 30, 34-36, 38, 39, 49-50, 59 (describing CalCCA’s proposal as a “re-valuation” and “requiring valuation of Pre-2019 Banked RECs a second time. . .”).

1 **A. Claiming that CalCCA’s Proposal Will Re-Value the Pre-2019 Banked RECs**
2 **Fails to Acknowledge Later Departed Customers Never Received Any Benefit**

3 As described earlier in my Testimony, prior to 2019, Then-Bundled Customers
4 were required to fully pay for all RECs either by paying for their share of the renewable
5 resources or by paying Previously Departed Customers to keep their share of the RECs in
6 the year the RECs were generated. Figure 1 shows how customers who had departed
7 bundled service at the time the RECs were generated — Previously Departed
8 Customers — did receive a credit at the time of generation, and CalCCA does not seek to
9 change, or true up, the compensation that group of customers received before 2019. The
10 customers at issue here — Later Departing Customers — were still receiving bundled
11 service when the RECs were generated. These customers paid for the RECs to be
12 generated, but they received no credit through the PCIA (because they had not
13 yet departed when the RECs were generated. Therefore, the Joint IOUs’ argument that the
14 RECs were already valued simply does not apply to Later Departing Customers.

15 The Joint IOUs also claim CalCCA’s proposal would “compensate a sub-set of
16 departing load customers that have already reaped the benefits (through a prior valuation
17 of the RECs).”¹⁹ Contrary to that assertion, I demonstrated in my Direct Testimony that
18 conveying the benefit of Pre-2019 Banked RECs through a vintage-specific credit to the
19 PCIA ensures only Later Departing Customers (and not Previously Departed Customers)
20 receive the benefit of their share of the RECs used by the IOU. Later Departing Customers
21 will therefore finally receive a benefit from the RECs for the first time, and Previously
22 Departed Customers receive no additional benefit.

¹⁹ DB. at 48.

1 The Joint IOUs further argue that the Commission’s Pre-2019 PCIA methodology
2 had no mechanism for Later Departing Customers to receive a credit after the fact for RECs
3 generated during the years prior to their departure.²⁰ For example, the Joint IOUs note that
4 if a REC was generated in 2011 and was not used for compliance in 2011 but was then
5 used for compliance in 2012, the 2012 PCIA calculation did not re-value that 2011 REC.
6 However, the Joint IOUs’ argument that the pre-2019 PCIA methodology did not have a
7 mechanism to address this issue means that the Commission should not address it now is a
8 red herring as this hypothetical was simply not a material issue at that time. With only one
9 exception, the Joint IOUs were not using Banked RECs to meet their RPS compliance
10 obligations before 2019.²¹

11 Given these circumstances, it was not necessary to address this issue historically as
12 there was no need to value Pre-2019 Banked RECs when they were not being used for
13 compliance. This issue is significant now given the IOUs’ recent use of Pre-2019 Banked
14 RECs for Current Bundled Customer RPS compliance. The magnitude of the accumulated
15 Pre-2019 Banked RECs and potential cost shift exceeding \$1.5 billion resulting from the
16 Joint IOUs’ use of those RECs should compel the Commission to set the correct policy
17 now.

²⁰ *Id.* at 25-26.

²¹ *See* PG&E, SCE, and SDG&E responses to CalCCA data request 3.01. The IOUs generally had large amounts of excess RECs each year and were not drawing on the bank for RPS compliance prior to 2019. In response to discovery, the Joint IOUs disclosed that between 2011 and 2018 they generated millions of excess RECs each year. Specifically, by the end of 2018, PG&E, SCE, and SDG&E had generated 24.2 million MWh, ██████████ MWh, and 12.0 million MWh of excess RECs, respectively, that were Banked for later use. During that period, neither PG&E nor SDG&E report using any of the excess RECs generated in one year to meet RPS compliance needs in a later year. SCE reports that ██████████

1 **B. Requiring Current Bundled Customers to Pay Later Departing Customers for**
2 **the Pre-2019 Banked RECs for Which Those Later Departing Customers Paid**
3 **Does Not Result in a Cost Increase to Bundled Customers**

4 The Joint IOUs also claim that CalCCA’s proposal requiring Current Bundled
5 Customers to pay Later Departing Customers the current market price for Pre-2019 Banked
6 RECs will result in a cost increase²² and cost shift to bundled customers.²³ They reach this
7 conclusion because Current Bundled Customers would incur a charge equal to the MPB
8 for the RECs through the ERRRA (recovered from bundled customers in generation rates).

9 The observation that a non-zero valuation would increase rates for bundled
10 customers compared to the ()+(~~B~~+2 misses the point: Current Bundled Customers would
11 only be “buying” the share of RECs paid for by Later Departing Customers – Current
12 Bundled Customers only ever paid for their proportional share, not the share paid for by
13 Later Departing Customers when both were Then-Bundled Customers. In addition, Current
14 Bundled Customers would be purchasing RECs for RPS compliance at the Commission’s
15 best estimate of what the market would require if they instead purchased RECs in the
16 market. In this sense, Current Bundled Customers are indifferent to whether they pay the
17 current market price for the Later Departing Customers’ share or go to the market for the
18 same quantity. This payment by Current Bundled Customers is not a cost increase as a
19 result of departing load, but is a cost resulting from the need to procure the minimum
20 required compliance instruments. Thus allocating what are essentially purchase payments
21 to Later Departing Customers for their share of Pre-2019 Banked RECs is simply
22 compensating them for the RECs they originally paid for but that Current Bundled

²² Joint IOU Opening Testimony at 31.

²³ DB. at 40 and 43.

1 Customers are using.

2 **V. CALCCA’S PROPOSAL IS CONSISTENT WITH THE PCIA’S COMPENSATION**
3 **THROUGH VINTAGED GROUPS**

4 The Joint IOUs posit that providing the value of Pre-2019 Banked RECs to Later
5 Departing Customers requires accounting for RECs at the individual customer level²⁴
6 which would run counter to the framework underpinning the PCIA methodology that
7 compensation is conferred on a vintaged group basis. The Joint IOUs are correct that an
8 individual customer accounting of Pre-2019 Banked RECs would be administratively
9 difficult if not impossible to implement.²⁵ However, no such accounting is required for Pre-
10 2019 Banked RECs. CalCCA’s proposal addresses the cost and benefits of Pre-2019
11 Banked RECs by customer groups at the vintage level and therefore is consistent with the
12 PCIA framework.

13 Every year, the PCIA allocates the costs and benefits of IOU procured generation
14 to yearly customer vintages, and as such, departed load customers as a group remain
15 obligated to pay ongoing above-market costs for the IOUs’ PCIA-eligible resources.²⁶ A
16 departing load customer is charged the PCIA based on their vintage group, or year of
17 departure.²⁷ This framework ensures all customers within the same vintage receive the
18 same costs and benefits. The share of Pre-2019 Banked RECs originally paid for by Later
19 Departing Customers can be determined based on total departed load by vintage. CalCCA’s
20 proposal is to credit the benefits of Pre-2019 Banked RECs used for compliance to a

²⁴ A**B. at 26-27.

²⁵ A**B. at 29.

²⁶ A**SDG&E response to CalCCA data request 4.04, SCE response to CalCCA data request 4.04, and PG&E response to CalCCA data request 4.06.

²⁷ A**SDG&E response to CalCCA data request 4.13, SCE response to CalCCA data request 4.14, and PG&E response to CalCCA data request 4.15.

1 specific PCIA vintage, based on the year the RECs were generated, thereby spreading the
2 credit to all customers in the impacted vintages. The mechanics of this proposal are
3 supported by the PCIA framework, rather than running counter to that framework. CalCCA
4 does not seek customer-specific accounting or individual customer refunds.

5 The Joint IOUs point to D.06-07-030 as precedent for not giving Later Departing
6 Customers value for the Pre-2019 Banked RECs they paid for, arguing that the
7 Commission determined that individual customers departing bundled service are not
8 entitled to receive bill credits for a share of a refund amount owed to bundled customers
9 on a group basis.²⁸ The Joint IOUs describe that bundled customers were entitled to a
10 refund, or repayment, of a “CRS under-collection loan” to direct access customers. The
11 IOU parties had opposed a proposal to provide individual bill credits for a share of the
12 refund to customers departing bundled service because it would be too complex to
13 implement and the departing load was not subject to other balancing accounts that may be
14 under-collected at the time the customers depart.

15 The circumstances surrounding CalCCA’s proposal to provide the benefits for Pre-
16 2019 Banked RECs when they are used for RPS compliance are notably different than the
17 issues addressed in D.06-07-030. First, CalCCA does not propose to track individual
18 customers or provide individual bill credits. Instead, CalCCA’s proposal to convey the
19 value of Pre-2019 Banked RECs to Later Departing Customers is based on the same
20 vintage framework as other PCIA costs and benefits. The share of Pre-2019 Banked RECs
21 attributed to Later Departing Customers would be determined based on vintage load, and
22 the value would be credited to a PCIA vintage.

²⁸ A**\Joint IOU Opening Testimony at 46.

1 Second, Public Utilities Code Section 366.2(g) was added in 2011 to clarify that
2 IOU generation procurement costs paid by the customers of a CCA shall be reduced by the
3 value of any benefits that remain with bundled service customers. Therefore, CalCCA’s
4 proposal is consistent with the current statutory indifference framework.²⁹

5 The PCIA functions by assigning departing load customers to vintage groups and
6 then assigning those vintage groups the costs and benefits collectively. As described in
7 detail in my Direct Testimony, CalCCA’s proposal to convey the benefits of Pre-2019
8 Banked RECs to Later Departing Customers is based on the same vintage framework as
9 other PCIA costs and benefits.

10 **VI. THE JOINT IOUS’ ARGUMENT THAT THE PRE-2019 BANKED RECS ARE**
11 **CATEGORICALLY DIFFERENT AND MUST HAVE ZERO VALUE IS**
12 **UNDERMINED BY THE IOUS’ OWN TESTIMONY**

13 The Joint IOUs argue that Pre-2019 Banked RECs can only be assigned a value of
14 zero in the PCIA framework.³⁰ However, that conclusion is inconsistent with the IOUs’
15 own discovery responses and Opening Testimony, and with how those RECs are used to
16 satisfy RPS compliance requirements for bundled customers. As the Joint IOUs
17 acknowledge in their Testimony, Pre-2019 Banked RECs can be used by the IOUs to meet
18 their current RPS compliance obligations in the same manner as RECs generated after

²⁹ One aspect of the IOU parties’ opposition leading to D.06-07-030 was an argument that departing load was not subject to other balancing accounts that may be under-collected at the time the customers depart. While CalCCA’s Pre-2019 Banked REC proposal is not a retroactive true-up, it is noteworthy that the Commission does now require departing load customers to be responsible for under- or over-collections recorded in balancing accounts at the time the customer departs. For example, departing load became subject to the Portfolio Allocation Balancing Account (**PABA**) to true up PCIA costs and benefits beginning in 2019. In addition, in D.22-01-023, the Commission adopted a Joint IOU proposal that the year-end ERRA balancing account, which trues up bundled customer generation costs, should be transferred to the most recent PABA vintage subaccount so that customers who depart bundled service after the true up is recorded remain responsible for their share of the balance. A** D.22-01-023 at 13-14 and Ordering Paragraph 4.

³⁰ A** Joint IOU Opening Testimony at 59.

1 2019.³¹ From the perspective of RPS compliance, a banked REC generated before 2019
2 performs the same fundamental function as a REC generated after 2019. Without access to
3 the Pre-2019 Banked RECs for RPS requirement purposes, the IOUs would have to incur
4 an incremental expense to procure the RECs needed to meet RPS compliance. The Joint
5 IOUs cannot have it both ways – they cannot benefit from the use of Pre-2019 Banked
6 RECs by avoiding an incremental cost but then argue those RECs provide no benefit (0%
7 value).

8 Both SCE and PG&E acknowledged in discovery that there is no difference
9 between a REC banked before and after 2019 for purposes of RPS compliance.³² The Joint
10 IOUs’ Opening Testimony reiterates that point.³³ This fact is important because the value
11 of a REC within the PCIA framework is tied directly to its ability to satisfy RPS compliance
12 obligations when used by the IOU for bundled customers.

13 The Joint IOUs argue that Pre-2019 Banked RECs should be assigned a value of
14 zero because they lack some attributes associated with more recently procured renewable
15 resources. For example, the Joint IOUs note that the RPS MPB is derived from transactions
16 involving PCC-1 renewable products that include bundled energy and renewable attributes,
17 can be transferred between parties, and may be used for additional purposes such as
18 greenhouse gas accounting or power content label disclosures.³⁴ CalCCA does not claim
19 that retired RECs are identical to current period RPS generation in all respects. But that is
20 not the relevant question—Pre-2019 Banked RECs can be used to meet current bundled
21 customer RPS compliance needs for the IOUs just as well as Post-2018 Banked RECs.

³¹ A**\B. at 44.

³² A**\PG&E and SCE responses to CalCCA data request 3.09.

³³ A**\Joint IOU Opening Testimony at 44.

³⁴ A**\B.

1 Under CalCCA’s proposal, the IOUs would retain the Pre-2019 Banked RECs and use
2 them for compliance on behalf of Current Bundled Customers. Accordingly, the relevant
3 attribute of the REC (its benefit) is its ability to satisfy RPS requirements. Furthermore,
4 the Joint IOU Opening Testimony explains that only PCC-0 and PCC-1 RECs can be
5 banked.³⁵ When the IOU keeps these banked RECs they “effectively live on beyond their
6 retirement”³⁶ and can be counted toward RPS compliance requirements in the future,
7 offsetting the need for procurement of similar products later.

8 The Joint IOUs also highlight the Pre-2019 Banked RECs’ limitation that they
9 cannot be transferred to a third party because they have already been retired in WREGIS.³⁷
10 However, CalCCA’s proposal does not require the RECs to be transferred at all. As
11 described earlier, under the valuation proposal the RECs should continue to be used by the
12 IOUs for RPS compliance.³⁸

13 Furthermore, the non-transferability of banked RECs is not unique to Pre-2019
14 Banked RECs. A REC must be retired in WREGIS for RPS Compliance within three years
15 of its generation.³⁹ Once it is retired in WREGIS it is not available to be sold or transferred,
16 but it is available to meet future RPS requirements. That is the situation for all Pre-2019
17 Banked RECs and is also the situation for Post-2018 Banked RECs generated in 2019,
18 2020, 2021, and 2022. When Post-2018 Banked RECs that have been retired in WREGIS
19 are used for RPS compliance, the value of those RECs is measured by the RPS MPB in the
20 year they are used. The fact that these banked RECs are retired in WREGIS and that many

³⁵ A**\B., Appendix B at B-5.

³⁶ A**\B.

³⁷ A**\B. at 51.

³⁸ Under the alternative, allocation proposal, the allocated RECs would be used to adjust the Net RPS Procurement Need as measured on the Commission’s Renewable Net Short Calculation template.

³⁹ A**\Joint IOU Opening Testimony, Appendix B at B-4.

1 of them cannot now be transferred to a third party does not make them any less able to
2 serve as RPS compliance for an IOU. It also does not mean that these banked RECs are
3 any less able to permit an IOU to avoid the cost of procuring RPS compliance RECs in the
4 market.

5 The distinguishing characteristics the Joint IOUs raised regarding banked RECs are
6 irrelevant to the question at hand, and do not alter the fundamental fact that Pre-2019
7 Banked RECs can be used by the IOUs to satisfy current RPS compliance requirements
8 and that Pre-2019 Banked RECs are no different than Post-2018 Banked RECs when used
9 by the IOU for bundled customer compliance. Providing a zero valuation for the use of
10 Pre-2019 Banked RECs is clearly unreasonable, and arguments to change the RPS MPB
11 are more appropriate for Track 3 of this proceeding. The Pre-2019 Banked RECs should
12 therefore be valued using the RPS MPB when the RECs are used for Current Bundled
13 Customer compliance.

14 **VII. CORRECTING A COST SHIFT TO ENSURE STATUTORY INDIFFERENCE IS**
15 **APPROPRIATE REGARDLESS OF THE IMPACT ON IOU PROCUREMENT**
16 **INCENTIVES**

17 The Joint IOUs devote substantial testimony to arguing that recognizing a non-zero
18 value for Pre-2019 Banked RECs would produce impermissible downstream
19 consequences, including harm to the RPS market and reduced incentives for the IOUs to
20 sell excess renewable resources. The Joint IOUs' argument, however, assumes that
21 correcting a cost shift to ensure statutory indifference is inappropriate if it changes IOU
22 procurement incentives. The Joint IOUs' arguments do not provide a valid basis for
23 maintaining a non-zero valuation of Pre-2019 Banked RECs.

24 Much of the Joint IOUs' argument rests on the premise that the Commission likely
25 adopted the VAMO framework because the IOUs possessed significant excess renewable

1 resources, including banked RECs from prior years. The Joint IOUs suggest that
2 recognizing value for Pre-2019 Banked RECs would undermine the conditions that
3 justified VAMO.⁴⁰ However, the Commission’s decision adopting and implementing
4 VAMO does not support that conclusion.

5 For example, the Joint IOUs point to D.18-10-019 and D.21-05-030 as evidence
6 that the IOUs’ renewable portfolios contained excess resources that could be used to meet
7 compliance requirements in future years.⁴¹ While those decisions acknowledge that the
8 IOUs had renewable resources beyond near-term compliance needs, the Commission did
9 not identify the IOUs’ REC banks as contributing to those excess resources.

10 The Joint IOUs argue the RPS resources allocated under VAMO were only excess
11 because an IOU is able to use its Pre-2019 Banked RECs – without having to procure them
12 again – to meet its compliance requirements.⁴² On the contrary, the fact that the IOUs were
13 accumulating banked RECs is evidence that their annual RPS-eligible generation
14 significantly exceeded bundled customer needs at the time. The Commission decision
15 highlights that CalCCA pointed out then that the annual ERRA forecast proceedings
16 included significant amounts of excess RPS resources that were counted as Unsold RPS
17 under the updated PCIA framework adopted in 2019.⁴³ Decision 21-05-030 defined
18 “excess resources” simply as those not necessary to meet bundled customers’ needs and
19 compliance requirements, and the Commission concluded that voluntary allocation of the

40 A**()B. at 4.

41 A**()B. at 18.

42 A**()B. at 32.

43 D.21-05-030 at 16-17.

1 IOUs’ annual RPS generation could help “reduce excess and/or uneconomic resources in
2 the IOUs’ PCIA portfolios.”⁴⁴

3 Decision 21-05-030 also recognized that the amount of excess RPS resources could
4 decline significantly over time. The Commission stated that excess renewable resources
5 could “decline precipitously within the next few years,” and as a result the Commission
6 limited the frequency of voluntary allocation solicitations.⁴⁵ In other words, the
7 Commission adopted VAMO with the expectation that the IOUs’ excess RPS generation
8 in the current period would decline. The Commission specifically rejected PG&E’s
9 argument that it should not require IOUs to dispose of resources needed for bundled service
10 customer compliance because the IOUs would be required to procure additional resources
11 for compliance on the market.⁴⁶ The Commission acknowledged that replacing resources
12 could increase costs for bundled ratepayers, although market prices at that time were likely
13 to be lower than the cost of legacy RPS contracts.⁴⁷

14 The Joint IOUs further argue that recognizing value for Pre-2019 Banked RECs
15 could reduce the effective availability of those RECs and create market inefficiencies.⁴⁸
16 According to the Joint IOUs, if banked RECs were assigned a value based on the RPS MPB
17 the IOUs might choose not to use those RECs for compliance if alternative procurement
18 options were less expensive.⁴⁹ It should be noted that when making this argument, the Joint

⁴⁴ DB. at 58, Conclusion of Law 2.

⁴⁵ DB. at 33-34.

⁴⁶ A**\B. at 19.

⁴⁷ A**\B.

⁴⁸ A**\Joint IOU Opening Testimony at 34-35.

⁴⁹ A**\B. at 35. The Joint IOUs’ argument that they may forgo utilizing Pre-2019 Banked RECs because procuring additional RECs on the market might be less costly than valuing the Pre-2019 Banked RECs at the RPS MPB is the opposite of the position taken by PG&E when faced with a similar circumstance related to providing substitution RA for the Diablo Canyon Nuclear Power Plant (**DCPP**)

1 IOUs necessarily admit that the Pre-2019 Banked RECs can serve as a substitute to
2 purchasing RECs, including PCC 1 RECs, for RPS compliance.⁵⁰

3 The Joint IOUs already evaluate multiple options when determining how best to
4 meet RPS compliance obligations and they should adopt procurement strategies that
5 balance the IOUs' portfolio while minimizing total costs for all customers, including the
6 use of banked RECs, the procurement of new renewable resources, and participation in
7 REC markets. The Commission should ensure that the Joint IOUs prudently optimize their
8 RPS portfolios to minimize total cost while ensuring Later Departing Customers receive
9 the value of RECs they paid for. Recognizing the value of Pre-2019 Banked RECs simply
10 ensures that the costs and benefits of the IOUs' strategies and decisions are properly
11 assigned to the appropriate customer groups.

12 It is also important to recognize that only a portion of the Pre-2019 Banked RECs
13 would require compensation to Later Departing Customers under CalCCA's proposal.
14 Some of those RECs were paid for by Then-Bundled Customers who remain bundled today

during extended operations. In the 2026 DCPD Forecast proceeding (A.25-03-015), the Alliance for Nuclear Responsibility (A4NR) recommended that PG&E should purchase capacity needed for DCPD substitution capacity from the RA bilateral market because it could be purchased at a lower cost rather than use capacity that already exists in the PCIA-eligible portfolio but which would be valued at the RA MPB (and charged to the DCPD extended operations balancing account) when used for DCPD needs. A.25-03-015, Rebuttal Testimony of PG&E, page 3-1, lines 22-28. PG&E responded to A4NR's proposal arguing, "Consistent with portfolio planning and management practices, PG&E uses capacity from its existing portfolio to meet its RA compliance obligations, including its California Independent System Operation Corporation (CAISO) substitution capacity obligations. In the event that PG&E does not have sufficient capacity from its existing portfolio, PG&E makes attempts to purchase capacity from the RA market to meet the shortfall. Requiring PG&E to effectively disregard capacity from its existing portfolio and solely rely on the RA market for DCPD's substitution capacity is nonsensical and would increase the total cost for customers." A.25-03-015, PG&E response to A4NR's proposal, page 3-6, lines 4-12.

⁵⁰ Joint IOU Opening Testimony at 40; PG&E response to CalCCA data request 4.29.

1 and there is no additional net cost to Current Bundled Customers for these RECs under
2 CalCCA's proposal.⁵¹

3 CalCCA acknowledges that the IOUs may revisit their procurement strategies in
4 response to the Commission's decision in this proceeding. However, utilities frequently
5 adjust procurement strategies and individual procurement decisions in response to changes
6 in regulatory policy and market conditions. Ensuring that the customer indifference
7 principle is applied correctly within the PCIA framework does not create an impermissible
8 market outcome; it ensures that the costs and benefits of procurement decisions are
9 allocated fairly among customers.

10 Finally, if the Commission is concerned that assigning a monetary value to Pre-
11 2019 Banked RECs could affect REC market behavior, the Commission could allocate the
12 RECs themselves among load-serving entities (LSEs). Allocating the RECs among LSEs
13 would ensure that all customers who paid for those resources receive their fair share of the
14 benefits while avoiding any potential concerns regarding market valuation.

15 **VIII. THE JOINT IOUS' ARGUMENT THAT CALCCA'S PROPOSAL CANNOT BE**
16 **IMPLEMENTED IS CONTRADICTED BY THEIR OWN PREVIOUS FILINGS**

17 The Joint IOUs attempt to paint CalCCA's proposal as overly complicated. They
18 state:

19 To provide a simplified and conceptual idea of what would be involved in
20 re-valuing Pre-2019 Banked RECs in a manner that avoids additional cost
21 shift to bundled service customers, and without delving into the complicated
22 ratemaking mechanics that would be involved it would be necessary as a
23 starting point for each IOU to (i) individually identify each and every
24 departing load customer in every year from 2011 to 2018; (ii) individually
25 identify each and every Later Departing Customer and the years in which
26 they were still bundled customers; (iii) develop a ratemaking mechanism

⁵¹ As discussed in my Direct Testimony, Current Bundled Customers are in the IOUs' most recent customer vintage, and CalCCA's proposal will ensure they receive value of the proportion of RECs they already paid for. A***(CalCCA-Dickman Direct Testimony at 7.

1 that requires departing load customers from 2011 to 2018 to credit back the
2 cost shift to current bundled service customers and the specific Later
3 Departing Customers who were bundled service customers in each relevant
4 year the credit they received for Pre-2019 RECs in each year they were
5 generated.⁵²

6 These complications raised by the Joint IOUs misrepresent CalCCA’s proposal.

7 First, as I have demonstrated in my Direct and Rebuttal Testimony, CalCCA’s
8 proposal is not a true up of pre-2019 PCIA accounting, and it is not tied to a requirement
9 to somehow identify and quantify all past cost shifts.

10 Second, and most conspicuous, the Commission has already implemented
11 CalCCA’s proposed vintage-specific PCIA credit methodology for PG&E. In fact,
12 CalCCA’s proposal to credit Pre-2019 Banked RECs at the RPS MPB was originally
13 proposed by PG&E, and PG&E has used this approach to value banked RECs (including
14 RECs generated in 2018) used for bundled customer compliance in its ERRA Forecasts
15 since 2023.⁵³ As I described in my Direct Testimony, PG&E argued in its 2023 ERRA
16 Forecast testimony that all of its banked RECs through that point were paid for by
17 customers who received bundled service in the year the RECs were generated.
18 Accordingly, when PG&E used the banked RECs for compliance, PG&E credited the
19 PCIA vintages corresponding to the years in which the banked RECs were generated by
20 applying the then-current forecast RPS MPB to the quantity of banked RECs utilized.⁵⁴

21 CalCCA’s proposal is discussed in detail in my Direct Testimony, including the
22 mechanics of crediting the Pre-2019 Banked RECs to the PCIA vintage matching the year

⁵² Joint IOU Opening Testimony at 29.

⁵³ A** PG&E response to CalCCA data request 4.01, Confidential Attachment 1, ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_004-Q001Atch01CONF.xlsx (in Tab E) Min Retained RPS 2024) (pages 135-137 of Attachment B); PG&E response to CalCCA data request 4.02.

⁵⁴ A** PG&E response to CalCCA data requests 4.02.

1 the banked RECs were generated. The only information required to calculate the proper
2 credit is the quantity of banked RECs needed for compliance, the year the RECs were
3 generated, and the current RPS MPB. The Joint IOUs describe the infeasibility of an
4 individual remedy (proposed by no party but the Joint IOUs) to attempt to defeat CalCCA's
5 proposed group level remedy.

6 The Joint IOUs also raise the complication of customers that migrate between
7 bundled and unbundled service, including customers that departed bundled service before
8 a REC was banked, returned to bundled service, and then re-departed.⁵⁵ That is a very
9 small subset of an already small group of customers. In fact, when asked in discovery only
10 SDG&E was even able to quantify this group, and it totaled 91 customers.⁵⁶ The majority
11 of departing load customers have remained departing load customers and do not return to
12 bundled service then re-depart. However, it is worthwhile to understand the consequences
13 of valuing Pre-2019 Banked RECs for this set of customers between 2011 and 2018.
14 Through the PCIA framework in place at the time, Previously Departed Customers would
15 have already received compensation for RECs generated while taking unbundled service.
16 They would also have paid the cost of RECs and received no benefit for RECs generated
17 while later taking bundled service. When re-departing, these customers would be assigned
18 to the PCIA vintage of the year of re-departure. Consequently, when Pre-2019 Banked
19 RECs are used for compliance in the future, these customers will receive benefits through
20 the PCIA if the RECs were generated in a year prior to their re-departure. To the extent
21 these customers exist, they will benefit twice from the same REC procurement cost (once

⁵⁵ A** Joint IOU Opening Testimony at 29.

⁵⁶ A** SDG&E response to CalCCA data request 4.12, SCE response to CalCCA data request 4.13, and PG&E response to CalCCA data request 4.14.

1 if they were Previously Departed Customers and credited for the REC in the year of
2 generation, and a second time if they are Later Departing Customers when the REC is used
3 for compliance). Given this is a very small sub-set of customers, this small amount of
4 additional benefit should not stand in the way of rectifying the much larger cost shift that
5 is occurring for millions of customers.⁵⁷

6 **IX. SECTION 366.2(G) REQUIRES THAT NET UNAVOIDABLE COSTS PAID BY**
7 **CCA CUSTOMERS BE REDUCED BY THE VALUE OF ANY BENEFITS THAT**
8 **REMAIN WITH BUNDLED SERVICE CUSTOMERS**

9 The Joint IOUs' proposal to provide no value for Pre-2019 Banked RECs is
10 inconsistent with the statutory requirement established in Public Utilities Code Section
11 366.2(g) that the net unavoidable costs paid by departing load customers be reduced by the
12 value of any benefits that remain with bundled service customers, unless those customers
13 receive a fair and equitable allocation of those benefits. As I explained earlier in my
14 Rebuttal Testimony, Later Departing Customers were Then-Bundled customers when the
15 Pre-2019 Banked RECs were generated and therefore paid their load-ratio share of the
16 costs associated with those renewable resources. As Figure 2 shows, when the IOUs use
17 these RECs for RPS compliance on behalf of Current Bundled Customers, the benefit of
18 those renewable attributes remains entirely with the Current Bundled Customers. In this
19 case, Later Departing Customers (as a collective group) paid for a share of the renewable
20 attributes when the RECs were generated but receive no benefit when those attributes are
21 used exclusively for Current Bundled Customer (as a collective group) compliance.

22 The Joint IOUs point to statutory requirements that bundled customers shall not
23 experience any cost increase as a result of the retail customers electing to receive service

⁵⁷ A**CalCCA-Dickman Direct Testimony at 13-14 (citing SCE response to CalCCA 3.14, PG&E response to CalCCA 3.14, and SDG&E response to CalCCA 3.14).†

1 from other providers⁵⁸ and characterize any provision of the Pre-2019 Banked REC value
2 as a cost increase for bundled customers. As noted above, the Joint IOUs simultaneously
3 plan to rely on a share of Pre-2019 Banked RECs paid for by Later Departing Customers
4 to satisfy RPS compliance obligations while asserting that those Later Departing
5 Customers should receive nothing in return. The Joint IOUs would therefore use the Later
6 Departing Customer share of RECs at no cost, while the Later Departing Customers lose
7 the benefit of what they paid for. Also as recognized in Section IV.B., above, if those RECs
8 were not available, the IOUs would need to procure replacement RECs through the current
9 market to meet their compliance obligations. The avoided procurement cost associated with
10 the use of Banked RECs is an economic benefit associated with the renewable resources
11 originally paid for by the customer groups that funded their procurement (***Then-
12 Bundled Customers who later split into Current Bundled and Later Departing Customer
13 groups).

14 Section 366.2(g) provides two ways to ensure compliance with the statute. The
15 Commission may either credit Later Departing Customers with the value of the benefits
16 retained by Current Bundled Customers, or it may allocate the underlying attributes
17 themselves. CalCCA's proposal to value Pre-2019 Banked RECs based on the RPS MPB
18 when the RECs are used for compliance represents a straightforward application of the first
19 option and recognizes the current benefits being received by Current Bundled Customers.
20 Alternatively, the statute also supports allocating those RECs among LSEs so that all
21 customers who paid for their procurement receive their fair share of the benefits.
22

⁵⁸ A**\Joint IOU Opening Testimony at 23-24.

1 This concludes my Testimony.

ATTACHMENT A

Select Discovery Responses

**PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response**

PG&E Data Request No.:	CalCCA_003-Q001
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_003-Q001CONF
Request Date:	February 2, 2026
Requester DR No.:	003
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	February 17, 2026
PG&E Witness(es):	Christa Hoffman – Energy Policy and Procurement

QUESTION 001

Regarding PG&E’s REC bank, please provide the following:

- a. The quantity of RECs ‘deposited’ and ‘withdrawn’ on an annual basis, summarized by the year the RECs were generated since 2010.
- b. The quantity of RECs remaining in the REC bank as of January 1, 2026, summarized by the year the RECs were generated.

ANSWER 001 –

The confidential material is being provided pursuant to the accompanying confidentiality declaration.

PG&E objects to the use of the terms “deposited” and “withdrawn” and “REC bank” on the basis that such terms are not clearly defined and are vague. Notwithstanding, and subject to the following objection,

- a. Please see the table below for a summary of RECs generated in excess or PG&E’s annually imputed RPS obligation and/or used towards minimum retained RPS requirements as established in PG&E’s ERRA Forecast proceeding.

Generation Year	RECs Generated Above Annual RPS Requirement	RECs Used Towards Minimum Retained RPS Requirement			
		2023	2024	2025	2026
2011	-	-	-	[REDACTED]	
2012	-	-	-		
2013	1,928,480	-	-		
2014	3,980,017	-	-		
2015	4,482,478	-	-		
2016	5,379,425	-	-		
2017	3,704,274	-	-		
2018	4,773,405	-	-2,692,131		
2019	-	-	-		
2020	445,318	-	-		
2021	5,399,732	-3,211,076	-2,188,656	-	-
2022	1,322,452	-786,427	-536,025	-	-
2023	-	-	-	-	-
2024	-	-	-	-	-
2025	-	-	-	-	-
2026	[REDACTED]	-	-	[REDACTED]	
Total	[REDACTED]	-3,997,503	-5,416,812	[REDACTED]	

b. In the table above, adding the totals shown for the first four columns (through 2025) can be done to determine the quantity of RECs remaining as of January 1, 2026, which is [REDACTED]

**PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response**

PG&E Data Request No.:	CalCCA_003-Q009
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_003-Q009
Request Date:	February 2, 2026
Requester DR No.:	003
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	February 17, 2026
PG&E Witness(es):	Christa Hoffman – Energy Policy and Procurement

QUESTION 009

Assume PG&E’s REC bank contains RECs generated and banked from the same RPS-eligible resource prior to 2019 as well as in 2019 or later. For purposes of RPS compliance, is there any difference between the RECs banked prior to 2019 versus the RECs banked in 2019 and later? Please explain.

ANSWER 009

While in RPS compliance there is not a distinction between RECs generated before or after 2019, there is a significant difference between these RECs when valued for ratemaking purposes due to changes in revenue requirements and ratemaking adopted by D.18-10-019 and D.19-10-001.

PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response

PG&E Data Request No.:	CalCCA_004-Q002
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_004-Q002
Request Date:	March 6, 2026
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	March 17, 2026
PG&E Witness(es):	Erica Brown – Energy Policy and Procurement

QUESTION 002

Please refer to Hearing Transcript pp. 111-114 in PG&E’s 2026 ERRA Forecast Case (A.25-05-011). Please confirm the following representations of Ms. Barry:

- a. In PG&E’s 2025 ERRA Forecast Case (A.24-05-009), PG&E initially forecast an RPS shortfall for 2025 and anticipated using RECs generated in 2018 and 2020 towards its forecast shortfall.
- b. In response to discovery request CalCCA 4.02 in PG&E’s 2025 ERRA Forecast Case (A.24- 05-009), PG&E proposed to value the 2018 banked RECs used to meet the 2025 minimum retained RPS at the Forecast RPS Adder.

ANSWER 002

- a. PG&E confirms that in its 2025 ERRA Forecast - Fall Update, a minimum retained RPS shortfall was forecasted for 2025. To satisfy the minimum retained RPS requirements for 2025, PG&E forecasted the use of excess RECs generated in 2018 and 2020 to cover that shortfall. The use of excess RECs generated in 2018 was the result of the Commission’s order to PG&E that RECs banked in or after 2019 begin with RECs that were generated in 2018.¹ To be clear, PG&E’s initial May 2024 Testimony for the 2025 ERRA Forecast did not show a need to use banked RECs to meet minimum retained RPS compliance obligations. PG&E’s Rebuttal Testimony anticipated there would be a need and the Fall Update Testimony confirmed there was a forecast need to use RECs banked in or after 2019 to meet the minimum retained RPS compliance target for 2025.
- b. PG&E would not characterize this response as a PG&E proposal. PG&E was responding to a question - which asked - will PG&E use the Forecast RPS Adder to value the 2018 banked RECs it anticipated would be needed to meet the minimum

¹ See D.23-12-022, p. 17 and Ordering Paragraph 5.

retained RPS compliance targets. PG&E said yes. This was not a PG&E proposal but, rather, it was a response to a question.

PG&E's Opening Testimony in May confirmed its intent to be compliant with the D.23-12-022 directives and PG&E's response to the discovery reflected an intent to be compliant with the Commission's directives in D.23-12-022. See PG&E's May 2024 Opening Testimony for the 2025 ERRA Forecast Proceeding, Chapter 10, p. 10-19, lines 1 – 7 and associated footnotes 34 and 35.

D.23-12-022 prescribed that RECs "generated in 2018," were defined as being banked in 2019. The decision went on to prescribe that RECs banked in or after 2019 should be used first to meet minimum retained RPS compliance targets both for 2024 RPS compliance period and for the 2025 ERRA Forecast that would be filed in May of 2024, pending resolution of SCE's Petition to Modify D.23-06-006. The accounting used a first-in-first-out inventory methodology to determine which RECs would be used first.

Thus, PG&E was following the Commission's directives from the 2024 ERRA Forecast decision, D.23-12-022. It was not making a proposal.

The full quote, from D.23-12-022, p. 17, is shown below:

PG&E proposed to use the most recent vintage RECs in its portfolio for 2024 RPS compliance.

There is a pending petition to modify (PFM) D.23-06-006 focused on the valuation of RECs banked by the investor-owned utilities *in or before 2018*.

We agree that PG&E should use the RECs banked in or after 2019 first.

To ensure that Departing Load customers receive the appropriate valuation of the RECs retired for PG&E's 2024 RPS compliance, however, we direct PG&E to use a First-In-First-Out methodology for RECs banked in or after 2019, beginning with RECs that were generated in 2018.

This methodology should be used for PG&E's 2024 RPS compliance and by PG&E in its 2025 ERRA Forecast application due in May 2024 unless the Commission resolves the PFM in D.23-06-006 prior to its filing.

**PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response**

PG&E Data Request No.:	CalCCA_004-Q006
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_004-Q006
Request Date:	March 6, 2026
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	March 17, 2026
PG&E Witness(es):	Erica Brown – Energy Policy and Procurement

QUESTION 006

Please refer to page 8 of the Joint IOUs' testimony: Confirm that departing load customers do not forfeit their obligation to pay for their share of the costs of RPS-eligible resources they leave behind when they depart bundled IOU service. If not confirmed, please explain.

ANSWER 006

PG&E confirms that departing load customers remain responsible for paying for their share of the above-market costs (i.e., portfolio costs minus the market value as determined by the Commission) of RPS-eligible resources that were procured on their behalf as a bundled service customer but then later depart PG&E for another service provider.

**PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response**

PG&E Data Request No.:	CalCCA_004-Q007
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_004-Q007
Request Date:	March 6, 2026
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	March 17, 2026
PG&E Witness(es):	Erica Brown – Energy Policy and Procurement

QUESTION 007

Please refer to page 9 of the Joint IOUs’ testimony where it states: “Therefore, bundled service customers assumed the entirety of the risk that the forecast market value of the vintaged portfolio was overstated.” Confirm that under the PCIA mechanics in place prior to 2019 it was possible for the forecast market value of the vintaged portfolio to be either overstated or understated.

ANSWER 007

It is theoretically possible that the forecast market value could be over- or under-stated. However, the record in Rulemaking 17-06-026 reflected that the pre-2019 market price benchmark methodologies were “outdated and flawed” and that the price trends using available external data points reflected actual market transactions indicating that the indifference calculation used market price benchmarks that were overstated.

**PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response**

PG&E Data Request No.:	CalCCA_004-Q014
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_004-Q014
Request Date:	March 6, 2026
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	March 17, 2026
PG&E Witness(es):	David Gutierrez – Customer and Enterprise Solutions

QUESTION 014

Please refer to page 29 of the Joint IOUs' testimony: Please quantify the number of departing load customers that returned to PG&E bundled service and then re-departed between 2011 – 2018.

ANSWER 014

PG&E does not have an existing system of record that tracks the number of customers meeting these criteria.

**PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response**

PG&E Data Request No.:	CalCCA_004-Q015
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_004-Q015
Request Date:	March 6, 2026
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	March 17, 2026
PG&E Witness(es):	Erica Brown – Energy Policy and Procurement

QUESTION 015

Please refer to page 29 of the Joint IOUs’ testimony where it states: “This would be an infeasible undertaking, which is why the Commission’s ratemaking process typically does not allocate specific costs and benefits to individual end-use customers but rather to customers on a class or group basis.” Do the Joint IOUs consider Departing Load customers to be individual end-use customers, a class, or a group? Do the Joint IOUs consider each vintage of Departing Load customers to be individual end-use customers, a class, or a group?

ANSWER 015

For PCIA ratemaking purposes, PG&E considers all non-exempt PCIA departing load customers as a group and all bundled service customers as a group where the rules for calculating the PCIA rate for all PCIA non-exempt customers are applied uniformly and across all PABA subaccounts. Further, PCIA rates, by vintage, are calculated at a revenue class level for all non-exempt load and each vintage of non-exempt load has cost obligations that are unique to that vintage.

**PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response**

PG&E Data Request No.:	CalCCA_004-Q029
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_004-Q029
Request Date:	March 6, 2026
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	March 17, 2026
PG&E Witness(es):	Erica Brown – Energy Policy and Procurement

QUESTION 029

Please refer to page 39 of the Joint IOUs’ testimony, where it explains that “PG&E recently adopted an aggressive selling strategy in 2025, selling 2,260 GWh of RPS energy . . . relying on its bank to fill in the compliance short created by these sales.” The testimony continues “This aggressive strategy cannot continue if a non-zero re-valuation of Pre-2019 Banked RECs is ordered and RPS sales present an elevated risk and likelihood of harm to bundled service customers. [Table V-4 omitted] Reductions in supply could also put upward pressure on prices for the remaining available volumes and in turn drive up customer costs, directly for departing load customers and indirectly for bundled service customers through exposure to the RPS MPB via the PCIA-eligible portfolio.”

- a. Please confirm that the RPS MPB is set based on the sale of PCC-1 “index-plus” RECs, and not PCC-2 or PCC-3 RECs.
- b. Please confirm that, by referencing the potential impact of a “reduction[] in supply” on the RPS MPB, PG&E is referring to a possible reduction in supply of PCC-1 RECs that PG&E may sell or offer for sale in the future. If not, please explain.
- c. Please confirm that this possible “reduction[] in supply” referenced would be caused by PG&E choosing to retain more RECs from other sources for RPS compliance purposes, and reducing the amount of Pre-2019 Banked RECs it would use for RPS compliance in that period.

ANSWER 029

- a. In accordance with Ordering Paragraphs 1 and 3 of D.19-10-001, PG&E confirms that the current RPS MPB used for PCIA ratemaking purposes is based on the volume weighted average of all PCC-1 index-plus contracts executed by the IOUs, CCAs, and ESPs within the applicable time periods defined by D.19-10-001 for the applicable PCIA rates.
- b. PG&E refers CalCCA to Section V.B.ii (pp. 35-42) of the Joint IOUs testimony. PG&E confirms that a non-zero re-valuation of Pre-2019 Banked RECs could create

a disincentive to use these banked RECs for bundled service customers' RPS compliance, which could result in a reduction in supply of PCC-1 RECs available to the market.

- c. See PG&E's response to Question 29.b.

Southern California Edison
R.25-02-005 – OIR to Consider ERRA and PCIA Rules and Processes

DATA REQUEST SET C a l C C A - S C E - 0 0 3

To: CalCCA
Prepared by: Eric Lee
Job Title: Sr. Advisor
Received Date: 2/2/2026

Response Date: 2/17/2026

Question 3.1:

Regarding SCE's REC bank, please provide the following:

- a. The quantity of RECs 'deposited' and 'withdrawn' on an annual basis, summarized by the year the RECs were generated since 2010.
- b. The quantity of RECs remaining in the REC bank as of January 1, 2026, summarized by the year the RECs were generated.

Response to Question 3.1:

CONFIDENTIAL

**The Attachment(s) Are Marked Confidential In Accordance With Applicable Law and Regulation.
Basis for Confidentiality In Accompanying Confidentiality Declaration.
Public Disclosure Restricted.**

- a. SCE began banking RECs in 2011, not 2010. See the Confidential Excel Spreadsheet titled "Confidential Banked RECs Tracking 20260101.xlsx" for SCE's Banked RECs position as of January 1, 2026. Reference line "c" for the amount deposited into the bank per year, with positive values representing a deposit and negative values representing a withdrawal. Also note that these are preliminary estimates for 2025 that are subject to further true-up as the final load data is received.
- b. Reference lines "j" and "k" for the remaining Banked RECs by the year the RECs were generated.

Attachment(s) Confidential

Southern California Edison
R.25-02-005 – OIR to Consider ERRA and PCIA Rules and Processes

DATA REQUEST SET C a l C C A - S C E - 0 0 3

To: CalCCA
Prepared by: Eric Lee
Job Title: Sr. Advisor
Received Date: 2/2/2026

Response Date: 2/17/2026

Question 3.9:

Assume SCE's REC bank contains RECs generated and banked from the same RPS-eligible resource prior to 2019 as well as in 2019 or later. For purposes of RPS compliance, is there any difference between the RECs banked prior to 2019 versus the RECs banked in 2019 and later? Please explain.

Response to Question 3.9:

For RPS compliance purposes, there is no difference between RECs banked prior to 2019 and those banked in 2019 or later, provided they meet standard RPS eligibility. Both types of banked RECs may be used to satisfy SCE's RPS obligations.

However, there are important differences from a ratemaking perspective. Under the current PCIA methodology, RECs generated and banked on and after January 1, 2019 have a zero-dollar value applied in the year they are generated. The RPS MPB is only applied if and when those banked RECs are used for bundled compliance. There is then a crediting and debiting methodology that applies specifically to Retained RPS across the ERRA BA and the PABA. Under the prior PCIA methodology, there was no concept of valuing banked RECs based on how or when they were used. Instead, a market value for renewable energy was calculated each year using a forecast volume of renewable energy to be generated in the given year multiplied by an administratively-set weighted average renewable benchmark. That calculated market value was then added to the other forecast value amounts and subtracted from the PCIA-eligible resource and contract costs to set a composite PCIA rate for that year. Any differences between the forecast and actual amounts and costs resulted in over- or under-collections in the ERRA BA that remained solely with bundled service customers.

Additionally, there is a 36-month rolling timeframe where RECs that have been generated can still be sold/transferred to third-parties. Once that time has passed and the REC is banked (retired in WREGIS), the RECs can only be used for SCE's compliance requirements and cannot be transferred to third parties.

Southern California Edison
R.25-02-005 – OIR to Consider ERRA and PCIA Rules and Processes

DATA REQUEST SET C a I C C A - S C E - 0 0 4

To: CalCCA
Prepared by: Eric Lee
Job Title: Sr. Advisor
Received Date: 3/6/2026

Response Date: 3/16/2026

Question 4.04:

Please refer to page 8 of the Joint IOUs' testimony: Confirm that departing load customers do not forfeit their obligation to pay for their share of the costs of RPS-eligible resources they leave behind when they depart bundled IOU service. If not confirmed, please explain.

Response to Question 4.04:

Departing load customers do not forfeit their obligation to pay their share of the above-market costs of RPS-eligible resources. That obligation is implemented annually through the PCIA ratesetting, which is designed to recover the above-market costs of the IOU's portfolio associated with departing load in a given year. The extent to which that obligation is realized depends on the PCIA methodology's calculation of above-market costs, including the assumptions used to determine portfolio market value. To the extent market value is overstated, PCIA charges may not fully reflect actual above-market costs, but that does not negate the underlying obligation of departing load customers to bear their share of those costs.

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Question 4.05:

Please refer to page 9 of the Joint IOUs’ testimony where it states: “Therefore, bundled service customers assumed the entirety of the risk that the forecast market value of the vintaged portfolio was overstated.” Confirm that under the PCIA mechanics in place prior to 2019 it was possible for the forecast market value of the vintaged portfolio to be either overstated or understated.

Response to Question 4.05:

The potential for the forecast market value to have been understated is theoretically possible but unlikely. The record in R.17-06-026 reflects widespread concern that pre-2019 PCIA market price benchmarks overstated realizable portfolio value—thereby suppressing PCIA charges to departing load and exposing bundled customers to PCIA under recovery. The Commission’s adoption of revised benchmarks, a PCIA cap, and other protective reforms, such as a true-up that applied to both bundled service and departing load customers, reflects that the prior framework posed a systematic bundled service customer risk. As D.18-10-019 noted: “This proceeding **corrects an outdated and flawed methodology** for forecast year 2019, and the risk of **substantial and immediate undercollections** using a cap structure **based on the prior methodology** justifies waiting until forecast year 2020 to initiate the cap” (emphasis added).

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To: CalCCA
Prepared by: Eric Lee
Job Title: Sr. Advisor
Received Date: 3/6/2026

Response Date: 3/16/2026

Question 4.13:

Please refer to page 29 of the Joint IOUs' testimony: Please quantify the number of departing load customers that returned to SCE bundled service and then re-departed between 2011 – 2018.

Response to Question 4.13:

This data is not readily available for SCE as it is not in a regularly produced report.

Southern California Edison
R.25-02-005 – OIR to Consider ERRRA and PCIA Rules and Processes

DATA REQUEST SET C a l C C A - S C E - 0 0 4

To: CalCCA
Prepared by: Eric Lee
Job Title: Sr. Advisor
Received Date: 3/6/2026

Response Date: 3/16/2026

Question 4.14:

Please refer to page 29 of the Joint IOUs' testimony where it states: "This would be an infeasible undertaking, which is why the Commission's ratemaking process typically does not allocate specific costs and benefits to individual end-use customers but rather to customers on a class or group basis." Do the Joint IOUs consider Departing Load customers to be individual end-use customers, a class, or a group? Do the Joint IOUs consider each vintage of Departing Load customers to be individual end-use customers, a class, or a group?

Response to Question 4.14:

For PCIA ratemaking purposes, the Joint IOUs do not treat Bundled Service or Departing Load customers as individual end-use customers. Instead, ratemaking is conducted on a group basis. In each year, bundled service customers are treated as one group of customers and are subject to IOU bundled generation rates, while Departing Load customers are treated as a separate group of customers and are subject to vintaged PCIA rates.

**ERRA/PCIA Reform (R.25-02-005) Data Request
California Community Choice Association (CalCCA)
CalCCA-SDGE-DR-003
DATE RECEIVED: February 2, 2026
DATE DUE: February 17, 2026**

QUESTION 3.01

Regarding SDG&E's REC bank, please provide the following:

- a. The quantity of RECs 'deposited' and 'withdrawn' on an annual basis, summarized by the year the RECs were generated since 2010.**
- b. The quantity of RECs remaining in the REC bank as of January 1, 2026, summarized by the year the RECs were generated.**

SDG&E Response:

SDG&E objects to the request for data from 2010 on the following grounds: (i) it would impose an undue burden on SDG&E by requiring it to perform studies, analyses or calculations or to create documents that do not currently exist; and (ii) the request seeks information that is not reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving the foregoing objection, SDG&E responds as follows:

Please see the attached excel file titled "PUBLIC_CalCCA_DR-003_Q 3.01.xlsx".

As reported in SDG&E's Final Renewables Portfolio Standard Procurement Plan in Appendix 1 - RNS

	2011	2012	2013	2014	2015	2016
Risk-Adjusted RECs from Online Generation (GWh)	3,380,204	3,375,730	4,530,598	5,936,403	6,445,310	6,917,982
Withdrawn	(3,328,229)	(3,325,344)	(3,929,669)	(4,239,572)	(4,503,774)	(4,073,691)
Remaining	51,975	50,386	600,929	1,696,831	1,941,536	2,844,291
Non-bankable RECs above the Procurement Quantity Requirement (GWh)	51,975	50,386	31,982	2,099	1,795	901
Existing Banked RECs above the Procurement Quantity Requirement (GWh)	-	-	567,154	1,694,732	1,939,741	2,843,390

2017	2018	2019	2020	2021	2022	2023	2024
6,933,773	6,731,419	6,615,096	6,302,576	6,228,743	6,445,246	6,407,237	6,068,136
(4,217,067)	(4,490,518)	(5,434,058)	(5,449,931)	(4,023,835)	(4,831,796)	(6,232,811)	(6,036,465)
2,716,706	2,240,901	1,181,038	852,645	2,204,908	1,613,450	174,426	31,671
-	-	-	-	-	-	-	-
2,716,706	2,240,901	1,181,038	852,645	2,204,908	1,613,450	174,426	31,671

**CALCCA DATA REQUEST
ERRA/PCIA REFORM (R.25-02-005)
CALCCA-SDGE-DR-004
SDG&E RESPONSE
DATE RECEIVED: March 6, 2026
DATE DUE: March 16, 2026**

QUESTION 4.04

Please refer to page 8 of the Joint IOUs’ testimony: Confirm that departing load customers do not forfeit their obligation to pay for their share of the costs of RPS-eligible resources they leave behind when they depart bundled IOU service. If not confirmed, please explain.

SDG&E Response:

After departing bundled service, departing load customers remain obligated to pay ongoing above-market costs for PCIA-eligible resources through the PCIA rates. These costs are recovered through the PCIA rates in and for the year that the costs are incurred.

**CALCCA DATA REQUEST
ERRA/PCIA REFORM (R.25-02-005)
CALCCA-SDGE-DR-004
SDG&E RESPONSE
DATE RECEIVED: March 6, 2026
DATE DUE: March 16, 2026**

QUESTION 4.05

Please refer to page 9 of the Joint IOUs’ testimony where it states: “Therefore, bundled service customers assumed the entirety of the risk that the forecast market value of the vintaged portfolio was overstated.” Confirm that under the PCIA mechanics in place prior to 2019 it was possible for the forecast market value of the vintaged portfolio to be either overstated or understated.

SDG&E Response:

It is theoretically possible but unlikely that the PCIA mechanics in place prior to 2019 resulted in the forecast market value of the vintaged portfolio being understated.

**CALCCA DATA REQUEST
ERRA/PCIA REFORM (R.25-02-005)
CALCCA-SDGE-DR-004
SDG&E RESPONSE
DATE RECEIVED: March 6, 2026
DATE DUE: March 16, 2026**

QUESTION 4.12

Please refer to page 29 of the Joint IOUs’ testimony: Please quantify the number of departing load customers that returned to SDG&E bundled service and then re-departed between 2011 – 2018.

SDG&E Response:

SDG&E objects to this request on the grounds that it seeks information or documents that are not in the possession, custody or control of SDG&E. Subject to and without waiving the foregoing objection, SDG&E responds as follows:

The customer billing software system that was used during the 2011-2018 period was replaced by a comprehensive new Customer Information System (CIS) billing system in April 2021. At the time the new CIS system was implemented, then-existing customer billing information was converted to the new CIS system format and saved. It is not possible at this point to verify the accuracy or completeness of this historical billing information.

According to the unverified historical billing information that is currently available, during the period 2011 – 2018, 91 departing load customers returned to SDG&E for a period of 30 to 2,524 days, received either standard bundled service or TBS service during this time (it is not possible to determine what portion of these customers were returned to bundled service), and then later re-departed.

**CALCCA DATA REQUEST
ERRA/PCIA REFORM (R.25-02-005)
CALCCA-SDGE-DR-004
SDG&E RESPONSE
DATE RECEIVED: March 6, 2026
DATE DUE: March 16, 2026**

QUESTION 4.13

Please refer to page 29 of the Joint IOUs’ testimony where it states: “This would be an infeasible undertaking, which is why the Commission’s ratemaking process typically does not allocate specific costs and benefits to individual end-use customers but rather to customers on a class or group basis.” Do the Joint IOUs consider Departing Load customers to be individual end-use customers, a class, or a group? Do the Joint IOUs consider each vintage of Departing Load customers to be individual end-use customers, a class, or a group?

SDG&E Response:

Please see Joint IOUs’ Opening Testimony pages 25-27 and 45-48. For PCIA ratemaking purposes, bundled service customers are treated as one group of customers and are subject to IOU bundled generation rates. Departing Load customers are treated as a separate group of customers and are subject to vintaged PCIA rates.

ATTACHMENT B

PG&E Response to CalCCA Data Request 4.01, Confidential Attachment 1

**PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response**

PG&E Data Request No.:	CalCCA_004-Q001
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_004-Q001
Request Date:	March 6, 2026
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	March 17, 2026
PG&E Witness(es):	Erica Brown – Energy Policy and Procurement

QUESTION 001

Please produce the confidential excel workbook marked as CalCCA-21C in PG&E’s 2026 ERRA Forecast Case (A.25-05-011). Note this workbook was originally from PG&E’s 2024 ERRA Compliance Case (A.24-02-012), and that PG&E Witness Ms. Wilson identified the workbook as comprising approximately 400 printed pages on Hearing Tr. 124:24-125:5.

ANSWER 001

An attachment to this response contains CONFIDENTIAL information provided pursuant to the Non-Disclosure Agreement in this proceeding.

See PG&E’s confidential attachment entitled “*ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_004-Q001Atch01CONF.xlsx*” as part of this data request response.

Attachment(s) Confidential



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

FILED

03/25/26

04:59 PM

R1807005

Order Instituting Rulemaking to Consider
New Approaches to Disconnections and
Reconnections to Improve Energy Access
and Contain Costs.

R.18-07-005

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING
COMMENTS ON ASSIGNED COMMISSIONER'S RULING SETTING
WORKSHOP AND ORDERING COMMENTS**

Leanne Bober,
Director of Regulatory Affairs and
Deputy General Counsel
Willie Calvin,
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CALIFORNIA COMMUNITY CHOICE
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March 25, 2026

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SUMMARY OF RECOMMENDATIONS¹

As set forth below, CalCCA respectfully recommends that the Commission:

- Open a successor rulemaking to consider the future of customer protections because it provides an accessible and efficient venue to discuss important issues;
- Maintain the disconnection rate caps and reject the use of disconnections as the primary lever for reducing arrearages because they do not address the underlying issues causing high arrearages and undermine the Commission’s ESJ Action Plan;
- Reject the IOUs’ recommendations to remove the prohibition on collecting deposits because deposits also undermine the Commission’s ESJ Action Plan and are an inefficient method of reducing costs;
- Establish PIPP as a permanent program with the following parameters:
 - Undertake an additional evaluation of PIPP after the four-year implementation period concludes in 2026;
 - Continue allowing customers to participate at the current energy burden thresholds;
 - Coordinate across programs such as the CARE, PIPP, and AMP to provide bill payment assistance and arrearage forgiveness to customers, rather than overhauling the CARE program; and
 - Reject the recommendation to require high-energy usage customers in PIPP to participate in the ESA program unless more data are provided to warrant doing so.
- Establish AMP as a permanent program with the following parameters:
 - Reject the recommendation to require customers to complete CARE post-enrollment verification before AMP enrollment;
 - Modify the proposed time range for customers to have made a bill payment from 24 months to 12 months for eligibility in AMP, rather than to six months;
 - Continue disconnection protections for AMP participants by allowing: (1) partial payments to count towards valid program payments; and (2) valid program payments to offset missed payments before disenrolling customers;

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

Summary of Recommendations continued

- Require IOUs to communicate with customers prior to removing them from AMP, including informing customers of a local CBO they can reach out to for bill assistance;
- Reject the recommendation to adopt a five-year stay-out provision after completing AMP;
- Require IOUs to provide on-bill or online their AMP participation metrics, including the original AMP arrearage, the amount forgiven each month, the amount forgiven to date, and the amount remaining;
- Require IOUs to remind AMP participants one week before the bill due date about the upcoming due date via the customer's desired communication methods; and
- Reject the recommendation to allow IOUs to disconnect customers while in the AMP program, and to rely on individual IOU disconnection thresholds for disconnections while customers are still in AMP.

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

Order Instituting Rulemaking to Consider
New Approaches to Disconnections and
Reconnections to Improve Energy Access
and Contain Costs.

R.18-07-005

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING
COMMENTS ON ASSIGNED COMMISSIONER'S RULING SETTING
WORKSHOP AND ORDERING COMMENTS**

California Community Choice Association² (CalCCA) submits these opening comments pursuant to the *Assigned Commissioner's Ruling Setting Workshop and Ordering Comments*³ (Ruling), dated February 26, 2026. The Ruling seeks comments in response to the questions set out in this ruling and the information discussed during the workshop (Workshop).

I. INTRODUCTION

Californians are struggling to pay energy bills amidst an affordability crisis. This is made clear, in part, by the consistent, elevated levels of arrearages across the investor-owned utilities (IOU).⁴ This proceeding, which originally opened to reduce disconnections,⁵ is now addressing the balance between disconnections and arrearages, as well as testing pilot programs such as 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 *Assigned Commissioner's Ruling Setting Workshop and Ordering Comments*, Rulemaking (R.) 18-07-005 (Feb. 26, 2026).

⁴ See Ruling, at 5 (noting that the level of arrearages has grown from \$418.5 million in October of 2018, to fluctuating between \$1.7 billion to over \$2.5 billion since November 2023).

⁵ See *Order Instituting Rulemaking*, R.18-07-005 (July 12, 2018), at 1.

Percentage of Income Payment Plan (PIPP) pilot and the Arrearage Management Plan (AMP) pilot. After eight years, this proceeding faces numerous open questions and issues with the AMP pilot scheduled to sunset on October 1, 2026, the PIPP pilot scheduled to sunset in February 2027, and the proceeding itself facing an impending statutory deadline of December 31, 2026. The Ruling asks over 40 questions related to disconnection rate caps, AMP, PIPP, the Community-Based Organization (CBO) pilot, ongoing support for customers at risk of disconnections, and where future discussions and additional public processes can address these issues.⁶ Given the volume of remaining issues that require substantive discussions among stakeholders, the most reasonable and efficient method to address questions of venue and future processes is to open a successor rulemaking that addresses ongoing and future customer protections.

As the last remaining topic scoped into Phase 3 of this proceeding, the Ruling asks questions specifically about IOU disconnection caps and makes clear that there are concerns with removing or raising the disconnection caps and with maintaining them at current levels.⁷ Workshop presentations from the California Public Utilities Commission (Commission) and IOUs emphasized continuing high levels of arrearages, and the IOUs provided estimated effects of increasing the volume of disconnections in reducing arrearages. A conclusion from those IOU presentations is that disconnections are the primary lever for managing arrearages. Not only does this conclusion ignore the true cost drivers of high rates, and therefore, the true drivers of arrearages, but it also ignores empirical findings that disconnections disproportionately impact customers that the Commission explicitly targets to support in its Environmental and Social

⁶ Ruling, at 8-17. At least 17 Ruling questions relate to activities that either require more time than is remaining in this proceeding to adequately and publicly discuss, or that require reacting to results of future reports that would occur after December 31, 2026.

⁷ Ruling, at 7-9.

Justice (ESJ) Action Plan.⁸ The Commission should maintain the disconnection rate caps, and disconnections should not be viewed as the primary tool for reducing arrearages, as they are inefficient at reducing arrearages and are inequitable.

The same rationale applies to Pacific Gas and Electric Company's (PG&E), Southern California Edison Company's (SCE), and Southern California Gas Company's (SoCalGas) recommendations at the Workshop to remove the prohibition of deposits.⁹ The Commission's stance on deposits should not change from what was established in Decision (D.) 20-06-003, that deposits and re-establishment deposits can create financial hurdles for residential customers and the Commission should reduce financial burdens caused by deposits.¹⁰

The Ruling also asks questions regarding the CBO pilot, AMP, and PIPP, and the possible future iterations of those programs.¹¹ In response to these questions, CalCCA reiterates its Opening Comments¹² to the October 13, 2025, *E-Mail Ruling on Arrearage Related Assistance Program* (ARAP Ruling),¹³ which asks similar questions about the future of these pilots. While CalCCA does not have feedback on the CBO pilot at this time, as no participating zip codes are in community choice aggregator service areas, it recommends that AMP and PIPP be established as permanent programs to continue providing support to low-income customers, as detailed in its ARAP Comments.

As set forth below, CalCCA respectfully recommends that the Commission:

⁸ California Public Utilities Commission, *CPUC Environmental & Social Justice Action Plan* (Apr. 7, 2022) (ESJ Action Plan).

⁹ Workshop Slides, at 30, 36, 44.

¹⁰ D.20-06-003, *Phase I Decision Adopting Rules and Policy Changes to Reduce Residential Customer Disconnections for the Larger California-Jurisdictional Energy Utilities*, R.18-05-005 (June 11, 2020), at 140, Conclusion of Law 7 and 8.

¹¹ Ruling at 9-13.

¹² *California Community Choice Association's Opening Comments on E-Mail Ruling on Arrearage-Related Assistance Programs* (CalCCA ARAP Comments), R.18-07-005 (Nov. 14, 2025).

¹³ *E-Mail Ruling on Arrearage Related Assistance Program*, R.18-07-005 (Oct. 13, 2025), at 5-7.

- Open a successor rulemaking to consider the future of customer protections to provide an accessible and efficient venue to discuss these important issues;
- Maintain the disconnection rate caps and reject the use of disconnections as the primary lever for reducing arrearages because disconnecting customers does not address the underlying issues causing high arrearages and undermines the Commission’s ESJ Action Plan;
- Reject the IOUs’ recommendations to remove the prohibition on collecting deposits because deposits also undermine the Commission’s ESJ Action Plan and are an inefficient method of reducing costs;
- Establish PIPP as a permanent program with the following parameters:
 - Undertake an additional evaluation of PIPP after the four-year implementation period concludes in 2026;
 - Continue allowing customers to participate at the current energy burden thresholds;
 - Coordinate across programs such as the California Alternative Rate for Energy (CARE), PIPP, and AMP to provide bill payment assistance and arrearage forgiveness to customers, rather than singularly overhauling the CARE program; and
 - Reject the PIPP Evaluation recommendation to require high-energy usage customers in PIPP to participate in the Energy Savings Assistance (ESA) program unless more data are provided to warrant doing so.¹⁴
- Establish AMP as a permanent program with the following parameters:
 - Reject the recommendation to require customers to complete CARE post-enrollment verification before AMP enrollment because it would add unnecessary administrative burden on customers;¹⁵
 - Reduce the bill payment requirement for eligibility in AMP from 24 months to 12 months, rather than the six months recommended by the AMP Evaluation;¹⁶

¹⁴ *Percentage of Income Payment Plan Pilot Program Final Evaluation Report* (PIPP Evaluation), R.18-07-005 (Mar. 17, 2025), Attachment A, at 80 (recommending mandatory participation in ESA for high-energy usage customers).

¹⁵ *Arrearage Management Plan Final Evaluation Report* (AMP Evaluation), R.18-07-005 (Oct. 1, 2025), at 103 (describing the rationale for Recommendation 2 that customers should be required to enroll in CARE or FERA prior to being enrolled in AMP).

¹⁶ *Id.* at 11 (listing the IOU staff recommendation to reduce the window for past payments from 24 months to six months or 12 months).

- Continue disconnection protections for AMP participants by allowing: (1) partial payments to count towards valid program payments; and (2) valid program payments to offset missed payments before disenrolling customers;
- Require IOUs to communicate with customers prior to removing them from AMP, including informing customers of local CBOs available for bill assistance;
- Reject the AMP Evaluation recommendation to adopt a five-year stay-out provision after completing AMP;¹⁷
- Require IOUs to provide customers with on-bill or online AMP participation metrics, including the original AMP arrearage, the amount forgiven each month, the amount forgiven to date, and the amount remaining;
- Require IOUs to send a payment reminder to AMP participants one week prior to a bill due date via the customer’s desired communication methods; and
- Reject the AMP Evaluation recommendation to allow IOUs to disconnect customers participating in AMP, and to instead rely on individual IOU disconnection thresholds for disconnections for AMP customers.¹⁸

II. A SUCCESSOR RULEMAKING SHOULD BE OPENED TO CONSIDER THE FUTURE OF CUSTOMER DISCONNECTION PROTECTIONS AND ARREARAGE REDUCTIONS

The most efficient and reasonable way to adequately address the difficult questions and issues remaining in this proceeding is to open a successor rulemaking. This proceeding has accomplished much in the eight years it has been open, but as evidenced by the volume of questions in the Ruling, there is still much to discuss. Numerous questions in the Ruling ask about venues, processes, or other considerations related to customer protections that may be available beyond the current statutory deadline of this proceeding of December 31, 2026.¹⁹

¹⁷ *Id.* at 103-104 (stating that a five-year stay-out provision will ensure customers have reestablished good payment patterns and are only re-entering AMP after facing additional hardship).

¹⁸ *Id.* at 103 (recommending customers be disconnected when AMP unenrollment criteria are met).

¹⁹ CalCCA considers at least 17 questions in the Ruling to relate to activities that either require more time than is remaining to adequately and publicly discuss, or that require reacting to results of future reports that will occur after December 31, 2026.

Additionally, an entire section of the Ruling asks questions about the future of ongoing support for customers at risk of disconnections and where discussions should happen.²⁰ The most reasonable and efficient method to facilitate continued discussions, process development, and program modifications and development is to open a successor rulemaking.

This proceeding opened in response to SB 598, which ordered the Commission to develop policies, rules, or regulations to reduce disconnections due to nonpayment by residential customers by January 1, 2024.²¹ While the COVID-19 pandemic interrupted progress towards reducing arrearages, it provided further disconnection protections through a moratorium.²² As Californians face the realities of a post-COVID world, arrearages remain high, and disconnection rate caps have decreased.²³ Customers face a different environment now than when this proceeding was opened, but many similar challenges remain. At the core of these challenges are public health and difficult economic realities, exacerbated by ever-increasing electricity rates. Additionally, the recent closure of the Affordability Rulemaking, R.18-07-006, means parties lack a dedicated forum to coordinate and focus on these issues.²⁴ There are also many program recommendations circulating from parties for AMP, PIPP, and the CBO Pilot, all of which must be given sufficient discussion. For example, PG&E recommends removing payment allowances,²⁵ which are an aspect of AMP. This is not a recommendation the AMP Evaluation

²⁰ Ruling, at 16-17 (discussing questions related to ongoing support for customers at risk of disconnection).

²¹ Senate Bill 598 (SB 598) (Hueso 2017, Ch. 362, Stats. 2017).

²² Resolution M-4842, *Emergency Authorization and Order Directing Utilities to Implement Emergency Customer Protections to Support California Customers During the COVID-19 Pandemic*, Executive Division (Apr. 16, 2020).

²³ See, e.g., Workshop Slides, at Slide 32 (depicting PG&E's timeline of arrearages labeled with decreasing disconnection rate caps over time).

²⁴ D.25-12-044, *Decision Updating the Affordability Framework and Closing Proceeding* (Dec. 18, 2025).

²⁵ See Workshop Slides, at Slide 35.

considers, and therefore, parties do not have data to support the recommendation, nor have parties had much time to consider its customer impact. Rather than prematurely adopting program recommendations now, a successor proceeding would allow for more robust discussion of program changes for customer protections to ensure programs are optimized. The Commission should therefore plan to open a new rulemaking to continue to address customer protections in the context of disconnections, affordability, and arrearages. Rather than fracturing these related discussions into siloes, a new rulemaking will allow for a robust record to be developed in an efficient way and in a single venue.

III. THE DISCONNECTION RATE CAPS SHOULD BE MAINTAINED AND DISCONNECTIONS SHOULD NOT BE USED AS THE PRIMARY LEVER TO ADDRESS ARREARAGES BECAUSE THEY FAIL TO ADDRESS THE CONTRIBUTING UNDERLYING CAUSES OF UNPAID BILLS AND UNDERMINE THE ESJ ACTION PLAN

The Commission and stakeholders should not view disconnecting customers as the primary lever for reducing arrearages. Presentations from PG&E, SCE, SoCalGas, and San Diego Gas & Electric Company supporting the increase and/or removal of disconnection caps all assert an inherent correlation between increased disconnection rates and reductions in arrearages.²⁶ While a correlation may exist, additional data is required to make that conclusion. If any such correlation is considered in isolation, it ignores the real public health, safety, and economic impacts to customers and communities from disconnections that must be considered and acknowledged before any changes to increase or remove disconnection rate caps are made.

There are two primary reasons why disconnections are not a desirable tool for managing arrearages. *First*, disconnections disproportionately impact Black and Latino households and families with young children, even when controlling for income, energy costs, and housing

²⁶ *Id.* at Slides 27, 33, 43, 50.

conditions.²⁷ Disconnections are also positively correlated with low-income families, disabled residents, and renters.²⁸ Plowing ahead with increases or removal of disconnection caps to address arrearages would therefore ignore empirical findings that disconnections disproportionately impact vulnerable and underrepresented communities. The Commission has actively acknowledged the need to protect these communities as stated in the Commission’s ESJ Action Plan.²⁹ Increasing or removing disconnection caps would directly conflict with the Commission’s ESJ Action Plan and could reverse its past work to reduce disconnections and current work to provide support to ESJ communities.

Second, any correlation between increased disconnections and reductions in arrearages does not address the underlying issue contributing to elevated arrearages: high electricity rates due to high costs. While holding high levels of arrearages can put upward pressure on rates through socializing uncollectibles across ratepayers, the added holding cost is modest compared to other utility costs. The Commission has consistently found in the last several years that the primary cost drivers for utility rates are wildfire-related costs, rooftop solar-related costs, and higher investment in distribution infrastructure.³⁰ The risk of disconnection does not help customers pay high electricity rates. Instead, it forces them to prioritize their utility bill over other necessities or even to resort to high-interest-rate payday loans.³¹

²⁷ Nature Communications, *Assessing Demographic Vulnerability and Weather Impacts on Utility Disconnections in California*, Trevor Memmott, David M. Konisky, and Sanya Carley (Apr 17, 2024), at 6.

²⁸ California Public Utilities Commission, *Report on Residential and Household Utility Service Disconnections Pursuant to Public Utilities Code Section 910.5* (Apr. 1, 2024), at 11.

²⁹ ESJ Action Plan, at 2 (describing ESJ communities as predominantly communities of color or low-income communities that are underrepresented in the policy setting or decision-making process, subject to a disproportionate impact from one or more environmental hazards, and are likely to experience disparate implementation of environmental regulations and socioeconomic investments in their communities).

³⁰ California Public Utilities Commission, *2025 Senate Bill 695 Report* (Sept. 2025), at 2-3 (describing the three primary drivers of increased costs).

³¹ Parties, including The Utility Reform Network, mentioned these possibilities during the Workshop.

IOU presentations at the Workshop, on the other hand, emphasized arrearage reductions resulting from disconnections. For example, PG&E estimated that a one percentage point increase in its disconnection rate cap would reduce arrearages by \$88 million and SCE estimated that the same cap increase would reduce arrearages by \$27 million.³² To put this into perspective, PG&E's estimate would involve disconnecting 56,746 customers to achieve the reduction it cites.³³ Even taking the assumption that a \$27 million decrease in arrearages directly lowers revenue requirement by \$27 million for all customers, this represents less than two thousandths of PG&E's latest General Rate Case revenue requirement for 2027 of \$16.6 billion.³⁴ Interrupting the lives of over 50,000 additional customers for this modest reduction in costs is unreasonable, especially given the demographics more heavily impacted by disconnections. Without reducing more significant utility costs, customers who are disconnected will face the same high rates that led them to get behind on bills in the first place, even if they are reconnected within a short period of time. Disconnections exacerbate existing equity issues and do not address the root cause of customers' increasing arrearages, and therefore, should not be considered a primary lever for managing arrearages.

IV. THE COMMISSION SHOULD REJECT IOU RECOMMENDATIONS TO REMOVE THE PROHIBITION ON RESIDENTIAL CUSTOMER DEPOSITS TO AVOID UNNECESSARY FINANCIAL BURDENS

Recommendations from the IOUs to reinstate customer deposits impose unnecessary financial burdens on customers without an equivalent benefit to all customers. PG&E, SCE, and SoCalGas recommended at the Workshop to remove the prohibition on residential customer

³² *Id.* at slide 27.

³³ *Id.* at 33 (calculating the difference between 198,611 customer disconnections associated with PG&E's current cap of 3.5 percent and 255,357 disconnections associated with a 4.5 percent disconnection cap).

³⁴ *2027 General Rate Case Application of Pacific Gas and Electric Company*, A.25-05-009 (May 15, 2025), at 22, Table 1.

deposits as a means to reduce arrearages.³⁵ SCE even identifies this prohibition on deposits as a “policy gap.”³⁶ To the contrary, the Commission has been clear on its view of residential customer deposits and has established the prohibition as a policy. In D.20-06-003, the Commission explains that deposits create financial hurdles for residential customers and that it should take action to reduce the financial burdens of deposits.³⁷ The Decision operationalizes this view by prohibiting deposits for new service and for the reestablishment of service.³⁸ The same rationale described above applies to deposits, especially those for reestablishing service: deposits undermine the Commission’s ESJ Action Plan goals and do not provide an efficient means of reducing arrearages compared to addressing larger cost drivers. Therefore, the Commission should reject the IOUs’ recommendations to reinstate customer deposits.

V. PIPP SHOULD BE PERMANENTLY ADOPTED TO ENSURE THE CONTINUED SUPPORT TO LOW-INCOME CUSTOMERS

As CalCCA recommended in its Opening Comments to the ARAP Ruling, the Commission should establish PIPP as a permanent program to continue providing support to low-income customers.³⁹ Additionally, as recommended and explained in the CalCCA ARAP Comments, the Commission should:

- Undertake an additional evaluation of PIPP after the four-year implementation period concludes in 2026;
- Continue allowing customers to participate at the current energy burden thresholds;
- Coordinate across programs such as the CARE, PIPP, and AMP to provide bill payment assistance and arrearage forgiveness to customers, rather than singularly overhauling the CARE program; and

³⁵ Workshop Slides, at 36; *see also Id.* at 30; *see also Id.* at 44.

³⁶ *Id.* at 30.

³⁷ D.20-06-003, at 140, COL 7 and 8.

³⁸ *Id.* at 147, OP 8 and 9.

³⁹ CalCCA ARAP Comments, at 3.

- Reject the PIPP Evaluation recommendation to require high-energy usage customers in PIPP to participate in the ESA program unless more data is provided to warrant doing so.⁴⁰

VI. AMP SHOULD BE PERMANENTLY ADOPTED TO ENSURE CUSTOMERS CONTINUE RECEIVING SUPPORT IN PAYING DOWN ARREARAGES

As CalCCA recommended in its ARAP Comments, the Commission should also establish AMP as a permanent program to continue providing customers with support in managing arrearages.⁴¹ Additionally, as recommended and explained in the ARAP Comments, the Commission should:

- Reject the recommendation to require customers to complete CARE post-enrollment verification before AMP enrollment because it would add unnecessary administrative burden on customers;⁴²
- Reduce the bill payment requirement for eligibility in AMP from 24 months to 12 months, rather than the six months recommended by the AMP Evaluation;⁴³
- Continue disconnection protections for AMP participants by allowing: (1) partial payments to count towards valid program payments; and (2) valid program payments to offset missed payments before disenrolling customers;
- Reject suggestions to eliminate the missed payments allowance or to reduce the number of allowed missed payments;
- Require IOUs to communicate with customers prior to removing them from AMP, including informing customers of local CBOs available for bill assistance;
- Reject the AMP Evaluation recommendation to adopt a five-year stay-out provision after completing AMP;⁴⁴

⁴⁰ PIPP Evaluation, Attachment A, at 80 (recommending mandatory participation in ESA for high-energy usage customers).

⁴¹ *Ibid.*

⁴² AMP Evaluation, at 103 (describing the rationale for Recommendation 2 that customers should be required to enroll in CARE or FERA prior to being enrolled in AMP).

⁴³ *Id.* at 11 (listing the IOU staff recommendation to reduce the window for past payments from 24 months to six months or 12 months).

⁴⁴ *Id.* at 103-104 (stating that a five-year stay-out provision will ensure customers have reestablished good payment patterns and are only re-entering AMP after facing additional hardship).

- Require IOUs to provide customers with on-bill or online AMP participation metrics, including the original AMP arrearage, the amount forgiven each month, the amount forgiven to date, and the amount remaining;
- Require IOUs to send a payment reminder to AMP participants one week prior to a bill due date via the customer's desired communication methods; and
- Reject the AMP Evaluation recommendation to allow IOUs to disconnect customers participating in AMP, and to instead rely on individual IOU disconnection thresholds for disconnections for AMP customers.⁴⁵

VII. CALCCA RESPONSES TO COMMENTS SET OUT IN THE RULING

2. Discussion Questions - Disconnections Caps

- **If the Commission were to modify the disconnection caps, what steps should it take to mitigate the party concerns discussed above? Present as detailed a proposal as you are able.**

The Commission should not modify disconnection rate caps at this time. See Section 3, above.

- **If the Commission were to modify the disconnections caps, what adjustment should be made? Specifically, should the Commission increase or decrease the caps, and if so, by what amount?**

The Commission should not modify disconnection rate caps at this time. See Section 3, above.

- **Provide any other comments or recommendations as to how the Commission should address lifting the caps, increasing the caps, or leaving the caps at current levels.**

The Commission should not modify disconnection rate caps at this time. See Section 3, above.

⁴⁵ *Id.* at 103 (recommending customers be disconnected when AMP unenrollment criteria are met).

- **If the Commission raised the disconnection caps, what mechanisms should the Commission implement to control unintended consequences, such as rapid spikes in disconnections without adequate notice or engagement of customers, disconnections of customers making good faith efforts to pay off especially burdensome arrearages, unreasonable use of disconnections to compel payment of amounts that are relatively inconsequential to overall arrearage levels, or heavy concentration of disconnections in specific or vulnerable communities?**

The Commission should not modify disconnection rate caps at this time. See Section 3, above.

- **Should the Commission create a process for the IOUs to seek authorization to raise caps by a specific amount so that there is an opportunity for comment and deliberation? If so, what should that process be?**

The Commission should not modify disconnection rate caps at this time. See Section 3, above.

- **How should any such process incorporate public input, updated data, and implementation experience into its understanding of whether the caps are set at an appropriate level or should be raised or lowered?**

The Commission should not modify disconnection rate caps at this time, but a successor rulemaking could be a venue to incorporate public input and updated data. See Sections 2 and 3, above.

- **Should the Commission establish “circuit breaker” conditions that would pause or reverse an increase in the disconnection caps? If so, what specific factors should trigger a “circuit breaker” and how should a halt or reversal be implemented or removed once the “circuit breaker” condition is resolved?**

The Commission should not modify disconnection rate caps at this time. See Section 3, above.

- **Some parties have argued that the prohibition on disconnecting more than 30 percent of customers in a ZIP code functionally bans disconnection in low-population ZIP codes.**
 - **Is it reasonable to remove this restriction for populations with fewer than 100 customers? If not, what should the Commission do to preserve the intent of this protection while addressing party concerns about its functional workability in areas with low population density?**

No. The Commission should not modify disconnection rate caps at this time. See Section 3, above.

- **Are there other mechanisms or data sources the Commission should utilize to prevent disconnection “hotspots” from emerging in low-population vulnerable communities without inadvertently prohibiting disconnections only in areas with low population density?**

The Commission should not modify disconnection rate caps at this time. See Section 3, above.

- **Is there a risk of minimizing the public health, economic, or social impacts on vulnerable communities that become “hotspots” of disconnections? If so, how should the Commission minimize and mitigate those impacts?**

Yes. See Section 3, above.

3. Discussion Questions - Community Based Organization Pilot Program (CBO Pilot)

- **What are the merits/concerns of the advice letter process referenced above?**

CalCCA has no comments on the CBO Pilot at this time.

- **How should the Commission incorporate lessons learned through the evaluation of the CBO pilot if this proceeding were closed?**

CalCCA has no comments on the CBO Pilot at this time.

- **Should the pilot’s sunset date be extended to enable more data collection and comprehensive evaluation of the pilot’s effectiveness?**

CalCCA has no comments on the CBO Pilot at this time.

- **Should the Commission consider lessons learned through this pilot in other proceedings or ongoing activities? If so what other proceedings should be considered?**

The Commission should consider lessons learned through the pilot in a successor proceeding discussing customer protections. See Section 2, above.

- **If the lessons learned are to be evaluated and considered after this proceeding closes, what proceeding should the evaluation be conducted through? For instance, should the evaluation be considered in Application (A.) 25-06-022, A.26-01-003, or another proceeding?**

The Commission should consider lessons learned through the pilot in a successor proceeding discussing customer protections. See Section 2, above.

4. Discussion Questions - Arrearage Management Program (AMP)

- **Should the Commission extend AMP’s sunset date or allow it to expire on October 1, 2026?**

The Commission should establish AMP as a permanent program to continue providing arrearage management support to low-income customers. See Section 5, above.

- **If the program is allowed to expire, what if any other provisions or safeguards should the Commission consider for customers at risk of disconnection?**

The Commission should work to keep continuity for customers in AMP between the pilot and a permanent version of the program. See Section 5, above.

- **If the program is allowed to continue beyond the current expiration date, should the Commission make the following program modifications set out in the evaluation report and/or recommended by parties that could affect program effectiveness, total program costs, and program complexity? If so, discuss how and why.**
 - **Adopting the evaluation report’s suggestion to require customers who apply for AMP to complete a post enrollment verification of CARE/FERA status and to remove ineligible customers after verification.**

No. See Section 5, above.

- **Adopting the evaluation report’s recommendation to require disconnection and disenrollment of AMP participants who miss payments, rather than just removal from AMP.**

No. See Section 5, above.

- **Adopting the evaluation report’s recommendation to require the IOUs to send communications to a customer before they are involuntarily removed from AMP with information on available resources. What information should these communications provide?**

Yes. See Section 5, above.

- **Adopting the evaluation report’s recommendation to limit AMP reenrollment to after five years.**

No. See Section 5, above.

- **Adopting the evaluation report’s recommendation to require the IOUs to include an AMP specific insert in customer bills that contains specific information about AMP progress. What information should this bill insert contain?**

Yes. See Section 5, above.

- **Adopting the evaluation report’s recommendation to require the IOUs to remind AMP customers about their upcoming bill one week prior to the due date or if there is a missed payment. How should these notifications be provided, and what information should they contain?**

Yes. See Section 5, above.

- **Adopting the evaluation report’s recommendation to change AMP eligibility requirements to a payment made in the last 24 months, or some other time period.**

No. See Section 5, above.

- **Adopting the party recommendation to provide different options to customers who make a partial payment compared to the options provided to those who make no payment at all?**

Yes. See Section 5, above.

- **Adopting California Community Choice Association’s (CalCCA’s) recommendation to require the IOUs to provide on-bill or online each participant’s AMP information, such as:**
 - **original AMP arrearage,**
 - **the amount forgiven each month,**
 - **the amount forgiven to date, and**
 - **the amount remaining.**

Yes. See Section 5, above.

- **Adopting the Joint Consumers’ recommendation to conduct another evaluation of AMP in 5 years, especially if there are substantial program design changes adopted now.**

Yes. See Section 5, above.

- **Adopting SCE’s recommendation to reduce the AMP forgiveness thresholds from \$8,000 to \$4,000 to promote affordability for all customers.**

No. AMP is designed to scale its forgiveness to the level needed by participants and to provide a large enough forgiveness ceiling is important for actually allowing customers to get the benefit of forgiving all their arrearages to provide a fresh start and continue to pay bills on time.

5. Discussions Questions - Percentage of Income Pilot Program (PIPP)

- **Should the Commission extend PIPP’s sunset date or let it expire on February 1, 2027?**

The Commission should establish PIPP as a permanent program to continue providing bill assistance to low-income customers. See Section 4, above.

- **If the program expires as currently set, should the Commission take action to minimize the risk of disconnecting current participants? If so, how?**

The Commission should not let PIPP expire and should work to provide continuity from the pilot to a permanent version. See Section 4, above.

- **If recommending that the program continue, discuss how the following program modifications proposed by parties and in the PIPP evaluation report could affect program effectiveness, total program costs, and program complexity.**
 - **Limiting eligibility for PIPP to certain customers to mitigate cost impacts and target the program’s benefits to customers with the greatest demonstrated need.**

No. See Section 4, above.

- **Which subset of customers should the IOUs target for enrollment? Why?**

The IOUs should continue to target the low-income customers, such as those on CARE.

- **Would limiting eligibility to these customers mitigate costs enough to justify continuation of the program?**

Providing bill assistance to PIPP participants is justification for continuing the program.

See Section 4, above.

- **Are there other options to mitigate costs while retaining PIPP in some form for customers with demonstrated need for the program?**

Primary cost drivers as identified by the Commission should be reduced to lower rates for all customers. See Section 3, above.

- **Should the Commission extend the PIPP sunset date? If so, what should be the new sunset date?**

The Commission need not extend the sunset date if it plans to establish a permanent version of PIPP. See Section 4, above.

- **If the Commission extends the PIPP sunset date, should the Commission order an updated evaluation in order to understand the effects of these changes on participant benefits, participant behavior, and total program costs?**

An updated evaluation is prudent, regardless of a permanent or extended version of PIPP. See Section 4, above.

- **Should the Commission consider a limited continuation of the program that services existing participants until they are able to leave the program without adding additional participants?**

At bare minimum, those receiving support should continue to receive it until they are no longer eligible. However, the Commission should establish a permanent version of PIPP as described in Section 4, above.

6. Discussion Questions: Ongoing Support for Customers at Risk of Disconnection

- **Should the Commission order an ongoing process or working group to consider and develop best practices to address factors that increase risk of disconnection or limit reconnections?**

The Commission should establish a successor rulemaking to discuss customer protections related to disconnections, arrearages, and affordability. See Section 2, above.

- **If so, describe implementation recommendations for such process and scope of issues for any recommended working group to address. •**

In a successor proceeding, the Commission can follow standard processes for scope and discussions. See Section 2, above.

- **If the Commission ordered an ongoing process or working group, what entities should be included in that process or working group?**

The Commission should include parties that respond to a successor rulemaking's Order Instituting Rulemaking (OIR) and those that motion for party status. Mailing of the OIR should be provided to the service lists of R.18-07-005 and the Affordability proceeding, R.18-07-006.

- **For example, should the Commission look to legislative direction of Pub. Util. Code Section 718(a) to convene stakeholders such as public health officials, consumer advocates, and organizations representing low-income communities, or should the Commission consider additional entities beyond those identified in statute?**

In a successor rulemaking, the Commission can plan workshops and invite public health officials, consumer advocates, and organizations representing low-income communities as it has for previous workshops in this proceeding.

- **Are there any existing working groups or other ongoing processes for which these items would be reasonable additions to existing work?**

CalCCA has no comment at this time.

- **What is/are the appropriate venue(s) where these issues could be considered on an ongoing basis when this proceeding is closed?**

The most reasonable venue is a successor rulemaking. See Section 2, above.

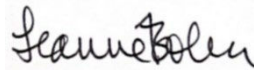
- **For example, should these issues be considered in A.25-06-022,21 A.26-01-003, Rulemaking 25-07-013, specific phases of individual General Rate Cases, procedural vehicles complying with the Commission’s direction to propose demand flexibility rates for all customer classes, or a non-proceeding venue such as an interagency summit or en banc Commission meeting?**

The most reasonable venue is a successor rulemaking. See Section 2, above.

VIII. CONCLUSION

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

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

March 25, 2026



Comments on Mar 13 meeting discussion and Track 1 Straw Proposal and Track 2 Issue Paper

Initiative: Demand and distributed energy market integration

Comment period

Mar 13, 2026, 08:30 am - Mar 27, 2026, 05:00 pm

Submitting organizations

California Community Choice Association

California Community Choice Association

Submitted on 03/27/2026, 04:57 pm

Contact

Jennifer Baak (jennifer@cal-cca.org)

1. Please provide your organization's feedback on the DDEMI meeting discussion on March 13, 2026 and "Demand and Distributed Energy Market Integration Track 1: Straw Proposal: Reflecting End-User Exports in Demand Response and Track 2: Demand Flexibility Enhancements" paper.

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the Demand and Distributed Energy Market Integration (DDEMI) Track 1 Straw Proposal and Track 2 Issue Paper. CalCCA supports the Track 1 Straw Proposal to allow exports from individual customer meters under the modified Proxy Demand Response (mPDR) construct, with the following clarifications:

The mPDR model should be available under all applicable Performance Evaluation Methodologies (PEM);

The DR Providers (DRP) should determine how to allocate exports across customers participating in the aggregation;

DRPs should be able to create aggregations consisting of exporting and non-exporting Demand Response (DR) and distributed energy resources (DER) within a sub-load aggregation point (sub-LAP), to maximize exported energy; and

Individual customer resources that are capable of exporting energy will interconnect using a Rule 21 export agreement.

CalCCA does not yet take a position on the Track 2 Issue Paper. Before taking a position, CalCCA requires additional information about the applicability and details of the Issue Paper. The California Independent System Operator (CAISO) should therefore modify the Issue Paper to:

Clarify that the large loads topic applies to both resources within the CAISO Balancing Area

Authority (BAA), as well as those in non-CAISO BAAs;

Consider how large loads with DR capability located in the CAISO BAA should be modeled to ensure their demand reduction capabilities are accurately represented; and

Clarify how the DDEMI stakeholder process and the Large Loads stakeholder process interact.

Finally, CalCCA recommends modifications to the Coordination Framework and DDEMI Scoping Issues topics in the Track 2 Issue Paper. In summary, the CAISO should:

Include community choice aggregator (CCA) representatives in its coordination framework efforts, since CCAs comprise roughly one-third of the CAISO load and manage significant DR and DERs via their customer programs;

Clarify what it considers to be 'flexible load' in the context of the near-term proposal, scheduled to be addressed in the third quarter of 2026; and

Modify the Straw Proposal and Issue Paper to include a discussion of device-level measurement, which was discussed at length during the 2025 DDEMI Working Group (WG) efforts in 2025 but was not addressed in the Straw Proposal or Issue Paper.

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

CalCCA supports the Track 1 Straw Proposal's mPDR model to enable exports from the individual customer meter, with clarifications discussed in responses to questions 3, 4, and 5. The mPDR framework would provide DRPs with incentives to create aggregations to maximize exports within each sub-LAP. The Straw Proposal would modify PEMs to allow individual resources, subject to their Rule 21 export agreements, to receive credit for exports that would otherwise be zeroed out under the current PDR framework. The mPDR would allow cumulative exports up to the total load of the entire aggregation and encourage DRPs to create portfolios of exporting and non-exporting resources to maximize net export credits.

Allowing PDR exports will accurately reflect resource capabilities, minimize barriers to participation, and offer both reliability and cost-efficiency benefits. Expanding the pool of dependable capacity using the mPDR model will provide additional reliability during times of system stress and improve price formation by increasing the amount of demand that can respond to market price signals. The mPDR model would also enable a pathway for CCAs and other load-serving entities (LSE) to receive resource adequacy (RA) credit for the additional energy exported, thereby lowering customer costs.^[1]

[1] In the CPUC's recently opened DR (R.25-09-004) and RA (R.25-10-003) proceedings, in which many stakeholders, including CalCCA, asked the CPUC to develop a qualifying capacity (QC) methodology for PDRs capable of exports. RA participation necessitates both a QC methodology and a market participation model. The CAISO and CPUC should coordinate to ensure that both entities address the issues within their separate jurisdictional responsibilities, thereby supporting full RA and energy market participation of PDRs with export capabilities. See *California Community Choice Association's Reply Comments on the Order Instituting Rulemaking to Enhance Demand Response in California*, Rulemaking (R.) 25-09-004 (Dec. 1, 2025), at 11-12: <https://cal-cca.org/wp-content/uploads/2025/12/Reply-Comments-on-the-OIR-to-Enhance-Demand-Response-in-California-12-01-25.pdf>.

3. Should the change in the straw proposal apply to all PEMs or be limited to MGO? Why or why not?

The Straw Proposal to allow exports from individual customer resources, up to the total load of each DRP's sub-LAP aggregation, should apply to *all* PEMs and not be limited to the Meter Generator Output (MGO) PEM. The CAISO does not provide any compelling reason to limit the applicability of the mPDR model to the MGO PEM. Additionally, the Straw Proposal correctly notes that the MGO PEM is rarely used, thereby limiting the change's potential impact.^[2] Restricting the change to just the MGO would discourage participation and limit the potential benefits of market participation. The CAISO should therefore modify the Straw Proposal to allow the mPDR model to be used by resources using all PEMs, rather than just the MGO PEM.

^[2] Straw Proposal and Issue Paper, at 11.

4. Are there considerations not mentioned in the paper for how individual end-use customers within a PDR should be treated (e.g., specifying which individual exporting customers should be zeroed out, or applying a pro-rata approach across all customers)?

The DRP should be allowed to determine how individual end-use customers within an mPDR aggregation are credited with exports. Since the DRP will be responsible for creating aggregations of exporting and non-exporting customer resources, it should be allowed to determine how to allocate credits to encourage participation and maximize benefits for all participating customers. If the goal of the mPDR model is to increase market participation by behind-the-meter (BTM) DERs that can reduce peak capacity, DRPs are better positioned to design compensation mechanisms for participating resources to achieve this objective.

CCAs currently manage a variety of DR and DER programs, including several that offer virtual power plant (VPP) programs.^[3] These programs often encompass a variety of DER and flexible demand resources, including solar, energy storage, electric vehicle charging, smart thermostats, heat pumps, and other controllable smart appliances. These programs are designed to accomplish a variety of objectives, including reducing demand during peak times, providing customer bill savings, providing reliability, encouraging electrification, and reducing greenhouse gas emissions. CCAs must be able to design programs, including the allocation of exported energy from DERs participating in an mPDR aggregation, designed to benefit the customers and communities they serve. The CAISO should therefore allow CCAs and other DRPs to determine how individual customers are compensated for participation in an mPDR aggregation.

^[3] See, e.g., Peninsula Clean Energy, Silicon Valley Clean Energy Jointly Launch Demand Flexibility Initiatives (Nov. 3, 2025): <https://svcleanenergy.org/news/peninsula-clean-energy-silicon-valley-cleanenergy-jointly-launch-demand-flexibility-initiatives/>; MCE Unveils Plans for Virtual Power Plant to Benefit Disadvantaged Richmond Residents and Business (June 21, 2022): <https://mcecleanenergy.org/mce-unveilsplans-for-virtual-power-plant-to-benefit-disadvantaged-richmond-residents-and-businesses/>; Ava Community Energy Announces Ambitious Virtual Power Plant Initiative to Help its 2M Customers Optimize Their Energy Investments While Relieving Stress on the Grid (Apr. 24, 2025): <https://avaenergy.org/news/ava-announcesvirtual-power-plant-initiative/>.

5. Provide your organization's feedback regarding the proposal for exporting customers to have an approved interconnection for export onto the distribution system.

The CAISO should clarify the Straw Proposal to confirm that DRPs can create aggregations consisting of exporting and non-exporting DR and DERs within a sub-LAP to maximize exported energy. While only customers with a Rule 21 export agreement will be eligible to export under the mPDR mechanism, aggregators are responsible for creating a portfolio of DER/DR resources within

a sub-LAP to optimize export credits under the mPDR construct. The CAISO's Straw Proposal should therefore ensure that DRPs are able to create aggregations consisting of exporting and non-exporting, as long as only Rule 21 customers are eligible to export.

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

CalCCA recommends that the CAISO clarify the Track 2 Issue Paper in three ways to provide additional information regarding the Issue Paper's applicability and details. *First*, the Issue Paper should be expanded to consider flexible resource participation options for large loads located in *both* CAISO BAAs and non-CAISO BAAs. While the Issue Paper appears to discuss large loads in the context of the non-CAISO [Western Energy Imbalance Market \(WEIM\)](#) and extended day-ahead market (EDAM) footprint, the CAISO-BAA is also forecast to receive a significant number of large-load interconnections in the coming years.^[4] CalCCA agrees with the CAISO's approach to "not presume[e] that all large loads are flexible or [that they] should automatically be treated as supply-side resources" and instead "create a set of participation options that accommodate a range of capabilities and business models."^[5] The CAISO should discuss further with stakeholders how large loads customers plan to participate in demand flexibility to inform participation options.

Second, the CAISO should also consider how to model large loads with DR capability within the CAISO BAA to ensure their load-reduction capability is accurately represented. Most loads participating in the CAISO DR market models are modeled at the sub-LAP level. Using 24 sub-LAPs to establish the boundaries for DR resource aggregations has worked well for the CAISO thus far, as loads participating in DR aggregations have historically been smaller and more dispersed across the sub-LAP. However, as large loads like data centers increasingly interconnect, the CAISO should consider how DR for large loads may need to be modeled differently to ensure the CAISO's market model accurately reflects how large loads' DR capabilities will impact pricing, dispatch, congestion, and system reliability. For example, data centers with DR may be more accurately reflected via a custom-LAP where the data center load is not lumped into a sub-LAP with other smaller, more dispersed loads.

Third, the CAISO should clarify the stakeholder process[es] that will be used to discuss large load flexibility issues. CalCCA understands that these issues may be considered in the CAISO's upcoming Large Loads initiative. Thus far, the Large Loads initiative has focused on technical requirements and standards, but will soon evolve to also consider other policy-related questions, such as co-located loads and generation, transmission service offerings, and cost-allocation.^[6] The CAISO should clarify how the DDEMI and Large Loads initiatives will interact and where issues related to large-load flexibility will be addressed.

^[4] Large Loads Technical Requirements (Mar. 10, 2026), at 6: <https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Large-Loads-Technical-Requirements-Mar-10-2026.pdf>.

^[5] Issue Paper, at 22.

^[6] Large Loads Technical Requirements, at 7.

7. What locational construct, such as sub-LAP, CLAP, or BAA-level aggregation, facilitate reliable demand response market participation in WEIM/EDAM BAAs?

CalCCA has no comments at this time.

8. Is DRRS suitable for demand response resources outside the CAISO BAA, or should other BAA-managed registration systems be explored? Why or why not?

CalCCA has no comments at this time.

9. Does your organization support the ISO pursuing modifications to the existing RDRR construct to capture WEIM/EDAM BAA considerations? What modifications would you recommend and why? Alternatively, should the ISO consider developing a new reliability-triggered demand response product applicable to all BAAs?

CalCCA has no comments at this time.

10. Do the proposed large load participation pathways adequately reflect the capabilities and preferences of large load? If not, what changes would you recommend and why? Is there other industry guidance or participation frameworks the ISO should be aware of?

CalCCA has no comments at this time.

11. Should the exception criteria for the 100 MW RDRR discrete dispatch limit be modified to better accommodate large aggregated demand response portfolios? Why or why not?

CalCCA has no comments at this time.

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

CalCCA recommends that the CAISO include CCA representatives in the “Related Issues – Coordination Framework” effort. While CCAs do not own or operate grid infrastructure, they comprise roughly one-third of the CAISO load and manage DERs and flexible loads via programs and, increasingly, VPP software platforms. CCAs can therefore play an important role in supporting accurate short-term forecasting, strengthening situational awareness, and optimizing and supporting reliable grid operations via flexible loads and resources, and should be included in these efforts.

The CAISO should also clarify the term ‘flexible load,’ specifically what it includes in the context of the Near-Term Proposal for Q3 of 2026. The Straw Proposal and Issue Paper includes discussions about a variety of flexible loads, including BTM DERs and DR, large loads interconnected at both the distribution and transmission level, and Participating Loads such as pumped storage. CalCCA is unsure what the CAISO intends to include in the scope of the Near-Term Proposal and recommends that the CAISO define which types of flexible loads are under consideration for this effort.

Finally, the CAISO should modify the Straw Proposal and Issue Paper to include the exploration of device-level measurement in the mPDR Straw Proposal and in future PEM discussions. Device-level measurement was discussed at length during the 2025 DDEMI WG meetings, but is not specifically included in any near-, medium-, or long-term proposals. The November 26, 2025, DDEMI WG Discussion Paper identified the lack of device-level measurement in developing PEM baselines, including the requirement for revenue-grade metering, as a barrier to participation for many resource types.[\[7\]](#)

Device-level measurement could enable participation of a variety of resources that lack revenue-grade metering, such as smart thermostats and appliances, in mPDR aggregations. This could further enhance a DRP's ability to maximize exports by allowing it to combine exporting DERs with non-exporting, load-reducing flexible resources. The CAISO should therefore modify the Straw Proposal and Issue Paper to incorporate the exploration of device-level metering as a component of the mPDR proposal and any future discussion of PEMs.

[7] See DDEMI WG Discussion Paper (Nov. 26, 2025): <https://stakeholdercenter.caiso.com/InitiativeDocuments/Discussion-Paper-Demand-and-Distributed-Energy-Market-Integration-Nov-26-2025.pdf>.



Comments on Mar 13 meeting discussion and Track 1 Straw Proposal and Track 2 Issue Paper

Initiative: Demand and distributed energy market integration

Comment period

Mar 13, 2026, 08:30 am - Mar 27, 2026, 05:00 pm

Submitting organizations

MCE

MCE

Submitted on 03/27/2026, 01:59 pm

Contact

Jordyn Bishop (jbishop@mceCleanEnergy.org)

1. Please provide your organization's feedback on the DDEMI meeting discussion on March 13, 2026 and "Demand and Distributed Energy Market Integration Track 1: Straw Proposal: Reflecting End-User Exports in Demand Response and Track 2: Demand Flexibility Enhancements" paper.

MCE appreciates the opportunity to submit these comments on the meeting discussion on March 13, 2026 and the "Demand and Distributed Energy Market Integration Track 1: Straw Proposal: Reflecting End-User Exports in Demand Response and Track 2: Demand Flexibility Enhancements" paper. MCE is supportive of the CAISO's proposed direction of implementing near-term practical solutions, alongside the exploration of longer-term market design enhancements. We encourage the CAISO to maintain this approach as outlined in the paper.

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

MCE strongly supports Track 1 as the most immediate near-term solution. MCE commends and supports the CAISO's goal of bringing the Track 1 proposal to the Board in August 2026. The Track 1 proposal addresses a critical limitation of the current Proxy Demand Resources (PDR) model by shifting the current export prohibition to the aggregation level, rather than the current individual customer level. This will allow demand response providers (DRPs) and the CAISO to capture the additional export capacity that already exists, while maintaining the resource model as a load curtailment product. This is a practicable, near-term solution that will result in immediate benefits to the market and its participants with minimal implementation effort required for the CAISO.

3. Should the change in the straw proposal apply to all PEMs or be limited to MGO? Why or

why not?

The change in the Track 1 straw proposal should apply to all Performance Evaluation Methodologies (PEMs). The underlying problem of accounting for customer-level exports exists across all PEMs, therefore the change should apply to all PEMs. MCE agrees with the CAISO's concern as noted in the March 13, 2026 presentation – limiting the proposal to the metering generator output (MGO) methodology would significantly constrain the proposal's impact given that most existing PDR resources use other PEMs.

4. Are there considerations not mentioned in the paper for how individual end-use customers within a PDR should be treated (e.g., specifying which individual exporting customers should be zeroed out, or applying a pro-rata approach across all customers)?

MCE strongly agrees with the CAISO's proposal in which scheduling coordinators (SCs) submit aggregated meter data for settlement, and the CAISO need not specify which end-use customer would be zeroed out. MCE further recommends that the CAISO provide maximum flexibility to the DRPs/SCs regarding the treatment of individual end-use customers within an aggregation, given that DRPs/SCs are best positioned to manage and optimize their unique portfolio-level resources.

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

5. Provide your organization's feedback regarding the proposal for exporting customers to have an approved interconnection for export onto the distribution system.

MCE supports the Track 1 proposal requirement that exporting customers must have an approved interconnection agreement with the governing utility distribution company that enables them to export energy (i.e., Rule 21 export agreement). This appropriately acknowledges the existing interconnection approval processes at the distribution-level, without imposing duplicative requirements at the CAISO level.

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

MCE has no comments on the Track 2 Issue Paper at this time, but intends to remain an active participant in future stakeholder sessions and may offer comments on subsequent iterations of the proposal.

7. What locational construct, such as sub-LAP, CLAP, or BAA-level aggregation, facilitate reliable demand response market participation in WEIM/EDAM BAAs?

See Question 6 response.

8. Is DRRS suitable for demand response resources outside the CAISO BAA, or should other

BAA-managed registration systems be explored? Why or why not?

See Question 6 response.

9. Does your organization support the ISO pursuing modifications to the existing RDRR construct to capture WEIM/EDAM BAA considerations? What modifications would you recommend and why? Alternatively, should the ISO consider developing a new reliability-triggered demand response product applicable to all BAAs?

See Question 6 response.

10. Do the proposed large load participation pathways adequately reflect the capabilities and preferences of large load? If not, what changes would you recommend and why? Is there other industry guidance or participation frameworks the ISO should be aware of?

See Question 6 response.

11. Should the exception criteria for the 100 MW RDRR discrete dispatch limit be modified to better accommodate large aggregated demand response portfolios? Why or why not?

See Question 6 response.

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

MCE has no additional comments on the Track 1 Straw Proposal, and no comments on the Track 2 Issue Paper at this time. MCE intends to remain an active participant in future DDEMI stakeholder sessions, and plans to offer comments on subsequent iterations of the proposals.

**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 OPENING COMMENTS
ON ADMINISTRATIVE LAW JUDGE'S RULING AUTHORIZING PARTIES TO
FILE COMMENTS ON ISSUES TO ADDRESS IN TRACK 3**

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On behalf of !
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION !

March 27, 2026

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ATTACHMENT A – CALCCA DATA MATRIX

SUMMARY OF RECOMMENDATIONS¹

CalCCA recommends that the Commission:

- Adopt a broad scope for Track 3, including all scoping items originally identified in the OIR, as well as additional items to allow a thorough review that addresses PCIA and ERRA structural, methodological, and implementation issues;
- Establish a Phase 1 of Track 3, to first resolve data access and confidentiality issues prior to commencing a Phase 2 focused on substantive party proposals;
- Adopt a data access protocol consistent with the protocol established in R.17-06-026, requiring the scope and term of data set forth in CalCCA's Data Matrix, attached hereto as Attachment A; and
- Provide a minimum of six months following data production for analysis and proposal development by all parties in Track 3, Phase 2.

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

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

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

R.25-02-005

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION’S OPENING COMMENTS
ON ADMINISTRATIVE LAW JUDGE’S RULING AUTHORIZING PARTIES TO
FILE COMMENTS ON ISSUES TO ADDRESS IN TRACK 3**

California Community Choice Association² (CalCCA) submits these opening comments pursuant to the February 20, 2026, Ruling (R.25-02-005) (‘R.25-02-005’). The Ruling seeks comments on: (1) issues to be addressed in Track 3; (2) data access/confidentiality impacting stakeholders’ ability to address these issues; and (3) duration of Track 3, highlighting process/timing interdependencies.

I. INTRODUCTION

This proceeding was opened to review the Power Charge Indifference Adjustment (PCIA) and Energy Resource Recovery Account (ERRA) rules and processes to ensure the “fair and equitable division of costs between bundled and departed load customers.”⁴ While Tracks 1

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 R.25-02-005 (Feb. 2, 2026).

⁴ A.25-02-005 (Feb. 26, 2025) (OIR), at 3.

and 2 examine discrete PCIA issues,⁵ the Ruling states that “Track 3 of this proceeding intends to address the broader set of remaining issues”⁶ related to the PCIA and ERRA frameworks.

The Ruling first seeks feedback on the Track 3 scope. The PCIA has been in place for nearly 25 years, facing critiques at various times by investor-owned utilities (IOUs), community choice aggregators (CCAs), and electric service providers (ESPs) and changing in both composition and design over that period. Periodically, as the Commission did in R.17-06-026,⁷ the PCIA warrants a fulsome review. As noted by President (then Commissioner) Reynolds at the first Prehearing Conference in this case, the Commission “want[s] parties to help [the Commission] rethink the PCIA and come up with the most fair, robust and efficient long-term approach to ensuring indifference.”⁸ President Reynolds added that the Commission “is open to reconsidering some proposals that were set aside when the PCIA was originally developed.”⁹ The Commission should thus ensure the scope of Track 3 facilitates full exploration of PCIA modifications and alternative designs. Rulemaking 17-06-026 offers a useful example. That rulemaking enabled parties to explore a broad range of alternatives, including changes to the scope of cost categories included in the calculation, modified and additional benchmarks, energy and attribute allocations, sunseting, securitization, pre-payment, and other adjustments. The Track 3 scope should be similarly broad, avoiding the piecemeal approach that has been pursued thus far in this rulemaking.

Overall, CalCCA supports the OIR’s proposed scoping items, including:

- Consideration of the need for ERRA-specific **implementation guidance for RA program changes**, including those related to the implementation of the RA Slice of Day framework, as was raised in the 2025 ERRA forecast;
- Consideration of whether changes to the **BPP** directions, processes, and rules are necessary and justified, or whether complementary or replacement guidance for procurement activity review in ERRA compliance cases is necessary. Issues regarding sufficiency of BPPs have been repeatedly raised in individual ERRA proceedings, focusing on questions about whether **IOU management of procurement activities** is reasonable and in compliance with Commission rules;

⁵ Track 1 addressed the Resource Adequacy (RA) market price benchmark, concluding with Decision (D.) 25-06-049. Track 2 is currently considering Pre-2019 banked Renewable Energy Credit (REC) valuation.

⁶ Ruling, at 1.

⁷ A (“(,;%&'S'O'\$%1,304+#)>\$%1,'6,3+*\$\$. @,3+*\$&+@, !% ", : 6%&\$"+(, !4'+(%)'\$*+&<6,<5+,86 . +(, : 5)(1+,% " \$DD+(+%=+, ! "GO&'#+% ', R.17-06-026 (July 10, 2017).

⁸ R.25-02-005, 8(+5+)(%)\$%1, : 6%D+(+%=+,<() %&=(SC'@ R.25-02-005 (Apr. 7, 2025), at 5, lines 19-24.

⁹ ;HS".

- Consideration of improved **PCIA and ERRA mechanisms** to reduce rate volatility, possibly including adjustments to trigger mechanisms and processes. The Commission also intends to consider whether rules to improve utility forecasting should be created, including possible incentive mechanisms;
- Consideration of additional guidance for **vintaging** PCIA resources, especially with respect to changes to or investments in utility owned resources.

To ensure a comprehensive analysis of PCIA-related issues, CalCCA also recommends the Commission add the following scoping items to Track 3:

- Revisiting the PCIA **GHG-free methodology** to ensure it is valued in the PCIA portfolio; and
- Consideration of **structural changes to the PCIA**, revisiting alternatives explored in previous PCIA proceedings as well as new proposals, including but not limited to:
 - Changes to the **cost categories** included in the calculation;
 - Modified or additional **benchmarks**;
 - Energy and attribute **allocations**;
 - **Sunsetting** the PCIA to allow IOUs unencumbered access to the PCIA portfolios in an environment of growing load and to protect all customers from the volatility created by annual debits and credits of PCIA revenues;
 - **Securitization**;
 - **Pre-payment**;
 - Increasing tools available to LSEs serving departing load to **better predict future changes** in the PCIA; and
 - Other proposals intended to **ensure indifference and reduce, restructure, or remove the continuing obligations of unbundled customers to pay the PCIA**.

The Ruling also seeks feedback on whether and when access by all stakeholders to data underlying the PCIA are necessary. In anticipation of this question even before this Ruling was issued, beginning in December 2025 CalCCA met with Energy Division and corresponded with the IOUs regarding the need for such data. Based on the experience in R.17-06-026, and the approximately six months it took to resolve the data issues before any substantive work could begin on the PCIA framework, CalCCA sought to clarify the data needs early in the hopes of facilitating the data exchange. Indeed, the Commission recognized the “inherent asymmetry” in data access in R.17-06-026 between the IOUs, who hold most of the data and are able to analyze PCIA proposals at any time, and the CCAs whose customers also pay the PCIA but for whom access to the data is very limited:

[T]he IOUs possess the greatest amount of data, [and] preventing sharing . . . Although some of the requested data may not ultimately lead to useful recommendation, the goal at this stage of the proceeding . . . is to ensure that parties have access to data necessary to develop and test proposals for ensuring indifference.¹⁰

The same situation applies in the instant case. In addition, the Commission's Energy Division collects important data to formulate the market price benchmarks (MPBs), which are needed for analysis in this case in a manner that balances confidentiality and comprehensive record development.

CalCCA attempted to schedule a Meet and Confer with the IOUs and other parties to discuss data needs beginning in January 2026. The IOUs, however, sought to delay any discussion regarding data access until after Track 2 testimony was complete and the Track 3 scope schedule was more clearly defined. In addition, CalCCA has repeatedly sought from Energy Division the underlying data regarding the Track 1 RA MPB Staff Report, but those data were never provided.¹¹ Without both the IOU and Energy Division data, the CCAs are unable to meaningfully and equitably participate in Track 3.

Given this asymmetry in data access, CalCCA requests that the Commission resolve the data access and confidentiality issues first in a Phase 1 of Track 3, prior to considering substantive Track 3 proposals in a Phase 2. In Phase 1, the Commission should adopt a data access protocol similar to that adopted in R.17-06-026, incorporating an agreed set of data kept in a data room only accessible to approved reviewing representatives. A specialized Non-Disclosure Agreement (NDA), already agreed to in the 2017 case, can be used to ensure compliance with the data access protocol. In addition, this data access protocol should require the scope and term of data recommended by CalCCA in the CalCCA Data Matrix, attached hereto as Attachment A. Parties should be given six months from the receipt of data in Phase 1 to develop and analyze proposals in Phase 2.

¹⁰ !&&\$1%+", : 6# #S&&\$6%+(,)%" , !&&\$1%+", ! " #\$\$%'(')\$*+, -) . ,/0"1+,304\$%1, : 6%D\$(# \$%1,I=6C\$%1, J + #6,;&&0+&,)%" , J 6"\$Df\$%1,I=5+"04+@ R.17-06-026,(Nov. 22, 2017), at 17.

¹¹ CalCCA asked for the data at least eight times through email and in meetings with Energy Division staff, with Energy Division responding several times that the data is confidential and/or will not be provided.

In summary, CalCCA recommends that the Commission:

- Adopt a broad scope for Track 3, including all scoping items originally identified in the OIR, as well as additional items to allow a thorough review that addresses PCIA and ERRA structural, methodological, and implementation issues;
- Establish a Phase 1 of Track 3, to first resolve data access and confidentiality issues prior to commencing a Phase 2 focused on substantive party proposals;
- Adopt a data access protocol consistent with the protocol established in R.17-06-026, requiring the scope and term of data set forth in CalCCA’s Data Matrix; and
- Provide a minimum of six months following data production for analysis and proposal development by all parties in Track 3, Phase 2.

II. TRACK 3 SHOULD BE BROADLY SCOPED TO ACCOMPLISH THE OIR’S OBJECTIVE OF UPDATING AND REFORMING THE PCIA AND ERRA FRAMEWORKS

The Commission should adopt a broad Track 3 scope to fulfill the OIR’s objectives of considering updates and reforms to the PCIA and ERRA frameworks. The OIR states that utility ERRA proceedings are “intended to function as an individual electric IOU’s annual forecast and accounting review, not as a forum for evaluating and setting policy.”¹² However, the OIR states that “a range of policy issues” have recently arisen in ERRA cases, with “[a] substantial subset of these questions relat[ing] to our mechanism for ensuring customer indifference to retail load departure, the [PCIA].”¹³ The OIR notes the complexity of the PCIA, as well as “(1) changes in regulatory frameworks that underpin the main elements of the PCIA, in concert with changes to overall market and resource conditions; and (2) the consistent occurrence of issues in individual ratemaking cases that are better addressed in a rulemaking.”¹⁴ After considering the discrete RA MPB and Pre-2019 Banked REC issues in Tracks 1 and 2, Track 3 is intended to address the broader OIR issues. CalCCA continues to support the OIR scoping items, as well as additional scoping items to address overall structural changes to the PCIA to ensure indifference, while seeking to reduce, restructure, or remove the continuing obligation of unbundled customers to pay the PCIA.

A. Principles of CCA Autonomy and Independence Should be Considered in Conjunction with the OIR Objectives

The OIR states that the objectives of this proceeding are the following:

¹² OIR, at 10.

¹³ ;”k, at 11.

¹⁴ ;”k, at 13-14.

- 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.¹⁵

While these overarching themes, including mitigating and responding to rate volatility and ensuring indifference for all customers are high priorities for the CCAs, the Commission and parties should take these concepts one step further and consider how to fairly decouple the cost obligations of unbundled customers from their prior generation provider (the IOUs). CCAs do not intend to leave the IOUs holding the bag for overpriced resources purchased on departing load’s behalf, as the IOUs have previously stated.¹⁶ As noted in the OIR, however, the continuing PCIA obligation frequently results in drawn out litigation to determine whether bundled or unbundled customers are overpaying for resources and thus statutory indifference is not achieved. As noted at the February 20, 2025, meeting adopting the OIR, President (then Commissioner) Reynolds said that while specific “in the weeds rule changes and ERRA and PCIA” are necessary, this proceeding should be a “forward-looking big picture policy making venue” especially in light of load growth and a PCIA “built on the concept of load departures leading to unneeded procurement that remains with the utility.” An important consideration in Track 3, then, is how CCA autonomy and independence can be advanced to reduce, restructure, or remove the continuing obligation of unbundled customers to pay the PCIA, while ensuring fairness and indifference to the IOUs and bundled customers. The Track 3 scope should be designed with these objectives in mind, as set forth below.

¹⁵ ;"k, at 3, 16.

¹⁶ I++@,+K1K@,/6\$%' ,3+C4F, : 6# #+%'&,6D,I60'5+(%, :)4SD6(%\$),E"\$&6%, : 6#C)%F@,8)=SD\$=,L)&,)% ", E4+=('\$=, : 6#C)%F@,)% ",I)% ,M\$+16,L)&,N,E4+=('\$=, : 6#C)%F,6%, '5+,A("+(,;%&'\$'0'\$%1,304+#)>\$%1,'6, BC")'+,)% ", 3+D6(#,E%+(1F,3+&60(=+,3+=6*+(F, !=60% ',)% ", 86 . +(, : 5)(1+,;%"\$DD+(+=+, ! "GO&' #+%' , 864\$=\$+&,)% ", 8(6=+&&+&@,R.25-02-005 (Apr. 2, 2025), at 6 (“The fact that CalCCA is proposing to sunset the PCIA . . . is further evidence that their underlying intention here appears to be achieving a result where certain customers avoid paying for ongoing costs of resources procured on their behalf.”).

B. Proposed Track 3 Scoping Issues

CalCCA supports the OIR's identified scoping items, which should be considered in Track 3:

- Review of **Track One revisions to MPBs**, which should include review of the impacts of the Track One decision on PCIA rates implemented in 2026;
- Consideration of the need for ERRA-specific **implementation guidance for RA program changes**, including those related to the implementation of the RA Slice of Day framework, as was raised in the 2025 ERRA forecast;
- Consideration of whether changes to the **BPP** directions, processes, and rules are necessary and justified, or whether complementary or replacement guidance for procurement activity review in ERRA compliance cases is necessary. Issues regarding sufficiency of BPPs have been repeatedly raised in individual ERRA proceedings, focusing on questions about whether **IOU management of procurement activities** is reasonable and in compliance with Commission rules;
- Consideration of improved **PCIA and ERRA mechanisms** to reduce rate volatility, possibly including adjustments to trigger mechanisms and processes. The Commission also intends to consider whether rules to improve utility forecasting should be created, including possible incentive mechanisms;
- Consideration of additional guidance for **vintaging** PCIA resources, especially with respect to changes to or investments in utility owned resources.¹⁷

CalCCA further recommends that the following be incorporated into the Track 3 scope:

- Revisiting the PCIA **GHG-free methodology** to ensure it is valued in the PCIA portfolio; and
- Consideration of **structural changes to the PCIA**, revisiting alternatives explored in previous PCIA proceedings as well as new proposals, including but not limited to:
 - Changes to the **cost categories** included in the calculation;
 - Modified or additional **benchmarks**;
 - Energy and attribute **allocations**;
 - **Sunsetting** the PCIA to allow IOUs unencumbered access to the PCIA portfolios in an environment of growing load and to protect all customers from the volatility created by annual debits and credits of PCIA revenues;
 - **Securitization**;

¹⁷ OIR, at 23-24. CalCCA notes that cases involving vintaging issues are currently pending before the Commission. I++@,+K1K@,!CC4\$=)'\$6%,6D,8)=SD\$=,L)&,)%" ,E4+=('\$=, : 6#C)%F,'6,3+=6*+(,O+4#&,BC()'+, : 6&'&@ A.23-12-014 (Dec. 20, 2023); &+,)4&6,!CC4\$=)'\$6%,6D,I)% ,M\$+16,L)&,N,E4+=('\$=, : 6#C)%F,D6(,!CC(6*)4,6D,8)46#)(,M+=)(H6%\$7)'\$6%,M+#6&'(')'\$6%,8(6G+= '@ A.25-12-009 (Dec. 16, 2025). The Commission should resolve those cases now under existing vintaging rules despite potential consideration of vintaging guidance in the future in this case.

- **Pre-payment;**
- Increasing tools available to LSEs serving departing load to **better predict future changes** in the PCIA; and
- Other proposals intended to **ensure indifference** and **reduce, restructure, or remove the continuing obligations of unbundled customers to pay the PCIA.**

Each of these issues requires an evaluation of PCIA portfolio composition, forecasting assumptions, and valuation methodologies. As a result, meaningful participation on these topics depends on access to comprehensive and granular data, as discussed below.

III. LSES WHOSE CUSTOMERS PAY THE PCIA REQUIRE ACCESS TO PCIA-RELATED IOU AND CPUC DATA TO ENABLE EQUAL AND MEANINGFUL ENGAGEMENT IN TRACK 3

As noted above, CalCCA supports a broad scope for this proceeding, requiring a robust review and analysis to address fundamental issues surrounding the PCIA and ERRAs frameworks. However, data used in the calculation of PCIA inputs, processes, and mechanisms, including the establishment of the MPBs and the processes for determining the ongoing costs and values of the IOUs' PCIA-eligible resource portfolios, are held by the IOUs and the CPUC. For the purposes of the annual ERRA cases, CCAs have generally only received data from the forecast-year. Other data, particularly those data necessary to develop multi-year forecasts of PCIA costs and values and to evaluate the impacts of proposed modifications, have not been made available to CCAs.¹⁸ The IOUs have stated in annual ERRA Forecast cases and in R.17-06-026 that requested granular information exceeding routinely provided information is either

¹⁸ While the Commission provided an option to address this lack of data access for PCIA forecasting purposes in D.22-07-008, the requirements placed on CCA receipt and use of these data were highly restrictive and effectively unworkable. I++,D.22-07-008, M+=&\$6%,3+&64*\$%1,85)&+,P,;&&0+&,3+4)'+' , '6,M)') , !==+&&,)% " ,Q640%') (F, !446=) '\$6%&,\$%, J)(>+',8(\$=+,R+=5#)(>, :)4=04)'\$6%& R.17-06-026 (July 19, 2022) (placing multiple restrictions on CCA requests for data, including requiring CCA reviewing representations to provide any disclosures provided to their CCA clients and prepared based on the received information with the Commission and IOUs themselves, and limiting how often reviewing representatives could share the data with their CCA clients).

irrelevant to the proceeding¹⁹ and/or confidential or “market sensitive.”²⁰ In this PCIA proceeding, CCAs have also not been successful in obtaining data underlying the Commission’s own analysis forming the basis for the Staff Report in Track 1.²¹

The Commission is required to base its decisions on fact and evidence, necessitating a fully developed administrative record to substantiate all material findings.²² The Commission is further required to render its decisions based on the law and on the evidence in the record, relying on evidentiary support rather than speculation on unsupported assumptions.²³ To satisfy this legal standard, parties must have meaningful access to data that is reasonably necessary to analyze, verify, and if appropriate, challenge proposals, assumptions and methodologies offered for Commission consideration.

CalCCA anticipates that the IOUs (and potentially other stakeholders) will raise confidentiality concerns in this case with respect to needed data underlying PCIA forecasts and valuation methodologies. CalCCA also expects the IOUs to raise concerns similar to those raised in R.17-06-026 regarding the relevance of data CalCCA believes is necessary for evaluating substantive proposals. For example, CalCCA anticipates needing data covering both a limited

¹⁹ For example, in response to a CalCCA discovery request in the SCE ERRRA Forecast case, R.25-05-008, in which CalCCA requested that SCE “Please explain if SCE’s proposed formula for calculating the effective contribution of RA capacity from storage resources is used when SCE submits RA compliance showings to the CPUC for the 2024 slice of day test period,” SCE responded with the following:

SCE objects to this question on the basis that the historical 2024 slice-of-day test period is outside the scope of this proceeding and is neither relevant to the subject matter of this proceeding nor reasonably calculated to lead to the discovery of admissible evidence.

I60'5+(%, :)4SD6(%\$),E"\$&6%,S,PTPU,E33 !,96(+=)&'M')',3+VO+&'I+', :)4 : : !WI : E,TTP,(Response Date: June 17, 2025).

²⁰ I++@,+K1K@,/6\$%,3+&C6%&+,6D,8)=\$D\$=,L)&, % ",E4+=('\$=, : 6#C)%F,XB,?YEZ@,I60'5+(%, :)4SD6(%\$), E"\$&6%, : 6#C)%F,XB,??[EZ@,)% ",I)%M\$+16,L)&,N,E4+=('\$=, : 6#C)%F,XB,YTPEZ,'6,! "#\$%\$&'('\$*+, -) . , /0"1+2&,304\$%1,3+VO+&'\$%1, : 6# #+% '&,6%,8 ; ; !,96(+=)&'\$%1,M')', !==+&&@,R.17-06-026 (Dec. 9, 2021), at 3 (arguing against permitting a “reviewing representative to use confidential, market sensitive IOU procurement data or other market sensitive materials for rate forecasting”).

²¹ I++,&OC()@,n. 11; &++,)4&6, :)4SD6(%\$), : 6# #0\$F, : 56\$=+, !&&6=\$)'\$6%, !CC4\$=\$)'\$6%,D6,(,3+5+)\$%1,6D, M+=&&6%,P\WTUWTJY@ R.25-02-005,(July 28 2025), at 34 (“Several Parties, including CalCCA, requested data from Energy Division supporting its conclusions in the Staff Report throughout this process (citation omitted). Despite numerous requests, no data has been received demonstrating how the factors identified in the Decision lead to a lack of indifference. Parties could not verify the Energy Division’s conclusions independently. Parties were also unable to model future impacts of the Decision’s changes based on the actual data reviewed by Energy Division.”).

²² I++ ,Public Utilities Code § 1757.

²³ ;H\$"K,

historical period and a significant time period into the future for use in evaluating forecasting techniques and methodologies and to establish and verify resource valuations. These data are directly relevant and critical to the issues that will likely be considered in Track 3. Given these data needs, CalCCA sets forth below its proposal for a data access protocol to allow fair access to the required data.

IV. A DATA ACCESS PROTOCOL MODELED AFTER THE PROTOCOL ADOPTED IN THE 2017 CASE SHOULD BE ADOPTED IN A PHASE 1 OF TRACK 3 PRIOR TO SUBSTANTIVE TRACK 3 PROPOSALS BEING CONSIDERED IN PHASE 2

CalCCA requests the Commission follow the approach taken in R.17-06-026 and address data access issues in an initial Phase 1 prior to addressing substantive Track 3 proposals in a Phase 2 at least six months after data is received by all parties. Parties should only be expected to evaluate and/or propose alternatives after they have received sufficient data with which to analyze these alternatives and their impacts. The Commission should adopt a data access protocol similar to the protocol used R.17-06-026 and incorporate the data set forth in CalCCA’s proposed Data Matrix, attached hereto as Attachment A. Doing so will avoid foreseeable delays in the proceeding’s schedule and ensure that all stakeholders have access to the same information as proposals are developed and analyzed in Phase 2 of Track 3.

A. Broad Access to IOU Data Was Required Through a Data Access Protocol in R.17-06-026 After Significant Delays

From the beginning of R.17-06-026, CalCCA expressed concern that parties would need significantly greater access to IOU data than previously provided to participate meaningfully and effectively.²⁴ As CalCCA noted at the time, “[f]or CCAs to effectively participate in this proceeding and address key non-bypassable charge issues, CCA legal and regulatory staff must have access to IOU procurement and portfolio management information that they are currently barred from reviewing.”²⁵ The Assigned Commissioner’s Scoping Memo similarly identified access to necessary data as a threshold issue and emphasized the importance of enabling parties to review the existing methodology and contribute to potential alternatives.²⁶ Despite this directive, progress on the substantive issues in the proceeding was delayed for several months

²⁴ 8(+5+)(%)1, : 6%D+(+%=+,I')'+#+% ',6D,'5+, :)4\$D6(%\$), : 6# #0%'F, : 56\$=+, !&&6=)\$ '\$6%, R.17-06-026 (Aug. 24, 2017), at 4.

²⁵ ;H\$".

²⁶ I++,I=6C\$%1, J +#6,)%" ,304\$%1,6D, !&&\$1%+" , : 6# #\$\$&\$6%+(, R.17-06-026 (Sept. 25, 2017) (Sept. 2017 PCIA Scoping Memo), at 21.

while parties disputed the extent of non-IOU access to IOU portfolio and contract data.²⁷ As described below, the Commission ultimately ordered the IOUs to provide access to previously withheld data covering a broader period of time than the IOUs asserted was necessary.²⁸

From the OIR to the resolution of data access, six months passed without the ability of parties to delve into substantive analysis of proposals for the case. The Commission initially directed parties to engage in a “meet and confer” process to resolve data access issues²⁹ and required a “Joint Report” by October 16, 2017.³⁰ However, that process did not result in consensus.³¹ The IOUs disagreed with other stakeholders regarding the appropriate level of granularity and the time periods for requested data, asserting that certain requests were unduly burdensome and/or irrelevant.³²

Following review of the Joint Report, the Assigned Commissioner and Administrative Law Judge (ALJ) directed the parties in November 2017 to continue to meet and confer regarding data access.³³ They noted that the lack of consensus represented “a serious departure” from the Scoping Memo³⁴ and emphasized the importance of addressing data asymmetry among the IOUs and CCAs.³⁵ The Assigned Commissioner and ALJ also rejected the IOU proposals to limit the time period for data production, directing that pre-2014 data be provided.³⁶ They then ordered a continuation of the meet and confer process to resolve the remaining open issues.³⁷

²⁷ The Commission’s original schedule for the entire proceeding had to be revised due to these disputes. In fact, as the parties began developing substantive proposals, they raised concerns that delays in obtaining data had impaired their ability to meet the original schedule. I++ , ! # + % " + " , I = 6 C \$ % 1 , J + # 6 ,) % " , 3 0 4 \$ % 1 , 6 D , ! & & \$ 1 % + " , : 6 # # \$ & & \$ 6 % + (@ , R . 1 7 - 0 6 - 0 2 6 (Mar . 2 , 2 0 1 8) , at 4 . The Assigned Commissioner agreed, and noted somewhat ironically that the IOUs objected to an extension of the proceeding schedule, notwithstanding that the IOUs themselves caused the delay in data access. ; H \$ " . Finally, in March of 2018 the Assigned Commissioner revised the schedule, emphasizing the need to balance timely resolution with thorough review and due process. ; " k , at 5 , 7 .

²⁸ ! & & \$ 1 % + " , : 6 # # \$ & & \$ 6 % + (,) % " , ! & & \$ 1 % + " , ! " # \$ % \$ & ' () ' \$ * + , -) . . / 0 " 1 + , 3 0 4 \$ % 1 , L () % ' \$ % 1 , 3 + 4 \$ + D , I 6 0 1 5 ' , \$ % , M + = + # H + ([@ , P T ^ _ , I O C C + # + % ') 4 , / 6 \$ % ' , 3 + C 6 (' , 6 % , M ') , ; & & 0 + & , R . 1 7 - 0 6 - 0 2 6 (Dec . 2 0 , 2 0 1 7) , at 4 - 5 .

²⁹ ! # + % " + " , I = 6 C \$ % 1 , J + # 6 ,) % " , 3 0 4 \$ % 1 , 6 D , ! & & \$ 1 % + " , : 6 # # \$ & & \$ 6 % + (@ , R . 1 7 - 0 6 - 0 2 6 (Mar . 2 , 2 0 1 8) , at 2 2 .

³⁰ ; " . , at 2 3 .

³¹ I + + I) % , M \$ + 1 6 , L) & , N , E 4 + = ' (\$ = , : 6 # C) % F , X B , Y T P , E Z , I O H # \$ & & \$ 6 % , 6 D , / 6 \$ % ' , 3 + C 6 (' , 6 % , 3 + & 0 ' & , 6 D , J + + ' ,) % " , : 6 % D + (, 3 + 1) (" \$ % 1 , M ') , ; & & 0 + & @ R . 1 7 - 0 6 - 0 2 6 (Oct . 2 3 , 2 0 1 7) , Appendices F and H .

³² ; H \$ " .

³³ ! & & \$ 1 % + " , : 6 # # \$ & & \$ 6 % + (,) % " , ! & & \$ 1 % + " , ! " # \$ % \$ & ' () ' \$ * + , -) . . / 0 " 1 + , 3 0 4 \$ % 1 , : 6 % D \$ (# \$ % 1 , I = 6 C \$ % 1 , J + # 6 , ; & & 0 + & ,) % " , J 6 " \$ D F \$ % 1 , I = 5 + " 0 4 + @ R . 1 7 - 0 6 - 0 2 6 , (Nov . 2 2 , 2 0 1 7) , at 5 - 6 .

³⁴ ; " . , at 6 .

³⁵ ; " k , , at 1 7 .

³⁶ ; " . , at 1 2 .

³⁷ ; " . , at 2 .

Finally, a “Supplemental Joint Report” among the parties on December 8, 2017 set forth a consensus data access framework, including agreed-upon data categories, confidentiality protections, and a Modified NDA governing access.³⁸ The Commission approved this framework shortly thereafter.³⁹ The Commission ordered the parties to make available a defined set of data categories, including specified time periods, and approved the proceeding-specific NDA.⁴⁰

CalCCA has recently sought to avoid this back and forth in this case by meeting with parties and Energy Division but, to date, as described above, those efforts have not been successful. Thus, to address any asymmetry in data access, and to avoid unnecessary delays, CalCCA requests that the Commission resolve data access issues in a Phase 1 of this proceeding, prior to consideration of substantive Track 3 issues in a Phase 2. Early resolution will provide stakeholders with the time and information necessary to participate fully in the substantive phase.

B. A Track 3 Data Access Protocol Modeled on the 2017 Data Access Protocol and Incorporating CalCCA’s Data Matrix Should be Adopted

The Commission should adopt a data access protocol consistent with the approach approved in R.17-06-026, requiring the disclosure of the data set forth in CalCCA’s Data Matrix. First, the data access protocol should include the components adopted in the 2017 case including a Modified NDA, defined data categories, and a structured data-sharing process to ensure that parties can effectively review the current PCIA methodology and contribute to the development of potential alternatives. This data-sharing process includes:

- A secure data-sharing repository (“data room”);
- Access limited to Reviewing Representatives operating under a Commission-approved NDA; and
- Tiered confidentiality treatment (public, Modified NDA, Model NDA), consistent with the framework previously approved by the Commission.⁴¹

The Commission already determined that this framework appropriately balances confidentiality concerns with the need for transparency and analytical rigor.⁴²

³⁸ I),M\$+16,L) &,N,E4+=('\$=, : 6#C)%F,XB,YTP,EZ,I0H#\$\$\$6%,6D,IOCC4+#+%')4,/6\$%' ,3+C6(' ,6%, 3+&04'&,6D, J ++',)% " , : 6%D+(,3+1)("\$%1,M)') ,;&&0+&&R.17-06-026 (Dec. 8, 2017).

³⁹ !&&\$1%+" , : 6# #\$\$\$6%+(,)% " , !&&\$1%+" , ! " #\$\$\$&' () '\$*+, -) . /0" 1+,304\$%1,L()%'\$%1,3+4\$+D,I6015', \$%,M+=+ #H+(, [@,PT^ _ , IOCC4+#+%')4,/6\$%' ,3+C6(' ,6%,M)') ,;&&0+&, R.17-06-026 (Dec. 20, 2017), at 4-5.

⁴⁰ ;H\$".

⁴¹ ;"k, at 2, 4-5.

⁴² ;"k, at 4-5.

Second, the Commission should adopt CalCCA's Data Matrix which identifies specific data categories and relevant timeframes (generally 2019–2025 historical data and 2026–2045 projections). This Data Matrix is informed by, but appropriately expands upon, the data categories adopted in R.17-06-026 to reflect the broad scope of Track 3. Overall, the categories of data necessary to support the broad Track 3 scope include data:

- Identifying resources in the PCIA-eligible portfolios;
- Necessary to create PCIA forecasts;
- Necessary to evaluate PCIA alternatives;
- Used to establish the Market Price Benchmarks; and
- Necessary to establish valuations for each resource and attribute type.

The data specified in the CalCCA Data Matrix form the foundational inputs required to understand portfolio composition, forecast costs, assess market value, and evaluate the reasonableness of proposed changes.⁴³ The purpose is to enable independent analysis and development of proposals, rather than reliance on an IOU's or Energy Division's characterizations of the data. Providing a common evidentiary foundation supports fairness and competitive neutrality and allows rigorous testing of assumptions.

C. The Track 3 Schedule Should Be Phased to First Address Data Access Issues and to Allow Six Months from the Receipt of All Data for Track 3 Proposal Development and Analysis

Given the delays in R.17-06-026 discussed above, early adoption of CalCCA's proposed framework is necessary to avoid similar schedule disruptions in this proceeding. The Commission should therefore establish a phased procedural sequence that prioritizes resolution of data access issues in Phase 1 before initiating proposal development in Phase 2. Given data access is a prerequisite to meaningful analysis, CalCCA recommends that parties be afforded no less than six months from the date the requested data are made available to review and understand the data, conduct substantive analysis, and develop informed proposals. Indeed, the IOUs have continuous access to the underlying data, while non-IOU parties must first obtain, process, and analyze that information before they can engage in the substantive issues in this

⁴³ For example, the IOUs have stated in response to the OIR and in Track 2 Testimony that changes to the RPS MPB are necessary. To engage meaningfully on this issue, access to data underlying the calculation of the RPS MPB (and any proposed revision to the RPS MPB) would be necessary, none of which is currently available to non-IOU parties.

proceeding. Providing adequate time following data receipt is therefore necessary to mitigate this imbalance and ensure that all parties can participate on an equal footing.

Finally, the Commission should recognize that additional data needs may arise as parties develop and respond to proposals. To minimize the risk of further disputes and delays of the type experienced in R.17-06-026, the Commission should allow for targeted expansion of the Data Matrix where justified or ensure at the outset that the approved Data Matrix is sufficiently comprehensive to minimize the need for additional data production.

V. CALCCA'S RESPONSES TO QUESTIONS REGARDING TRACK 3 SCOPING ISSUES

- 1. What issues should be addressed in Track 3 of this proceeding? If you have views on how these issues should be prioritized, also provide that input.**

See Section II., above. CalCCA requests that the Commission prioritize consideration of overall structural changes to the PCIA framework to ensure indifference.

- 2. There may be data confidentiality and/or data access issues that affect how issues can or should be addressed by the parties. What data confidentiality issues are likely to arise in Track 3? How should the scope and schedule of Track 3 address these issues?**

See Sections III. and IV., above.

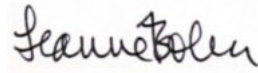
- 3. How long do you expect Track 3 will take to complete? What process/timing interdependencies may there be?**

CalCCA expects Track 3, Phase 1 regarding data confidentiality issues to take several months. After receipt of data, parties need at least six months for proposal development and analysis. Given the scope, and likely conflicting positions among parties and need for record development, CalCCA estimates that Track 3 will take at least one year, and possibly two years to complete. As set forth in Sections III. and IV., the primary interdependency in Track 3 is the need for data access prior to (and not parallel with) proposal development and analysis.

VI. CONCLUSION

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

Respectfully submitted,

A handwritten signature in black ink that reads "Leanne Bober". The signature is written in a cursive style with a light blue rectangular highlight behind it.

Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

March 27, 2026

**ATTACHMENT A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON
ADMINISTRATIVE LAW JUDGE'S RULING AUTHORIZING PARTIES TO FILE
COMMENTS ON ISSUES TO ADDRESS IN TRACK 3**

CALCCA DATA MATRIX

ATTACHMENT A - CALCCA DATA MATRIX

R.25-02-005 - NEWGEN PCIA Analysis - DATA NEEDS as of 3/27/26

Why	
1	Identifying PCIA Resource Portfolios
2	PCIA Forecasting
3	PCIA Alternatives
4	Market Price Benchmarks
5	Valuation

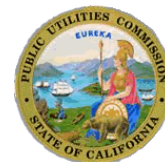
Category	Data Needed	Data Format	Historical Time Period	Forecast Time Period	Why
Power Purchase Agreements	Energy only purchase contracts	Monthly costs and volumes; see Contract Data Template	2019 - 2025	2026 - 2045	1, 2, 3, 4
	RA purchase contracts	Monthly costs and volumes, identify underlying resource technology; see Contract Data Template	2019 - 2025	2026 - 2045	1, 2, 3, 4
	REC purchase contracts	Monthly costs and volumes; see Contract Data Template	2019 - 2025	2026 - 2045	1, 2, 3, 4
	Bundled attribute purchase contracts	Monthly costs and volumes; see Contract Data Template	2019 - 2025	2026 - 2045	1, 2, 3, 4
Utility Owned Generation	Utility owned generation assets	Monthly costs and volumes; see UOG Data Template	2019 - 2025	2026 - 2045	1, 2, 3
	Net book value	Current net book value and annual depreciation expense by resource	2019 - 2025	2026 - 2045	1, 2, 3
	Capital additions	Annual plant in service additions by resource	2019 - 2025	2026 - 2045	1, 2, 3
	Relicensing capital additions	Annual plant in service additions by resource	2019 - 2025	2026 - 2045	1, 2, 3
	Cost of capital/revenue requirement conversion factor	Annual WACC and revenue requirement conversion factor for capital additions	2019 - 2025	2026 - 2045	1, 2, 3
Depreciation study	Most recent depreciation study, with detail by plant			1, 2, 3	
VAMO	Executed VAMO sales - Voluntary Allocation	Monthly revenue and volumes	2019 - 2025	2026 - 2045	1, 2, 3
	Executed VAMO sales - Market Offer	Monthly revenue and volumes	2019 - 2025	2026 - 2045	1, 2, 3
	VAMO allocations	Annual allocation of RPS resources, % and MWh, between bundled and departing load	2019 - 2025	2026 - 2045	1, 2, 3
Other Market Transactions	Executed RA sales	Monthly revenue and volumes, identify underlying resource technology	2019 - 2025	2026 - 2045	1, 2, 3
	Forecasted RA sales	Monthly revenue and volumes, identify underlying resource technology	2019 - 2025	2026 - 2045	1, 2, 3
	Executed non-VAMO RPS sales	Monthly revenue and volumes	2019 - 2025	2026 - 2045	1, 2, 3
	Forecasted non-VAMO RPS sales	Monthly revenue and volumes	2019 - 2025	2026 - 2045	1, 2, 3
	Other sales to third parties	Identify product(s) sold with monthly revenue and volumes	2019 - 2025	2026 - 2045	1, 2, 3
Miscellaneous PCIA costs	Collateral and fuel carrying costs	Annual expenses by PCIA vintage	2019 - 2025	2026 - 2045	2, 3
	Gas transportation costs	Annual expenses by PCIA vintage	2019 - 2025	2026 - 2045	2, 3
	Administrative costs (Energy Procurement Management)	Annual expenses by PCIA vintage	2019 - 2025	2026 - 2045	2, 3
	Other costs/revenue	Annual costs recovered through the PCIA; e.g. hydro sales, pension, etc.	2019 - 2025	2026 - 2045	2, 3
Load/Sales	Bundled load and demand forecast	Monthly energy and coincident peak demand by customer class	2019 - 2025	2026 - 2045	2, 3
	CCA load and demand forecast	Monthly energy and coincident peak demand by customer class	2019 - 2025	2026 - 2045	2, 3
	DA load and demand forecast (subject to PCIA)	Monthly energy and coincident peak demand by customer class	2019 - 2025	2026 - 2045	2, 3
	PCIA billing determinants	Annual sales by customer class by vintage used to determine PCIA rates	2019 - 2025	2026 - 2045	2, 3
Market Prices	NP15/SP15 market price forecast	Monthly forward on-peak and off-peak price curves		2026 - 2045	2, 3, 4
	System RA market price forecast	Monthly forward price curve as of [DATE], including premiums, discounts, or other distinguishing factors for different resource technologies		2026 - 2045	2, 3, 4
	Local RA market price forecast	Monthly forward price curve as of [DATE], including premiums, discounts, or other distinguishing factors for different resource technologies		2026 - 2045	2, 3, 4
	Flex RA market price forecast	Monthly forward price curve as of [DATE], including premiums, discounts, or other distinguishing factors for different resource technologies		2026 - 2045	2, 3, 4
	PCC1 REC market price forecast	Monthly forward price curve		2026 - 2045	2, 3, 4
	PCC2 REC market price forecast	Monthly forward price curve		2026 - 2045	2, 3, 4
	PCC3 REC market price forecast	Monthly forward price curve		2026 - 2045	2, 3, 4
	GHG-Free market price forecast	Monthly forward price curve		2026 - 2045	2, 3, 4
	Energy Index portfolio weight	Portfolio weighting applied to average energy price forecast		2026 - 2045	2, 3, 4
Procurement Plans	Bundled Procurement Plan				1, 2, 3, 4
	RPS Procurement Plan				1, 2, 3, 4
	RPS position	Annual RPS position detail (RPS compliance requirement, RPS generation, banked RECs used, remaining net long/short position)	2019 - 2025	2026 - 2045	1, 2, 3, 4
	Retained RPS	Monthly RPS MWh retained from PCIA resource portfolio for bundled customer compliance	2019 - 2025	2026 - 2045	1, 2, 3, 4
	Excess RPS sales	Monthly percent of excess RPS position sold to third parties	2019 - 2025	2026 - 2045	1, 2, 3, 4
	RA position	Monthly RA position detail (available RA, outages, constraints, reserves, sales, RA compliance requirement)	2019 - 2025	2026 - 2045	1, 2, 3, 4
	Retained RA (monthly)	Monthly RA MW retained from PCIA resource portfolio (by resource) for bundled customer compliance	2019 - 2024		1, 2, 3, 4
	Retained RA (hourly)	Monthly and hourly RA MW retained from PCIA resource portfolio (by resource) for bundled customer compliance	2025	2026 - 2045	1, 2, 3, 4
Excess RA sales	Monthly percent of excess RA position sold to third parties	2019 - 2025	2026 - 2045	1, 2, 3, 4	
Resource Valuation	Mark to market calculation	Net market value calculation (with workpapers) of each PCIA-eligible resource calculated as of [DATE]		2026 - 2045	3, 5
Other	Past ERRRA Forecast PCIA templates	Final indifference amount and PCIA rate workpapers from past ERRRA Forecast proceedings, including resource specific details	2019 - 2025	2026	2
	Revenue Fee and Uncollectible Factor		2019 - 2025	2026	2
	GRC generation revenue allocation factors		2019 - 2025	2026	2
Market Price Benchmarks	Historical RPS MPB calculation	Anonymized transaction data and calculation of RPS MPBs	2019 - 2025		3, 4
	Historical RA MPB calculation	Anonymized transaction data and calculation of RA MPBs	2019 - 2025		3, 4
	Historical GHG-Free MPB calculation	Anonymized transaction data and calculation of GHG-Free MPBs	2024 - 2025		3, 4
Monthly PABA and ERRRA Reports	PABA balancing account	Detailed monthly PABA accounting by line item	2019 - 2025		1, 3
	PABA underlying volumes	Volumetric information underlying monthly PABA accounting, format as provided in ERRRA proceeding master data requests	2019 - 2025		1, 3
	ERRRA balancing account	Detailed monthly ERRRA accounting by line item	2019 - 2025		1, 3

CONTRACT DATA TEMPLATE

Item	Notes
Confirm ID / Log Number	
CAISO Resource ID	
Contract/Resource Name	
Solicitation	
CPUC Authorization	
ERRA Resource Category	
Contract Type	QF, CHP, RPS, RA Sale, REC sale, etc
Product(s)	Energy, REC, RA, etc.
Purchase/Sale	
Resource Technology	For all transactions, including RA purchase and sales, note the underlying resource technology.
Location	
Counterparty	
PCIA Vintage	
Contract Execution Date	
Commercial Operation Date	
Contract Amendment Date(s)	
Contract Expiration Date	
RPS-Eligible	Y/N
VAMO-Eligible	Y/N
GHG-Free Eligible	Y/N
Contract Capacity	MW
RA Classification	System/Local
Local RA Area	
Flex RA Eligible	Y/N
Contract Price for RA	Monthly
Contract Price for REC	Monthly
Contract Price for Energy	Monthly
Energy	Monthly MWh
NQC	Monthly MW
EFC	Monthly MW
PCIA RA	Monthly MW RA used in PCIA calculation; PCIA RA may be different from NQC/EFC based on Commission approved modeling for Slice of Day
Contract Payment	Monthly \$000

UOG DATA TEMPLATE

Item	Notes
ID Number / Log Number	
CAISO Resource ID	
Resource Name	
Solicitation	
CPUC Authorization	
ERRA Resource Category	
Resource Technology	
Location	
PCIA Vintage	
Commercial Operation Date	
Depreciable Life (End Date)	
FERC Licence Term (Hydro)	
RPS-Eligible	Y/N
VAMO-Eligible	Y/N
GHG-Free Eligible	Y/N
Nameplate Capacity	MW
RA Classification	System/Local
Local RA Area	
Flex RA Eligible	Y/N
Energy	Monthly MWh
NQC	Monthly MW
EFC	Monthly MW
PCIA RA	Monthly MW RA used in PCIA calculation; PCIA RA may be different from NQC/EFC based on Commission approved modeling for Slice of Day
Fuel Costs	Monthly \$000
Fixed O&M	Monthly \$000
Variable O&M	Monthly \$000
GHG Costs	Monthly \$000
Grid Management Charge and Other Costs	Monthly \$000
Return on Rate Base	Monthly \$000
Total Revenue Requirement	Monthly \$000



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

FILED

03/30/26

02:32 PM

R2510003

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.

R.25-10-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY
COMMENTS ON TRANSACTABILITY ISSUES FILED AND SERVED**

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

CALIFORNIA COMMUNITY CHOICE
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March 30, 2026

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SUMMARY OF RECOMMENDATIONS¹

CalCCA proposes the Commission:

- Reject Vistra’s opposition to LOT, because Vistra: (1) incorrectly implies that the Commission did not intend to consider CalCCA’s LOT proposal; (2) applies the wrong transactability standard in its assessment of CalCCA’s proposal and the Report; (3) erroneously suggests that increasing compliance opportunities is bad for competition; and (4) improperly states that LOT can introduce market power concerns, despite LOT’s ability to help resolve market power concerns recently observed in the tight RA market.
- Adopt hourly LOT to remove structural barriers in the market to reduce reliance on fossil fuels and to promote affordability, as recommended by CEJA/Sierra Club;
- Dismiss claims regarding the uncertainty of LOT benefits, as demonstrated by CEJA/Sierra Club; and
- Recognize Forward Market Design’s demonstration of the ability to realize LOT’s benefits while minimizing the administrative costs of implementation, thereby rejecting Energy Division’s concerns regarding complexity of implementing LOT and assertions that LOT’s benefits cannot be substantively realized in a bilateral market.

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.25-10-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY
COMMENTS ON TRANSACTABILITY ISSUES FILED AND SERVED**

California Community Choice Association² (CalCCA) submits these comments pursuant to the *Assigned Commissioner's Scoping Memo and Ruling*³ (Scoping Ruling), dated December 12, 2025, and *Administrative Law Judge's Ruling on Energy Division's Transactability Report and Modifying Track 1 Schedule*,⁴ dated February 24, 2026.

I. INTRODUCTION

Hourly load obligation trading (LOT) has the potential to be leveraged by all California Public Utilities Commission (Commission) -jurisdictional load-serving entities (LSE), including investor-owned utilities (IOU), electric service providers (ESP), and community choice aggregators (CCA), to save all LSEs between \$144-\$179 million each year.⁵ These cost savings

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

³ *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking (R.) 25-10-003 (Dec. 12, 2025), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M590/K884/590884355.PDF>.

⁴ *Administrative Law Judge's Ruling on Energy Division's Transactability Report and Modifying Track 1 Schedule*, R.25-10-003 (Feb. 24, 2026),

<https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=600063407>.

⁵ *California Community Choice Association's Track 1 Proposals on Transactability Issues*, R.25-10-003 (Mar. 3, 2026) (CalCCA T1 Proposals), at 8-10, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M601/K158/601158006.PDF>.

can provide relief to ratepayers, who are currently facing an affordability crisis, while maintaining reliability established through the Resource Adequacy (RA) program. Some parties agree with Energy Division's *Report on Transactability within the Slice of Day Resource Adequacy Framework* (the Report)⁶ that slice-of-day (SOD) does not impair the ability of LSEs to transact for RA capacity⁷ and therefore that LOT is not necessary at this time.⁸ Energy Division and the concurring parties understate the significant affordability benefits LOT can provide by preventing excess and unneeded LSE procurement and also overstate the complexity of the proposal. Vistra Corp. (Vistra) also makes a number of incorrect suggestions about LOT's allegedly detrimental impact on competition and market power concerns which ignore LOT's contribution to resolving market power concerns recently observed in the tight RA market.

Through extensive analysis, CalCCA has demonstrated that LOT can remove structural barriers in the market to reduce fossil reliance and promote affordability. California Environmental Justice Alliance and Sierra Club (CEJA/Sierra Club) agree, and conclude that Energy Division's concerns around LOT's "uncertain" benefits are not sufficient justification to not adopt LOT.⁹ Forward Market Design further demonstrates that Energy Division and party concerns regarding potential LOT implementation complexity are overstated and can be addressed through improvements to the Commission's RA compliance validation systems and processes.¹⁰

For these reasons, CalCCA recommends that the Commission:

- Reject Vistra's opposition to LOT, because Vistra: (1) incorrectly implies that the Commission did not intend to consider CalCCA's LOT proposal; (2) applies the wrong transactability standard in its assessment of CalCCA's proposal and the Report; (3) erroneously suggests that increasing compliance opportunities is bad for competition; and (4) improperly states that LOT can introduce market power concerns, despite LOT's ability to help resolve market power concerns recently observed in the tight RA market;
- Adopt LOT to remove structural barriers in the market to reduce reliance on fossil fuels and to promote affordability, as recommended by CEJA/Sierra Club;

⁶ *Report on Transactability within the Slice of Day Resource Adequacy Framework*, R.25-10-003 (Feb. 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M599/K960/599960179.PDF>.

⁷ See Vistra Opening Comments, at 6. All references herein to party Opening Comments are to the Opening Comments filed in this proceeding, R.25-10-003, on or about March 25, 2026.

⁸ See Middle River Power LLC (MRP) Opening Comments, at 3.

⁹ CEJA/Sierra Club Opening Comments, at 4.

¹⁰ Forward Market Design Opening Comments, at 5.

- Dismiss claims regarding the uncertainty of LOT benefits, as demonstrated by CEJA/Sierra Club; and
- Recognize Forward Market Design’s demonstration of the ability to realize LOT’s benefits while minimizing the administrative costs of implementation, thereby rejecting Energy Division’s concerns regarding complexity of implementing LOT and assertions that LOT’s benefits cannot be substantively realized in a bilateral market.

II. VISTRA’S OPPOSITION TO LOAD OBLIGATION TRADING SHOULD BE REJECTED

The Commission should reject Vistra’s opposition to LOT, because Vistra: (1) incorrectly implies that the Commission did not intend to consider CalCCA’s LOT proposal; (2) applies the wrong transactability standard in its assessment of CalCCA’s proposal and the Report; (3) erroneously suggests that increasing compliance opportunities is bad for competition; and (4) improperly states that LOT can introduce market power concerns, despite LOT’s ability to help resolve market power concerns recently observed in the tight RA market.

First, Vistra claims that “[t]he Commission did not ask whether LSEs should create a new instrument that would allow them to avoid procuring physical RA capacity to cover their own load shape. It asked whether SOD had impaired the ability to transact RA.”¹¹ This claim is misleading, as it incorrectly implies that the proposal is intended to allow LSEs to “avoid procuring physical RA capacity.” In addition, it implies that the Commission did not intend to consider CalCCA’s LOT proposal in this proceeding. To the contrary, Decision (D.) 22-06-050 explicitly states that “...if transactability and inefficiency concerns arise once the new 24-hour framework is implemented, the Commission *may consider proposals to include hourly obligation trading*.”¹² In addition, the LOT proposal does not allow LSEs to avoid procuring physical capacity. Instead, it allows them to avoid procuring *excess* physical capacity that ratepayers would need to fund without benefit. LOT trading therefore allows LSEs to optimize their procurement of physical resources in a way that makes RA procurement more cost-effective while ensuring overall requirements remain intact.

¹¹ Vistra Opening Comments, at 5.

¹² 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 23, 2022), at 97 (emphasis added), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF>.

Second, Vistra states that “LSEs remained able to procure and adjust RA capacity positions to meet their SOD obligations, without evidence of observable inefficiency or structural transactability challenges.”¹³ Like Energy Division, Vistra applies the *wrong* transactability standard, stating “[t]he relevant inquiry, then, is whether that structure still permits market participants to transact for RA capacity and comply with the system RA requirements.”¹⁴ As stated in CalCCA’s opening comments, LSEs were not, in fact, all able to comply with the system RA requirements in 2025, as Energy Division finds that even though the total system need was exceeded in every hour, some individual LSEs had deficiencies in every hour in their year-ahead (YA) filings.¹⁵ Vistra and Energy Division’s assessment of need for LOT is fundamentally flawed, by evaluating whether LOT is *necessary* for compliance rather than whether it *reduces the cost* of compliance. In doing so, Vistra ignores evidence of “observable inefficiency” challenges with the existing SOD framework.

Third, Vistra states that “the [LOT] proposal is not a mechanism to improve access to capacity sold by all market participants. It is a mechanism that allows LSEs to transact away portions of their hourly obligations among themselves rather than procure physical capacity.”¹⁶ CalCCA disagrees. LOT does improve access to capacity by making the purchased capacity used and useful, rather than forcing ratepayers to pay for excess capacity.

Vistra goes on to state that “[p]aying another LSE to take on its hourly obligation is not the same thing as securing physical capacity to support reliability. That distinction matters for competition and open access.”¹⁷ Adding products that can meet compliance obligations increases, rather than decreases, RA market competition. It is also unclear the “open access” Vistra is seeking – suppliers can continue to offer their RA-eligible capacity into the RA market, and LSEs can evaluate the combination of resource procurement and load trades that most cost-effectively meet their compliance obligations. There is nothing about the LOT proposal that

¹³ Vistra Opening Comments, at 6.

¹⁴ *Id.*, at 5.

¹⁵ See Slice of Day Transactability Workshop (Mar. 9, 2026) (Workshop Presentation), at 12.

¹⁶ Vistra Opening Comments, at 12.

¹⁷ *Ibid.*

limits open access to the transmission and distribution facilities to move bulk power from one point to another on a nondiscriminatory basis.¹⁸

Vistra also claims that only allowing LSEs to engage in LOT is discriminatory.¹⁹ Vistra points to the fact that an LSE owning an excess RA position and a non-LSE owning an excess RA position can both sell, but only an LSE can participate in LOT. This is a distinction without a difference. The only way an LSE will own a long RA position is that it either owns generation or purchases too much generation to meet its needs. On the other hand, a non-LSE does not have a compliance obligation to begin with and so has no load obligation to trade.

Fourth, Vistra states that “adopting a new product will necessitate ... ensuring market power is not exercised within the new hourly obligation market and that there are no cross-market concerns between the hourly obligation and RA capacity markets.”²⁰ LOT is intended to provide LSEs with relief from market power that can be exerted in the bilateral system RA capacity market with no market power mitigation mechanism. Indeed, more ways to transact to meet compliance obligations should *help* resolve market power concerns, not contribute to them. CalCCA analysis of Federal Energy Regulatory Commission (FERC) Electric Quarterly Report (EQR) data demonstrates that prices for RA reached over \$100 per kilowatt (kW) -month in 2024,²¹ suggesting that when physical supply is tight, the market, and ratepayers responsible for paying these exorbitant RA costs, can benefit from more options to trade, and not less.

III. HOURLY LOAD OBLIGATION TRADING SHOULD BE ADOPTED TO REMOVE STRUCTURAL BARRIERS IN THE MARKET, REDUCE RELIANCE ON FOSSIL FUELS, AND PROMOTE AFFORDABILITY, AS RECOMMENDED BY CEJA/SIERRA CLUB

CEJA/Sierra Club are concerned that the SOD program could be leading to “increased contracting of gas facilities due to the 24-hour requirements” and “increased rates due to

¹⁸ The Commission defines “open access” as, “[a] regulatory mandate to allow others to use a utility’s transmission and distribution facilities to move bulk power from one point to another on a nondiscriminatory basis for a cost-based fee.” See <https://www.cpuc.ca.gov/news-and-updates/newsroom/glossary/o>.

¹⁹ Vistra Opening Comments, at 12.

²⁰ *Id.*, at 16.

²¹ CalCCA observed three transactions (totaling 92 MW) at prices of \$100-101/kW-month for sale of capacity to California LSEs, delivered in 2024. The source of the data is CalCCA analysis of EQRs downloaded from <https://eqrreportviewer.ferc.gov/>.

contracting and market power issues.”²² These concerns are well-founded, as Energy Division finds that even though the total system need was exceeded in every hour, some individual LSEs had deficiencies in every hour.²³ To fill those open positions, the Report finds that “incremental procurement is more heavily weighted toward 24-hour resources,”²⁴ even when 24-hour resources were not needed to meet the SOD need. In fact, LSEs procured over 1,200 megawatts (MW) of 24-hour resources between the YA and MA to address a need that, in 14 hours, was less than 500 MW (and in many hours was below 250 MW).²⁵ In addition, the Report demonstrates that if storage resources were optimized through LOT, 2175 MW of thermal capacity, valued at \$24 million for a single month, could be removed.²⁶

This suggests that transactability barriers within the SOD program inhibit LSEs from optimizing their portfolios in a way that both meets overall reliability requirements *and* that they do so cost-effectively. These barriers are costly, as CalCCA estimates LOT could save all LSEs between \$144-\$179 million each year through avoided RA purchases.²⁷ As stated by CEJA/Sierra Club, “CalCCA’s analysis provides further support for removing structural barriers in the market to reduce fossil reliance and promote affordability.”²⁸

IV. ENERGY DIVISION CLAIMS THAT LOT BENEFITS ARE UNCERTAIN SHOULD BE DISMISSED, AS DEMONSTRATED BY CEJA/SIERRA CLUB

CalCCA agrees with CEJA/Sierra Club that Energy Division’s reasons for concluding LOT benefits are incremental and uncertain “[do] not provide a reason to not proceed...” with improving transactability under SOD.²⁹ Energy Division finds that the benefits of LOT are uncertain for several reasons, including impacts on CAISO backstop procurement and the local RA program.³⁰ As CEJA/Sierra Club state, these findings should be rejected as they do not provide sufficient justification not to proceed, especially given “the potential benefits of transactability and improving the program could be substantial given that the costs of RA

²² CEJA/Sierra Club Opening Comments, at 2.
²³ See Workshop Presentation, at 12.
²⁴ The Report, at 20.
²⁵ *Id.*, at 18-20.
²⁶ CalCCA Opening Comments, at 13.
²⁷ CalCCA T1 Proposals, at 8-10.
²⁸ CEJA/Sierra Club Opening Comments, at 4.
²⁹ *Id.*, at 5.
³⁰ Workshop Presentation, at 27; and the Report, at 30.

compliance exceeded \$300 million in just the May to October 2025 timeframe.”³¹ CEJA/Sierra Club also correctly note that the Report shows that storage resources were not fully optimized, and that the benefits can be expected to grow when storage is appropriately optimized.³² In addition and as stated above, Energy Division’s Report demonstrates that if storage were optimized through LOT, 2175 MW of thermal capacity, valued at \$24 million for a single month, could be removed while maintaining at least a 17 percent reserve margin in all hours.³³

CalCCA agrees with CEJA/Sierra Club that the “unclear” implications on local procurement “[do] not provide a reason not to explore transactability. Rather, this provides further evidence of the need for a more robust local procurement and planning framework...” in coordination with the IRP proceeding.³⁴ Coordination between the RA, IRP, transmission planning, and land use planning processes is required to identify the most cost-effective and feasible combinations of resources and transmission to address local needs. The need for this coordination to occur should not delay the adoption of LOT.

V. CONCERNS AROUND LOT COMPLEXITY AND ASSERTIONS THAT LOT BENEFITS CANNOT BE SUBSTANTIVELY REALIZED IN A BILATERAL MARKET SHOULD BE DISMISSED, AS DEMONSTRATED BY FORWARD MARKET DESIGN

Forward Market Design’s Opening Comments demonstrate that Energy Division and parties’ concerns around LOT’s complexity, implementation risks, and uncertain benefits should be dismissed.³⁵ CalCCA’s analysis demonstrates LOT could save all LSEs between \$144-\$179 million each year.³⁶ Even Energy Division’s analysis, which for the reasons described in CalCCA’s Opening Comments is likely understated,³⁷ finds LOT could save \$2.1 million to \$7.6 million for just one month, a saving that is not inconsequential. While Energy Division concludes that the implementation of LOT would introduce administrative complexity, the Report does not make clear, what the cost would be or whether the process can be simplified,

³¹ CEJA/Sierra Club Opening Comments, at 4.

³² *Id.*, at 6.

³³ CalCCA Opening Comments, at 13.

³⁴ CEJA/Sierra Club Opening Comments, at 4.

³⁵ *See* the Report, at 7; MRP Opening Comments, at 3; and Vistra Opening Comments, at 2.

³⁶ CalCCA T1 Proposals, at 8-10.

³⁷ CalCCA Opening Comments, at 5, 9-17.

even though “it is likely that the benefits will far exceed the costs,” as noted by CEJA/Sierra Club.³⁸

Forward Market Design recognizes that LOT could provide “meaningful savings” and puts forth several solutions to help address the risk of “implementation costs and challenges.”³⁹ Specifically, Forward Market Design states that “... a well-designed independent **SOD intermediary** could help capture the benefits of [LOT] while reducing those implementation risks[,]”⁴⁰ by providing administrative, information, and/or transactional services.⁴¹

Forward Market Design’s proposed administrative services would focus on the ability to validate LOT and could be adopted without a role for the intermediary in transactions. These administrative services would ensure that LOT is “valid and internally consistent before [these trades] are reported in RA compliance showings,” or “standardize the reporting of obligation transfers so that submissions to the Commission and Energy Division follow a consistent and verifiable format.”⁴² While Energy Division expresses concern around the complexity of validating LOTs in its existing tools, Forward Market Design demonstrates that these concerns are overstated. It is feasible for the Commission *or* an intermediary to enhance the RA program’s validation process to simplify compliance validation and reduce administrative burdens for LSEs and Energy Division staff.

Contrary to statements in the Report, the benefits of LOT are substantial, *even without an intermediary* facilitating transactions on behalf of the LSEs. CalCCA’s analysis demonstrates that 80 percent of the benefits of LOT can be achieved without an intermediary.⁴³ The Commission should therefore dismiss statements in the report suggesting that because of a lack of an intermediary, the benefits of LOT are uncertain. If the Commission is interested in achieving the full benefits *of* LOT through an intermediary, despite the bi-lateral market’s ability to achieve most of the benefits, Forward Market Design demonstrates how this could be accomplished through transactional services. These services would “facilitate the identification and pricing of potential trades between LSEs[,] help LSEs locate counterparties that are long or

³⁸ CEJA/Sierra Club Opening Comments, at 6.

³⁹ Forward Market Design Opening Comments, at 5.

⁴⁰ *Ibid.* (emphasis in the original).

⁴¹ *Ibid.*

⁴² *Id.*, at 6-7.

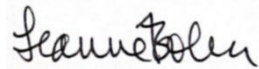
⁴³ CalCCA Opening Comments, at 14-15.

short in specific SOD hours[,] and assist in price discovery.”⁴⁴ Again, transactional services offered by an intermediary are likely *not* a prerequisite for achieving the majority of benefits of LOT, but could be utilized to further realize the complete benefits of LOT.

VI. CONCLUSION

CalCCA respectfully requests consideration of the comments herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

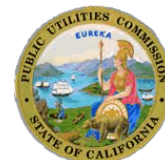


Leanne Bober,
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General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

March 30, 2026

⁴⁴ Forward Market Design Opening Comments, at 6.



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

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Order Instituting Rulemaking to Oversee the
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Establish Forward Resource Adequacy
Procurement Obligations.

R.25-10-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON TRACK 1 PROPOSALS**

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March 20, 2026

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SUMMARY OF RECOMMENDATIONS¹

CalCCA recommends that the Commission:

- Take prompt action to address the significant forthcoming impacts of data center loads on RA requirements, as highlighted by parties;
- Adopt CalCCA’s proposal for EO resources, as it is unnecessary to delay adoption until after CAISO study as recommended by the CAISO and Cal Advocates;
- Dismiss PG&E’s recommendation to reject CalCCA’s proposed local RA data request process clarifications;
- Adopt CalCCA’s proposed local RA data request transparency enhancements, which explicitly address PG&E’s requested clarifications;
- Reject PG&E’s proposal to remove the LCR-RCM because, as CEJA and Sierra Club state, no viable alternative was proposed to replace it;
- Reject Energy Division and SCE’s proposals on IR and RC bidding and revenue allocation, as recommended by multiple parties;
- Reject Hydrostor’s proposal to not apply unforced capacity (UCAP) to existing resources under long-term contract;
- Reject the CAISO’s recommendations on how to account for storage in the QC in favor of CalCCA’s alternative methodology that more accurately accounts for foldback under SOD; and
- Reject Cal Advocates’ LDES counting proposal because, as stated by multiple parties, it may underestimate LDES’ charging capability.

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.25-10-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON TRACK 1 PROPOSALS**

California Community Choice Association² (CalCCA) submits these reply comments on Track 1 proposals pursuant to the *E-Mail Ruling Modifying Track 1 Schedule*³ (Ruling), dated February 9, 2026.

I. INTRODUCTION

The California Public Utilities Commission's (Commission) Resource Adequacy (RA) program plays a critical role in ensuring reliability in the California Independent System Operator (CAISO) balancing authority area. Program rules, however, can impose significant costs on California customers. Party Opening Comments demonstrate the need to carefully consider proposals that address the methodologies for allocating RA requirements, establishing resource

² California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, 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 *E-Mail Ruling Modifying Track 1 Schedule*, Rulemaking (R.) 25-10-003 (Feb. 9, 2026), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M599/K056/599056589.PDF>.

eligibility and counting, and administering the local RA central procurement entity (CPE) procurement framework to ensure reliability requirements are met in a cost-effective manner.⁴

First, Party Opening Comments highlight that the likely significant impacts of data center loads on RA requirements necessitate prompt action to determine how to treat data centers in the RA allocation process. Party comments opposing CalCCA's data center RA proposal should therefore be rejected, given CalCCA's proposal sets RA requirements for data center loads reliably and accurately, maintains compatibility with downstream processes, and provides a procedural pathway for addressing data center RA allocation issues using the collaborative process between the Commission and the California Energy Commission (CEC).

Second, many parties support energy-only (EO) resources playing a larger role within the RA program as a way to increase the resources eligible to charge storage resources under the slice-of-day requirements. While some parties express concern that such proposals would create reliability issues by deviating from the RA program's foundational deliverability principles, CalCCA's EO proposal is designed specifically to adhere to these principles by ensuring deliverability limits at the point-of-interconnection (POI) level are respected.

Third, party comments also provide recommendations on the local RA CPE framework. While Pacific Gas and Electric Company (PG&E) opposes CalCCA's proposal to clarify the use of the local RA data request process, other parties correctly note that the proposal has transparency and affordability benefits that should not be ignored. Parties also highlight that PG&E has not sufficiently demonstrated a need to remove or proposed a viable alternative for the Local Capacity Requirement – Reduction Compensation Mechanism (LCR-RCM).

⁴ References herein to "Opening Comments" refer to those filed on or about March 6, 2026, on Track 1 Proposals in R.25-10-003. References herein to "proposals" refer to those filed on or about Jan. 23 2026, in R.25-10-003.

Fourth, a broad range of parties also oppose Energy Division's proposal for the Commission to interfere with how load-serving entities (LSE) and suppliers treat revenues from the CAISO's imbalance reserves (IR) and reliability capacity (RC) products. These parties correctly recognize that this proposal is an ineffective way to address the Commission's double counting concerns.

Finally, various recommendations are made regarding counting rules for resources with forced outage or foldback. The Commission should assess these proposals based upon how they account for those resources' individual contributions to reliability and how they align with the slice-of-day (SOD) program.

The Reply Comments herein recommend, in summary, that the Commission:

- Take prompt action to address the significant forthcoming impacts of data center loads on RA requirements, as highlighted by parties;
- Adopt CalCCA's proposal for EO resources, as it is unnecessary to delay adoption until after CAISO study as recommended by the CAISO and Cal Advocates;
- Dismiss PG&E's recommendation to reject CalCCA's proposed local RA data request process clarifications;
- Adopt CalCCA's proposed local RA data request transparency enhancements, which explicitly address PG&E's requested clarifications;
- Reject PG&E's proposal to remove the LCR-RCM because, as California Environmental Justice Alliance CEJA and Sierra Club (CEJA/Sierra Club) state, no viable alternative was proposed to replace it;
- Reject Energy Division's and Southern California Edison Company's (SCE) proposals on IR and RC bidding and revenue allocation, as recommended by multiple parties;
- Reject Hydrostor, Inc.'s (Hydrostor) proposal to not apply unforced capacity (UCAP) to existing resources under long-term contract;
- Reject the CAISO's recommendations on how to account for storage in the qualifying capacity (QC) in favor of CalCCA's alternative methodology that more accurately accounts for foldback under SOD; and

- Reject Cal Advocates’ long duration energy storage (LDES) counting proposal because, as stated by multiple parties, it may underestimate LDES’ charging capability.

II. PARTY COMMENTS HIGHLIGHT SIGNIFICANT FORTHCOMING IMPACTS OF DATA CENTER LOADS ON RA REQUIREMENTS, NECESSITATING PROMPT ACTION

Several parties acknowledge the significant impact and uncertainty data centers will have on the load forecast process.⁵ CalCCA’s proposal is intended to manage, as SDG&E states, the “severe risk of load forecast inaccuracy driven by uncertain and speculative data center interconnections.”⁶ It does so by including data center load in RA requirements based upon actual interconnection information once they meet certain milestones, such as the selection of an LSE generation provider, an executed interconnection agreement, and a verified interconnection date within the RA year.

CEJA/Sierra Club and SDG&E support CalCCA’s proposal due to its ability to protect ratepayers. CEJA/Sierra Club note that it is important for the Commission to “examine how to meet data center load in a way that does not hinder affordability concerns.”⁷ SDG&E “supports the intention of CalCCA’s proposal: to safeguard against upward rate pressure driven by ‘too high of a forecast [which] can result in substantial procurement costs with little or no additional load to spread those costs.’”⁸

Other parties’ opposition to the proposal should be rejected given they: (1) incorrectly assume CalCCA’s proposal would not set RA requirements reliably and accurately; (2) incorrectly assert that CalCCA’s proposal is incompatible with downstream processes; and (3)

⁵ CEJA/Sierra Club Opening Comments, at 12; San Diego Gas & Electric Company (SDG&E) Opening Comments, at 6-7; and Middle River Power LLC (MRP) Opening Comments, at 26.

⁶ SDG&E Opening Comments, at 6-7.

⁷ CEJA/Sierra Club Opening Comments, at 12.

⁸ SDG&E Opening Comments, at 7.

incorrectly imply that the RA proceeding is the wrong procedural pathway to address data center RA allocation issues.

1. MRP and PG&E are Incorrect in Their Assumptions that CalCCA’s Proposal Would Not Set RA Requirements Reliably and Accurately

MRP acknowledges that “CalCCA correctly identifies uncertainty associated with forecasting data center load.”⁹ However, MRP incorrectly claims that “separating that load from the Integrated Energy Policy Report (IEPR) forecast would introduce significant reliability risk and undermine the Commission’s planning framework.”¹⁰ CalCCA’s proposal would not separate the load from the IEPR forecast overall. Instead, it would create a parallel path specific to the forecast used for setting RA requirements to ensure that large data center loads are correctly attributed and reflect loads that will actually come online. As stated by CEJA/Sierra Club, who support CalCCA’s proposal, “RA, unlike IRP, looks ahead at a shorter timeline, and it is highly unlikely that loads that have not met some predetermined milestones will come online in the RA timeline.”¹¹

MRP’s concern with resource retention under CalCCA’s proposal is misplaced. CalCCA is not proposing to extend its proposal to longer-term planning functions such as Integrated Resource Plan (IRP) and Transmission Planning Process (TPP). CalCCA anticipates that the Commission will need to consider how to treat data center loads for mid- to long-term resource planning in the forthcoming Reliable and Clean Power Procurement Program (RCPPP) process. However, the RA framework’s short time horizon allows the Commission the ability to use milestones, rather than a forecast, to determine which data center loads to include in the RA requirements based on the likelihood they will interconnect during the RA year.

⁹ MRP Opening Comments, at 26.

¹⁰ *Ibid.*

¹¹ CEJA/Sierra Club Opening Comments, at 12.

PG&E states that the CEC's existing econometric model likely accounts for some level of uncertainty of new data center load.¹² While this may be true, probabilistic assumptions are not conducive to the development of RA requirements including data center loads. Data center loads are often very large and discrete. For example, one data center with 1,000 megawatts (MW) peak load could double an LSE's RA requirement. Using probabilistic assumptions to account for uncertainty of small quantities of very large loads can cause significant load forecast inaccuracies if those assumptions deviate from reality. Probabilistic assumptions about the amount of data center loads interconnecting in the RA year risk significant over- or under-forecasting for certain LSEs, even if only one data center changes its interconnection status for the RA year. System RA requirements are set a year in advance for one year forward, meaning actual data center load interconnection information can--and should--be used to set RA requirements rather than assumptions.

2. CalCCA's Data Center Proposal is Compatible with Downstream Processes, Contrary to MRP's Assertions

MRP also states that separating data center load from the IEPR forecast could undermine local reliability, given that data centers are often geographically concentrated and can materially affect local area capacity needs.¹³ CalCCA disagrees. Local RA requirements are set through a separate CAISO process evaluating how contingencies impact the amount of local resources needed to serve local area load. Even if the CAISO chooses to use the IEPR load forecast for this process, a one MW increase in load does not always equate to a one MW increase in local requirements. Additionally, most local areas – including those with large amounts of forecasted data center loads – are addressed through central procurement allocated to all LSEs in the local

¹² See PG&E Opening Comments, at 19.

¹³ See MRP Opening Comments, at 27.

area. Many local areas where data centers are anticipated do not have a surplus of local resources, meaning additional resources will very likely be procured by LSEs or CPEs. If not procured by LSEs or CPEs, the CAISO can backstop to meet local reliability needs. Longer term, local reliability will need to be addressed through the IRP and TPP processes to ensure sufficient generation and transmission to meet local reliability needs.

MRP also states that CalCCA’s proposal fails to account for other downstream impacts, including import allocation rights (IAR) and congestion revenues rights (CRR).¹⁴ If the allocation of IARs and CRRs is done based upon the forecast that differs from the obligations set for LSEs procure RA due to the unique treatment of data center loads, for most LSEs, the differences will be small. That is, the impact to eligible quantities for IARs and CRRs, which will be updated the following year if the load IEPR load forecast is correct, pales in comparison to the cost of procured RA for a data center load that does not materialize. For others, the certainty around the data center loads included in their obligations is likely more important than having the maximum import capability and CRRs perfectly match. Should this mismatch occur, LSEs have opportunities to buy and sell both import allocation rights and CRRs.

3. PG&E’s and Vistra’s Opposition to CalCCA’s Proposal on Procedural Grounds Should be Rejected

PG&E and Vistra Corp. (Vistra) both question the RA proceeding as the venue to address this issue and instead recommend this issue be address in the CEC’s IEPR process.¹⁵ PG&E incorrectly suggests that CalCCA’s proposal would “sidestep the CEC’s role” in demand forecasting by adopting a “standalone allocation of RA procurement responsibility process in the RA proceeding, distinct from the CEC’s IEPR load forecasting process.”¹⁶ This statement

¹⁴ *See Ibid.*

¹⁵ PG&E Opening Comments, at 18-19.

¹⁶ *Id.*, at 19.

mischaracterizes CalCCA's proposal and should be dismissed. The Commission and CEC work collaboratively to set RA requirements, as demonstrated by Energy Division's proposal on load forecasting.¹⁷ Through the existing load forecast adjustment process, which has been established and modified over the course of various Commission decisions,¹⁸ the CEC determines the peak demand forecast via the IEPR and LSE-specific forecasts used to set the RA requirements. The Commission sets the RA obligation framework and administers compliance and enforcement.

CalCCA's proposal is specifically intended to leverage this collaborative process between the two agencies and does not necessitate modifications to how the CEC establishes the peak demand forecast. Instead, it adds a step to the end of the process to separate data centers from that process so that actual interconnection information can inform the data center RA allocations. The Commission should therefore dismiss claims that CalCCA's proposal is a "standalone" effort to "sidestep" the CEC.

Vistra recommends a cross-entity workshop within the 2026 IEPR where load forecast issues can be explored.¹⁹ CalCCA is not opposed to such a workshop and welcomes collaboration with the CEC and other stakeholders on this issue. However, the effects of data center load are already materializing in the RA forecasts and are expected to grow significantly in the forthcoming years. The magnitude and immediacy of this issue necessitate prompt resolution to ensure data center load is allocated to the right LSEs in the right quantities. The Commission should therefore adopt CalCCA's proposal in its forthcoming June decision. If additional implementation details need to be resolved, the Commission should adopt SDG&E's

¹⁷ Energy Division Proposal, at 6-13.

¹⁸ Id., at 6: "This proposal summarizes the existing RA load forecast adjustment process adopted in D.04-10-35 and subsequently modified in D.05-10-042, D.09-06-028, D.10-03-022, D.10-12-038, D.11-06-022, D.12-06-025, D.14-06-050, D.15-06-063, D.16-06-045, D.17-06-027, and D.18-06-030."

¹⁹ See Vistra Opening Comments, at 19.

recommendation to “require that further comments and/or workshops be conducted to address this and other critical large load-related issues.”²⁰ Delaying consideration of these issues would expose ratepayers to significant risks of forecast inaccuracy given the impacts of data center loads are predicted to be much more substantial in the 2026 IEPR demand forecast and beyond.

III. RECOMMENDATIONS TO DELAY THE ADOPTION OF EO PROPOSALS IS NOT NECESSARY FOR CALCCA’S PROPOSAL, WHICH IS LIMITED TO EO CAPACITY LOCATED AT DELIVERABLE POIS

Many parties support various ways to increase the role of EO resources in RA.²¹ While the details of the proposals vary, the objectives are consistent: enhancing the ability of EO resources to provide reliability value in the RA program, thereby increasing the amount of available supply able to meet SOD requirements.

The parties that oppose these proposals do so because they assume the proposals do not ensure resources providing RA or charging sufficiency will be deliverable.²² For example, Western Power Trading Forum (WPTF) states that, “...every pending proposal rests on a critical but untested assumption: that EO resources—by definition lacking full capacity deliverability status—will be available and deliverable to provide charging energy to storage resources during non-AAH/off-peak hours.”²³ In limiting its proposal to EO resources co-located with a deliverable resource, CalCCA’s proposal accounts only for EO resources located at a POI that has already been assessed for and allocated deliverability under the CAISO’s existing

²⁰ SDG&E Opening Comments, at 7.

²¹ See American Clean Power – California Proposal, at 3-15; CalCCA Proposal, at 7-11; the California Energy Storage Alliance, the Large-Scale Solar Association, the Solar Energy Industries Association, and the California Wind Energy Association Proposal, at 1-13; PG&E Proposal, at 1-7; SCE Proposal, at 7-10; and Sonoma Clean Power Authority Proposal, at 5-10.

²² See CAISO Opening Comments, at 1-2; Cal Advocates Opening Comments, at 2-4; MRP Opening Comments, at 17-19; and WPTF Opening Comments, at 10-12.

²³ WPTF Opening Comments, at 11.

methodology. By limiting RA counting in such cases to be capped by the deliverability limit at the POI, CalCCA's proposal *does* ensure existing deliverability standards are met.

The CAISO and Cal Advocates recommend the Commission not adopt any of the proposals related to EO resources until the CAISO completes its study in the TPP that will provide information on the ability for EO resources to charge storage.²⁴ It is unnecessary to wait to adopt CalCCA's proposal because it does not extend beyond locations that have already been studied and classified as deliverable under the CAISO's existing deliverability assessment methodology, where the amount shown for RA SOD does not exceed the deliverability at the POI in any hour.

IV. PG&E'S RECOMMENDATION TO REJECT CALCCA'S PROPOSAL TO CLARIFY THE USE OF THE LOCAL RA CPE DATA REQUEST SHOULD BE DISMISSED

The Commission should reject PG&E's recommendation to reject CalCCA's proposal to clarify the use of the local RA CPE consistent with approach used by SCE. PG&E states that this issue has already been contemplated by the Commission and CalCCA has not presented new facts.²⁵ To the contrary, this issue was last considered by the Commission *before* the CPEs' Annual Compliance Reports documented how the local RA data request results were first used by the CPEs.²⁶ Since then, it has been revealed that the CPEs appear to use the data differently to inform their procurement decisions, necessitating clarification to ensure consistency across CPE areas and certainty for LSEs whose portfolios are impacted by CPE procurement.

PG&E also appears to object to SCE's method for using the data request results, stating:

²⁴ CAISO Opening Comment, at 1-2; and Cal Advocates Opening Comments, at 2-4.

²⁵ PG&E Opening Comments, at 14-15.

²⁶ D.25-06-048, *Decision Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements*, R.23-10-011 (June 27, 2025), at 95-96.

[T]he Commission recognized that there is no guarantee that local RA resources reported in the data aggregation will remain under contract or be shown to the CAISO, so explicitly reducing a CPE's requirements on a 1-for-1 MW basis could result in an inaccurately low requirement that does not sufficiently provide for local RA reliability. In addition, explicitly defining a CPE's requirements by netting out the local RA capacity data on a 1-for-1 MW basis would restrict LSEs' ability to bid local resources into the CPEs' solicitations.²⁷

Effectively, PG&E is advocating for LSE uncertainty to close out an open position, while ignoring that the LSE uncertainty is unnecessary because the CAISO can backstop local-area deficiencies if the CPE is deficient and LSE procurement does not cover the deficiency. In cases where the resources needed for the local area are under contract to an LSE that needs that capacity to meet system requirements, they are likely being shown, so the CAISO does not need to backstop. Indeed, even with the shortfalls PG&E has experienced as the CPE, the CAISO has not conducted CPM for a local area deficiency.

In addition, CalCCA agrees with MRP that both CPEs using SCE's approach would "improve transparency and align procurement responsibilities with actual system needs..., better preserve LSE procurement autonomy by ensuring that capacity already under contract is recognized before the CPE enters the market..., and protect ratepayers..."²⁸ For these reasons, the Commission should reject PG&E's recommendation and adopt CalCCA proposal.

V. ADDITIONAL INFORMATION IS NOT NEEDED BEFORE THE COMMISSION ADOPTS CALCCA'S PROPOSAL FOR LOCAL RA DATA TRANSPARENCY AS PG&E SUGGESTS

PG&E states that it does not oppose CalCCA's proposal for increased transparency of the local RA CPE data request results but requests a number of clarifications before it is adopted. As

²⁷ PG&E Opening Comments, at 16 (footnotes omitted).

²⁸ *Id.*, at 30-31.

stated by PG&E, Decision (D.) 24-12-003²⁹ authorizes Energy Division to collect the following information from LSEs about its local RA capacity under contract: (1) Resource ID; (2) local area; (3) contract start and end date; (4) resource technology type; and (5) contracted quantities of capacity in MW for the 3-year forward period.³⁰ Energy Division then aggregates and anonymizes the information. It then provides this aggregated and anonymized information, along with Resource ID information without the LSE-identifying information, to the CPEs.³¹ CalCCA's proposal recommends the Commission provide the same information to LSEs that it provides to the CPEs, including all the same categories of information, time period of information, and types of information (e.g., contracted MW and technology type).

The Alliance for Retail Energy Markets (AReM) supports CalCCA's proposal, provided the data is released to LSEs coincident with CPEs.³² CalCCA concurs. The information should be released to LSEs at the same time as it is provided to the CPEs. CalCCA is open to how the information is publicized, as long as it is publicized in a timely manner consistent with when the CPEs receive the data. One option would be for Energy Division to post the information on the Commission's website.

VI. THE COMMISSION SHOULD NOT REMOVE THE LCR-RCM FOR THE REASONS STATED BY CEJA/SIERRA CLUB AND MRP

Ava Community Energy and Peninsula Clean Energy Authority (the Joint CCAs), CalCCA, MRP, and CEJA/Sierra Club all oppose PG&E's proposal to remove the LCR-RCM.³³ MRP notes that because not all resources are eligible for LCR-RCM, a small number of

²⁹ D.24-12-003, *Decision on Track 2 Issues*, R.23-10-011 (Dec. 5, 2024).

³⁰ PG&E Proposal, at 17.

³¹ *See* D.24-12-003.

³² AReM Opening Comments, at 9.

³³ Joint CCA Opening Comments, at 14-15; CalCCA Opening Comments, at 16-18; MRP Opening Comments, at 23-24; and CEJA/Sierra Club Opening Comments, at 5-7.

resources seeking compensation should be expected and is not an indication of the program's ineffectiveness.³⁴ MRP is correct, and their position is supported by the Commission decision adopting LCR-RCM, D.20-12-006.³⁵ In D.20-12-006, the Commission expressed concern that if LCR-RCM was open to existing preferred and storage resources, those existing resources alone would represent 36 percent of the local area need at that time.³⁶ Restricting the resources to only new preferred and storage resources was developed to, "... incentivize, or at the very least not allow the CPE framework to discourage, LSE development of new preferred or energy storage resources in local areas to meet their system or flexible RA requirements."³⁷ Without any mechanism to compensate LSEs for bringing new preferred or storage resources to commercial operation within the local area, PG&E's proposal will discourage procurement of clean local area resources, contrary to the intention of D.20-12-006.

CEJA/Sierra Club note that PG&E does not propose any mechanism to replace LCR-RCM, and that the lack of incentive mechanisms will not: (1) assist with the necessary reduction in air pollution; (2) reduce the market power of existing local area resources potentially impacting affordability; (3) replace aging plants with increasing outage rates particularly during heat events when reliability is at its most precarious; or (4) meet SB 887³⁸ to reduce local air pollution in disadvantaged communities.³⁹ Indeed, all four items are similarly prescribed in Public Utilities Code section 380 which requires the Commission to, "... ensure the reliability of electrical service in California while advancing, to the extent possible, the state's goals for clean

³⁴ MRP Opening Comments, at 23-24.

³⁵ D.24-12-006, *Decision Freezing Specific Support Amount*, R.20-02-008 (Dec. 5, 2026).

³⁶ D.20-12-006 at 18-19.

³⁷ *Id.*, at 20.

³⁸ Senate Bill 887 (SB 887) (Becker, Stern, Ch. 358, Stats. of 2022).

³⁹ CEJA/Sierra Club Opening Comments, at 5-7.

energy, reducing air pollution, and reducing emissions of greenhouse gases.”⁴⁰ Section 380 goes on to list multiple objectives which include, the “[f]acilitat[ion of] the development of new generating, nongenerating, and hybrid capacity and the retention of existing generating, nongenerating, and hybrid capacity that is economical and needed for reliability and to achieve the state policy specified in Section 454.53.” and “[c]onsideration of mitigation measures, if the commission determines they are needed, to reduce costs to ratepayers.”⁴¹

Importantly, as pointed out by MRP, PG&E has not identified market power concerns that have been exercised through the LCR-RCM, and the premium for local area resources is simply the difference between system RA value and local area RA CPE weighted average cost in the local area.⁴² Since the CPE can reject bids to provide local RA due to prices indicative of market power, it is unlikely that the premium reflected in the LCR-RCM is due to market power, but rather to the costs of locating and maintaining a resource within a constrained local area. Indeed, with system RA prices lacking such a mechanism to avoid market power, it is not surprising that the prices for local area and system are converging.⁴³ If PG&E is correct that market power is driving the fundamental prices used to determine the local area premium, then the Commission should review not only market power in the local area but market power on system resources to ensure that the LCR-RCM is neither overstated nor understated.

The Joint CCAs highlight other considerations that may have reduced participation in LCR-RCM. Importantly, this includes the new implementation of SOD, which has required considerable resources from LSEs. As these CCAs describe, as this implementation progresses

⁴⁰ Calif. Pub. Util. Code § 380.

⁴¹ *Ibid.*

⁴² D.20-12-006, at 18.

⁴³ <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/lcr-rcm-2025.pdf>, at 2

and the program stabilizes, participation in LCR-RCM may increase.⁴⁴ While this may be true, the Commission must keep in mind that participation is limited to new preferred and storage resources in the local area, which will always keep participation relatively low.

SCE supports the elimination of LCR RCM, asserting that “the LCR-RCM adds procedural complexity without a corresponding policy benefit. Adopting PG&E’s proposal would create a unified, streamlined RA implementation framework across CPE service areas and further the Commission’s goal of improving transparency and reducing administrative overhead.⁴⁵” However, neither PG&E nor SCE has stated how much the administrative overhead has cost. Without data on the avoidable costs, a cost-benefit calculation cannot be performed. If the CPE is not receiving any requests or a very limited set of requests for LCR RCM, it is difficult to believe that there is a significant cost to execute this option. Absent better information on costs, as well as determining if the current participation level will continue or improve, the Commission should reject PG&E’s proposal to eliminate the LCR RCM.

VII. PARTY OPENING COMMENTS SUPPORT THE REJECTION OF SCE AND ENERGY DIVISION PROPOSALS REGARDING IR/RUC BIDDING AND REVENUE ALLOCATION REQUIREMENTS

Many parties oppose Energy Division’s proposal to require zero dollar bid prices and the reallocation of revenues for the IR and RC products.⁴⁶ These parties recognize that the allocation of IR and RUC revenues can be best addressed by counterparties negotiating on their own behalf to address Energy Division’s concerns arounds double payment concerns. Notably, AReM changed its position from supporting the Energy Division proposal to supporting an alternative

⁴⁴ Joint CCA Opening Comments, at 14.

⁴⁵ SCE Opening Comments at 19.

⁴⁶ See Opening Comments from AES, AReM, Joint CCAs, Calpine LLC, Independent Energy Producers Association, PG&E, REV Renewables, LLC, SDG&E, Vistra, and WPTF.

that allows the buyer and seller to negotiate the best terms possible without the Commission prescribing a “one-size-fits-all revenue flow requirement.”⁴⁷”

AES Corporation (AES) states that it, “...supports CAISO's counterproposal that LSEs and suppliers should be free to negotiate these allocations in their bilateral RA contracts, consistent with standard market principles and the practical realities of contracting in the EDAM environment.”⁴⁸ The practical realities AES refers to are enumerated in CalCCA Opening Comments, including the administrative burden of settlements, the zero-sum game nature of contractual capacity prices, and the revenues available from the market, where if the seller observes fewer revenues from the market.⁴⁹ Energy Division’s proposal will increase the capacity price and the parties' ability to negotiate subsequent deals with full knowledge of their positions and exposure to upstream payment stream requirements.

The Department of Market Monitoring (DMM) advocates requiring a zero-dollar bid, as it reflects the marginal cost of the resource that has already sold its capacity via RA to an LSE. This ignores that a selling entity may have the opportunity to sell its capacity to a variety of entities, including the CAISO, through IR and RC. The question then is which party, the CAISO, or an LSE off taker of RA, is covering the seller's marginal cost? DMM assumes it is the RA buyer but has no reason to do so. Simply stated, sellers will estimate the value of the IR/RC they expect to sell, along with any rents from energy sales that can cover their fixed capacity costs, and then offer RA at that expected value in a competitive market. If another seller assesses that it will obtain more IR/RC and energy market rents, it can offer its RA capacity at a lower cost. Restricting buyers from allowing entities to engage in this competitive process effectively

⁴⁷ AReM Opening Comments, at 9-10.

⁴⁸ AES Opening Comments, at 7.

⁴⁹ PG&E referred to this very issue in its Opening Comments, at 13-14.

assumes that the resource will not obtain any IR/RC or market rents, and will increase the price paid for RA. Market participants, including buyers, are best positioned to determine the optimal outcome rather than a Commission-prescribed methodology.

VIII. HYDROSTOR'S PROPOSAL TO NOT APPLY UCAP TO RESOURCES WITH EXISTING LONG-TERM CONTRACTS SHOULD BE REJECTED

While CalCCA appreciates Hydrostor's concerns about implementing UCAP for existing resources, the discussion of UCAP has been ongoing since at least September 2005, when the CAISO filed comments on the Commission's Capacity Market White Paper.⁵⁰ While CalCCA supports refining UCAP and ensuring that resources are attributed the correct value as Hydrostor requests, grandfathering resources with existing long-term contracts does not seem necessary. Parties entering into contracts have, or should have, known for many years prior to this proceeding that UCAP is a well-established measure of reliability and can be implemented in California.

Common practice in the California RA market is to denominate RA deals in NQC. Because NQC represents the reliable capacity a resource can provide, it is appropriate for the UCAP to determine a resource's NQC. If grandfathering results in an NQC value higher than it would under UCAP, the result will be either a fleet that does not meet the one-in-ten reliability standard or a PRM that is higher to account for those resources being over-valued. Since the purpose of UCAP is to maintain resources by recognizing their contribution to reliability, accounting for their forced outage rate, grandfathering would result in exactly the opposite, with the system as a whole accounting for the true reliability value of grandfathered resources rather than the resource and off taking LSE. For these reasons, the Commission should not adopt Hydrostor's proposal.

⁵⁰ *Opening Comments of the California Independent System Operator Corporation on the California Public Utilities Commission's Capacity Markets White Paper*, R.04-04-003. The term "UCAP" appears 182 times.

IX. THE CAISO'S RECOMMENDATIONS ON HOW TO ACCOUNT FOR STORAGE FOLDBACK IN THE QC SHOULD BE REJECTED

The CAISO's recommendations on how to address foldback in the QC is based on its view that RA is still a peak-load assessment, not an hourly assessment like the Commission's SOD. As such, the CAISO is constrained by its own processes, which use a continuous four-hour discharge. For a resource with foldback, the average of four hours will be lower than its peak capability.

The CAISO's use of four continuous hours was developed around the notion that predicting the exact hour of the peak load may not be completely accurate. Four hours of continuous output would help ensure the CAISO could dispatch the resource to meet the peak load. However, this accounting exercise has always been divorced from actual market operations. That is, a resource must offer a minimum quantity but can bid and be dispatched above that capability. SOD recognized that accounting for loads and resources on a peak-load basis, with MCC Buckets to ensure all load hours are met, was inaccurate. For example, the move to SOD recognized that a solar resource would not deliver its ELCC value in non-daylight hours (*i.e.*, its average reliability over 24 hours based on its ability to meet a one-in-ten loss-of-load event). Similarly, batteries should not be penalized when they can provide higher reliability than their average in a given hour under SOD, where the objective was to become more accurate in depicting the reliability benefit of resources.

Instead, the Commission should adopt CalCCA's alternative methodology to more accurately reflect foldback under SOD,⁵¹ and continue to work with the CAISO to ensure that the CAISO's accounting is consistent with SOD rather than changing its counting to artificially reduce the reliability value of battery storage resources. CalCCA's alternative methodology would allow a resource to count for full capacity in some hours and a derated amount in other

⁵¹ CalCCA Proposal, at 14-16.

hours as long as the total megawatt hours shown does not exceed the resource’s capability subject to foldback. CalCCA has and will continue working with the CAISO through their Storage Modeling and Design stakeholder process to address this very concern.⁵²

X. CAL ADVOCATES’ LDES COUNTING PROPOSAL SHOULD BE REJECTED BECAUSE IT LIKELY UNDERESTIMATES LDES’ CHARGING CAPABILITY, AS STATED BY MULTIPLE PARTIES

CalCCA agrees with the several parties that express concern with Cal Advocates’ proposal to count LDES resources assuming charging capacity comes from four preceding days in which the supply and load conditions are the same as the “worst day” SOD load and supply conditions for the compliance month.⁵³ As stated by the Joint Parties, Cal Advocates proposal is “...built on the flawed premise that [LDES] must find its fuel on the very day the grid is most stressed.”⁵⁴ Given this, CalCCA agrees with SCE that by requiring a forward charging period of only four days, Cal Advocates’ proposal “... may underestimate the charging energy available to LDES in the days and weeks preceding stressed periods.”⁵⁵ CalCCA also agrees with parties that state that a zero percent initial state-of-charge (SOC) assumption for LDES as proposed by Cal Advocates is overly restrictive and unrealistic from an operational perspective. As SCE explains, “LDES resources are likely to maintain a moderate level of SOC, both to be well-positioned to take advantage of grid stress periods and to ensure the longevity of their technology.”⁵³ Given the strong opposition to these unrealistic underlying assumptions, CalCCA again requests that the Commission reject Cal Advocates’ proposal.

⁵² <https://stakeholdercenter.caiso.com/Comments/AllComments/7ebde4c4-2e11-413b-a307-d130a5313c5c#org-c6b84df7-a546-4955-b92b-0db4d501d19c>.

⁵³ California Energy Storage Alliance, Form Energy, Hydrostor, and Fourth Power (Joint Parties) Opening Comments, at 3-16; Hydrostor Opening Comments, at 6-7; and SCE Opening Comments, at 16.

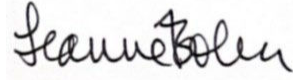
⁵⁴ Joint Parties Opening Comments, at 16.

⁵⁵ SCE Opening Comments, at 16.

XI. CONCLUSION

CalCCA respectfully requests consideration of the comments herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

A handwritten signature in black ink that reads "Leanne Bober". The signature is written in a cursive style with a large initial "L".

Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

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**STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION**

IN THE MATTER OF:

*Preparation of the 2026 Integrated Energy
Policy Report (IEPR) Update*

DOCKET NO. 26-IEPR-01

RE: Scoping Order

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE
DRAFT SCOPING ORDER FOR THE 2026 INTEGRATED ENERGY POLICY
REPORT UPDATE**

Leanne Bober,
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**STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION**

IN THE MATTER OF:

*Preparation of the 2026 Integrated Energy
Policy Report (IEPR) Update*

DOCKET NO. 26-IEPR-01

RE: Scoping Order

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE
DRAFT SCOPING ORDER FOR THE 2026 INTEGRATED ENERGY POLICY
REPORT UPDATE**

The California Community Choice Association¹ (CalCCA) submits these comments pursuant to the *Notice of Request for Comments on the Draft Scoping Order for the 2026 Integrated Energy Policy Report Update*² (Notice), dated March 10, 2026.

I. INTRODUCTION

The Draft Scoping Order for the 2026 Integrated Energy Policy Report Update (Scoping Order) puts forth the following scoping items for the 2026 Integrated Energy Policy Report (IEPR) Update: (1) California electricity demand forecast; (2) California geothermal resources; and (3) energy equity and environmental justice. CalCCA supports including these items in the

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

² *Notice of Request for Comments on the Draft Scoping Order for the 2026 Integrated Energy Policy Report Update*, 26-IEPR-01 (Mar. 10, 2026):

<https://efiling.energy.ca.gov/GetDocument.aspx?tn=268981&DocumentContentId=106175>.

scope and appreciates the efforts of the California Energy Commission (Commission) to develop the IEPR each year, which serves as a foundational document for California's energy policy.

The scope of analysis undertaken by Commission staff to develop the IEPR is a significant undertaking under any scenario. Current fluctuating policy, technological, and market forces further complicate this difficult task. To ensure forecasted load growth reflects the best-known information at the time of forecast development, the Commission should seek information from all knowledgeable stakeholders to inform the likelihood and timing of large load interconnections. Community choice aggregators (CCAs) are well-positioned to evaluate new load growth given their unique access to information, either from large load customers or their local permitting agencies. Consulting with CCAs, along with the investor-owned utilities (IOU) and large load customers, will ensure information used to develop the forecast is as accurate as possible.

The Scoping Order indicates that the 2026 IEPR Update will include an assessment of the impacts from utility energization applications (known loads) data and discussion around how to include these loads in the forecast. Given known loads are inherently uncertain, to the extent the Commission considers including known loads in the forecast, the Commission should continue to exclude them from the Planning Forecast. Incorporating known loads is not necessary for the Planning Forecast given its intended purpose.

The Scoping Order also states that the Commission will explore challenges and opportunities for geothermal development in California. Geothermal resources have the potential to play a significant role in the State's clean energy transition by providing clean baseload energy. Despite interest from LSEs and regulators in geothermal procurement, the amount of geothermal projects in the interconnection queue does not reach the levels included in planning

portfolios. The Commission should therefore seek to identify and reduce barriers that may be preventing geothermal development to the levels assumed in planning.

In summary, CalCCA recommends the Commission:

- Solicit information on new loads from all informed stakeholders including CCAs to inform the likelihood and timing of large loads before including them in the forecast;
- Coordinate with the California Public Utilities Commission (CPUC) to adopt a formal process for allocating RA obligations for data center load based on actual interconnection information and milestones;
- To the extent the Commission considers including known loads as defined in the 2025 IEPR process in the demand forecast, continue to exclude them from the planning scenario; and
- Seek to identify and reduce barriers for geothermal development in and delivery to California.

II. INFORMATION ON NEW LOADS INCLUDED IN THE FORECAST SHOULD BE SOLICITED FROM ALL INFORMED STAKEHOLDERS BEFORE INCLUDING THEM IN THE FORECAST TO INFORM THE LIKELIHOOD AND TIMING OF LARGE LOADS

The Commission should capitalize on the knowledge and expertise of CCAs, along with other stakeholders, to verify the information received from IOUs regarding future loads, including data centers. CalCCA and its members appreciate the opportunities within the IEPR process to provide feedback to Commission staff and the openness of Commission staff to incorporate this feedback in its development of the Demand Forecast. CCAs can provide insight on and verification of future loads included in the proposed forecasts.

CCAs serve local communities and are well-positioned to evaluate new load growth given their unique access to information, either from large load customers or their local permitting agencies. Cities and counties have data on land use and building permits that can help inform the load forecast and each CCA's association with cities and counties will give it unique

access and insight into where new facilities are in their development and when they will be expected to be operational.

This insight is valuable, as information received by the IOUs is often insufficient to inform the IEPR Demand Forecast. For example, IOU energization dates alone are not a sufficient estimate as to when a project will come online, especially in the near term. Data centers with a 2027 energization date but have not started the permitting process would likely be delayed. In addition, energization requests to an IOU do not account for project feasibility. For example, in San Jose, assumed energization timing may be optimistic for data centers in the downtown area, which have additional permitting considerations. Additionally, as CCAs are community-based, CCA staff and local partners have the unique ability to personally observe the progress of any large load construction or build out. What is observed – and verified by local permitting status – may not align with IOU information. Lastly, actual usage of requested capacity may also differ by area, and a single assumption may not adequately reflect these differences. CalCCA urges the Commission to make ample use of the information community-based LSEs such as CCAs can provide.

To ensure all informed parties can provide insight into and verification of proposed forecasts, the Commission should strive to make as much data public as possible before it is relied upon in the IEPR Demand Forecast. Historically, it has not been possible for CCAs and data center customers to validate the information provided by the IOUs before it is used in the IEPR because it is submitted confidentially. CCAs have observed that once they do receive the data, it is often duplicative and/or contains errors. For example, upon notification that five of eight interconnection applications in a CCA service area were expected to be data centers, one

CCA's investigation found that of the five data center applications, three were not in their service area and two were scaled down to smaller, non-data center loads.

The CEC should therefore either require the data be shared with CCAs or request information from both IOUs and CCAs and validate the information for consistency. Given reliability and cost implications of forecasting new loads, ensuring all informed stakeholders can review the data before it is used in the IEPR Demand Forecast is necessary to ensure the forecast is as accurate as possible.

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

As described in Section II., increased transparency and data sharing across the Commission, CCAs, IOUs, and data center customers is imperative to informing the likelihood and timing of data center loads. While this data sharing may be sufficient for longer term planning (e.g., transmission planning) where the specific generation provider need not be known, when it comes to allocating LSE obligations associated with data center load for procurement purposes, a formal process is necessary for allocating data center load based upon predefined milestones.

For this reason, CalCCA filed a proposal in the CPUC's R.25-10-003 for the unique treatment of data center loads in the RA allocation process.³ This proposal is intended to maintain the collaborative process between the CEC and CPUC, in which the CEC continues to forecast peak demand, and data centers' portion of the forecast, and make LSE specific adjustments. For the purposes of allocating RA requirements, the proposal would establish a new process for allocating new data center loads separate from the existing process used to allocate

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

all other loads. This new process should include the following components: (1) considering data center load separately from other forecasted load for RA purposes, using actual rather than forecasted load to determine RA obligations; and (2) allocating an RA obligation to an LSE serving a data center when certain milestones, such as having chosen a LSE generation provider, having an executed interconnection agreement, and having begun construction, are met.

Establishing this new process is necessary to protect existing customers from absorbing costs associated with data center load. In particular, a process should be developed to identify the LSE that will serve the data center load and allocate RA obligations accordingly. Accounting for data center load on an individual basis for RA allocation purposes can therefore mitigate the risk of load forecast inaccuracy. By allocating data center load to the correct LSE with a high degree of certainty, as opposed to the “peanut butter” approach, this proposal has the added benefit of reducing potential cost-shifts between LSEs that experience substantial load growth associated with particular data centers (and are thus able to recover capacity costs from those data centers via rates) and other LSEs that are not.

This proposal also avoids the need to assume which LSE will serve the data center load for the purposes of RA allocations. CCAs are default providers, and they are willing and able to serve data center loads in their territories; some already serve these loads. Their intent to serve data center load does not mean that all customers will choose the CCA as their generation provider.

If there is a delay in implementing CalCCA’s proposed approach, the Commission should allow for further discussion around how opt-out assumptions should be developed for large loads. For example, the Commission has provided data center load by CCA in GWh, but not by number of customers. Because opt-outs occur based upon number of customers, access to this data by number of customers would be helpful in informing how to best develop opt out assumptions.

IV. TO THE EXTENT THE COMMISSION CONSIDERS INCLUDING KNOWN LOADS AS DEFINED IN THE 2025 IEPR PROCESS IN THE DEMAND FORECAST, IT SHOULD CONTINUE TO EXCLUDE THEM FROM THE PLANNING SCENARIO

To the extent the Commission considers known loads as defined in the 2025 IEPR process in the Demand Forecast, it should continue to exclude them from the Planning Forecast, given the uncertainty of known loads and the intended purpose of the planning forecast. The known loads data is collected from each IOU, and reflects customer information regarding project capacity sector, energization data, and load profiles. Significant questions remain regarding the accuracy of the known loads information, as well as its appropriateness for inclusion in the Planning Forecast.

Known loads as defined in the 2025 IEPR process should be excluded from the Planning Forecast, given significant uncertainties related to these loads, including their actual energization dates, and the intended purpose of the Planning Forecast. Many of the known loads reported to the Commission by the IOUs include projects that require upstream capacity upgrades that could take several years to complete before a customer load can be energized. Other project timelines are dependent on customers, permitting agencies, or contractors to complete portions of the work. Other factors, such as supply chain delays and environmental reviews, could further delay energization times. It is also still unclear whether the known loads methodology has been properly adjusted to reflect the coincident peak or to resolve issues of duplication and other errors revealed during the 2025 IEPR process.

Beyond concerns about the quality of the known loads data set, issues about appropriateness of the assumptions for different use cases should be carefully considered. The primary use case of known loads data is to ensure sufficient distribution and local capacity to maintain reliability. Known loads are therefore may be appropriate to include in the Local

Reliability forecast. However, coincidence factors for this local use case are expected to differ from the coincidence factor for a use case based on system-wide demand. The Planning Forecast is applied to use cases driven by system-wide demand, as in RA requirements, bulk transmission planning, or integrated resource planning. As such, it is inappropriate to assume that the contribution of known loads to local reliability requirements would be the same as the contribution of known loads to the Planning Forecast used for system-wide requirements.

V. THE COMMISSION’S EXPLORATION OF GEOTHERMAL CHALLENGES AND OPPORTUNITIES SHOULD SEEK TO IDENTIFY AND REDUCE BARRIERS FOR GEOTHERMAL DEVELOPMENT IN AND DELIVERY TO CALIFORNIA

Geothermal resources have the potential to play a significant role in the State’s clean energy transition by providing clean baseload energy. CCAs have already procured and are interested in continuing to procure geothermal resources to support diverse and clean portfolios. For example, Sonoma Clean Power, in partnership with Sonoma and Mendocino counties, is leading the GeoZone initiative to develop 600 MW of next-generation geothermal energy.⁴ CCAs and other LSEs are also required to procure clean firm resources to comply with CPUC procurement orders, and the CPUC has included 3.4 GW of geothermal by 2045 in its Preferred System Plan (PSP).⁵

⁴ <https://sonomacleanpower.org/geozone>.

⁵ D.26-02-057, *Decision Requiring 2029-2032 Electric Resource Procurement and Transmitting Portfolios for 2026-2027 Transmission Planning Process*, R.25-06-019 (Mar. 5, 2026), at 60: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M601/K777/601777006.PDF>.

Despite strong interest from LSEs and signals from regulators expressing a desire for a diverse resource portfolio in the State, the CAISO’s interconnection queue does not reflect this diversity.

Projects available for near-term procurement are predominately solar and battery storage.

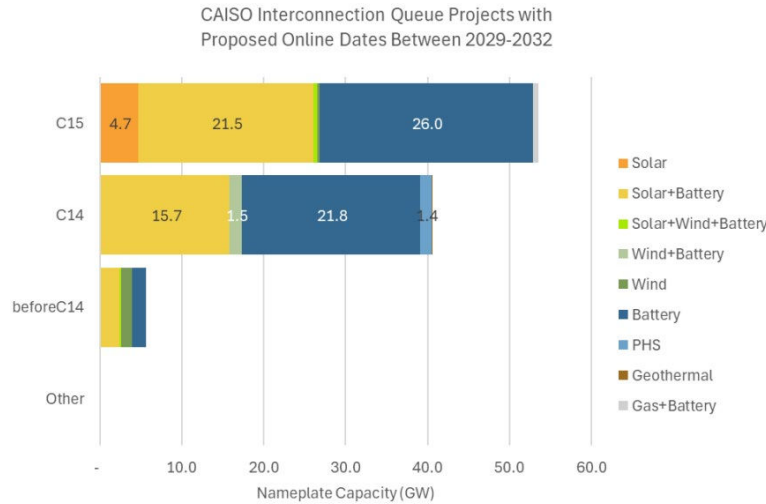


Figure 1. CAISO Interconnection Queue Projects with CODs between 2029 and 2032⁶

The current CAISO queue includes only two geothermal projects, totaling 62.5 MW.⁷ Outside of the CAISO, there are 894 MW of active geothermal interconnection requests in IID and another 824 MW in the non-California West.⁸ The CPUC’s recently adopted PSP includes geothermal levels far exceeding the amounts in the CAISO queue, including 1.2 GW by 2031 and 3.4 GW by 2045.⁹ The PSP also includes a significant amount of solar and storage, prompting questions around whether the “massive” amounts of solar and storage are feasible.¹⁰

⁶ CalCCA analysis of Berkeley Lab’s Queued Up dataset (2025) for CAISO, available at https://emp.lbl.gov/sites/default/files/2025-08/LBNL_Ix_Queue_Data_File_thru2024_v2.xlsx

⁷ CAISO Public Queue report: <https://www.aiso.com/documents/publicqueuereport.xlsx>; no geothermal projects are reported in the most recent Cluster 15 studies, available at <https://www.aiso.com/documents/cluster-15-interconnection-requests.xlsx>. ⁸ Based on CalCCA analysis of Berkeley Lab’s Queued Up dataset (2025) for non-CAISO interconnections in the West, available at https://emp.lbl.gov/sites/default/files/2025-08/LBNL_Ix_Queue_Data_File_thru2024_v2.xlsx

⁸ Based on CalCCA analysis of Berkeley Lab’s Queued Up dataset (2025) for non-CAISO interconnections in the West, available at https://emp.lbl.gov/sites/default/files/2025-08/LBNL_Ix_Queue_Data_File_thru2024_v2.xlsx

⁹ D.26-02-057, at 60.

¹⁰ D.26-02-057, at 80.

The combination of the lack of diversity in the CAISO queue and heavy reliance on solar and batteries in the CPUC's PSP suggest that investigating further the challenges and opportunities with developing geothermal is worthwhile.

The Commission should consult with relevant stakeholders to identify the magnitude and viability of geothermal opportunities in *and* out of state and investigate whether existing barriers are preventing the timely development of geothermal or other clean resources. *First*, the Commission should consult with LSEs and developers to identify areas of commercial interest within and outside of California to ensure the state is accurately planning to incorporate geothermal at viable locations. This information combined with the Commission's expertise in land use and the CPUC's efforts to map resources in the PSP will provide helpful insight into whether the State's planning processes align with commercial expectations.

Second, the Commission should also consult with developers to identify reasons why geothermal is not showing up in the CAISO queue in numbers consistent with the State's planning portfolios. Identifying root causes will help the Commission, other agencies, and stakeholders to identify solutions necessary to remove barriers. The Commission should also investigate the extent to which developers are seeking to develop geothermal outside the State. This should include the reasons for seeking development outside of California, and whether barriers, such as import capability, would prevent such out-of-state projects from offering that capacity to California LSEs.

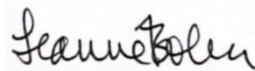
Finally, the Commission should examine siting and licensing requirements of the Commission and local entities to determine if they present any unnecessary barriers to geothermal development and the development of other clean energy resources. These efforts will

help the Commission identify potential solutions to the challenges the State is facing with bringing a diverse set of technologies to the system to support a reliable clean energy transition.

VI. CONCLUSION

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

Respectfully submitted,

A handwritten signature in black ink that reads "Leanne Bober". The signature is written in a cursive style with a large initial "L".

Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

March 25, 2026

APRIL FILINGS



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

FILED

04/01/26

04:59 PM

R1807005

Order Instituting Rulemaking to Consider
New Approaches to Disconnections and
Reconnections to Improve Energy Access
and Contain Costs.

R.18-07-005

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY
COMMENTS ON ASSIGNED COMMISSIONER'S RULING SETTING
WORKSHOP AND ORDERING COMMENTS**

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April 1, 2026

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SUMMARY OF RECOMMENDATIONS¹

CalCCA recommends the Commission:

- Reject IOU recommendations to increase or remove the disconnection rate caps because it would disrupt the lives of thousands of customers without addressing the underlying drivers of arrearages;
- Reject PG&E's recommendation to terminate as unnecessary any ongoing processes to consider addressing disconnections because the recommendation is contradicted by the realities of the affordability crisis;
- Reject the IOUs' recommendation to address customer protections on an ongoing basis only through advice letter processes because this limited process will not allow for sufficient intervenor and consumer group participation in crafting those customer protections;
- Consider party recommendations on PIPP, AMP, and the CBO pilot in the context of a consolidated customer support program to lower administrative burden;
- Continue testing PIPP-style programs to ensure continued and effective support to low-income customers; and
- Reject SDG&E's opposition to allowing customers in the AMP program to make partial payments because it ignores the potential for customers to improve bill payment consistency.

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

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

Order Instituting Rulemaking to Consider
New Approaches to Disconnections and
Reconnections to Improve Energy Access
and Contain Costs.

R.18-07-005

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY
COMMENTS ON ASSIGNED COMMISSIONER'S RULING SETTING
WORKSHOP AND ORDERING COMMENTS**

California Community Choice Association² (CalCCA) submits these Reply Comments pursuant to the *Assigned Commissioner's Ruling Setting Workshop and Ordering Comments*³ (Ruling), dated February 26, 2026. The Ruling seeks comments in response to the questions set forth in the Ruling and the information discussed during the March 11, 2026, Workshop (Workshop).

I. INTRODUCTION

Party Opening Comments present a diverse set of perspectives across investor-owned utilities (IOU) and consumer advocate groups. While many of the consumer advocate parties

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

³ *Assigned Commissioner's Ruling Setting Workshop and Ordering Comments*, Rulemaking (R.) 18-07-005 (Feb. 26, 2026). All references to Opening Comments refer to party opening comments to the Ruling, filed on or about March 25, 2026.

oppose raising or removing disconnection rate caps,⁴ Southern California Gas Company (SoCalGas), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the IOUs) continue to advocate for either significant increases to or removal of the caps.⁵ Proposals to raise or remove disconnection caps are unreasonable, harmful, and provide little rate benefit to customers in terms of reductions to arrearages when compared to addressing other cost drivers. In contrast to CalCCA Opening Comments recommending a successor rulemaking to continue to discuss the future of customer disconnection protections,⁶ PG&E believes no additional discussion is necessary regarding program updates or further development of customer protections.⁷ In addition, PG&E and SCE propose Tier 2 advice letter processes for making modifications to disconnection rate caps.⁸ Echoing the Joint Consumers Opening Comments, this process would not provide sufficient opportunity for intervenors to perform discovery and review the impacts of proposed changes.⁹ The volume of open questions in the Ruling and the clear disagreement among parties as to what solutions should be, points to the need for further discussion among the California Public Utilities Commission (Commission) and stakeholders. Therefore, the best solution is to create a successor rulemaking.

⁴ Center for Biological Diversity (CBD) Opening Comments, at 5; Public Advocates Office (Cal Advocates) Opening Comments, at 1; The Utility Reform Network (TURN), Center for Accessible Technology (CforAT), and National Consumer Law Center) (collectively Joint Consumers) Opening Comments, at 4.

⁵ SoCalGas Opening Comments, at 3; PG&E Opening Comments, at 2; SCE Opening Comments, at 8; SDG&E Opening Comments, at 5.

⁶ CalCCA Opening Comments, at 5.

⁷ PG&E Opening Comments, at 17-18 (suggesting an ongoing process or working group would create unnecessary additional costs for customers).

⁸ PG&E Opening Comments, at 5; SCE Opening Comments, at 9.

⁹ Joint Consumers Opening Comments, at 9.

Additionally, Opening Comments present a myriad of recommendations for the Percentage of Income Payment Plan (PIPP) Pilot, the Arrearage Management Plan (AMP) Pilot, and the Community-Based Organization (CBO) Pilot. The Commission should consider consolidating these customer assistance programs into an umbrella assistance program to more efficiently offer services to vulnerable customers and streamline the administrative needs of the currently separate programs. This would facilitate making adjustments to PIPP, which the IOUs oppose extending into a permanent program for customers.¹⁰ The proposals to discontinue PIPP rely on the pilot’s results presented in the PIPP Evaluation, which states that the pilot has not yet met all of its goals.¹¹ Instead of discontinuing the program, these results should motivate adjustments to continue to offer payment assistance to low-income customers.

Finally, SDG&E mischaracterizes the proposal to allow partial payments in AMP to count toward arrearage forgiveness, or at least prevent removal from the program. SDG&E believes that it “would not promote positive payment behavior among participants.”¹² This view ignores the structure of AMP, which emphasizes making consistent, on-time payments, as well as the reality that electric bills are high, even for customers in the California Alternative Rates for Energy (CARE) program. Partial payments would still support making payments consistently and on time.

In summary, CalCCA recommends the Commission:

- Reject IOU recommendations to increase or remove the disconnection rate caps because it would disrupt the lives of thousands of customers without addressing the underlying drivers of arrearages;

¹⁰ SoCalGas Opening Comments, at 12; PG&E Opening Comments, at 13; SCE Opening Comments, at 16; SDG&E Opening Comments, at 16.

¹¹ *Percentage of Income Payment Plan Pilot Program Final Evaluation Report (PIPP Evaluation)*, R.18-07-005 (Mar. 17, 2025), at Attachment A, viii, Research Question 10.

¹² SDG&E Opening Comments, at 15.

- Reject PG&E’s recommendation to terminate as unnecessary any ongoing processes to consider addressing disconnections because the recommendation is contradicted by the realities of the affordability crisis;
- Reject the IOUs’ recommendation to address customer protections on an ongoing basis only through advice letter processes because this limited process will not allow for sufficient intervenor and consumer group participation in crafting those customer protections;
- Consider party recommendations on PIPP, AMP, and the CBO pilot in the context of a consolidated customer support program to lower administrative burden;
- Continue testing PIPP-style programs to ensure continued and effective support to low-income customers; and
- Reject SDG&E’s opposition to allowing customers in the AMP program to make partial payments because it ignores the potential for customers to improve bill payment consistency.

II. IOU RECOMMENDATIONS TO INCREASE OR REMOVE THE DISCONNECTION RATE CAPS WOULD CAUSE UNNECESSARY HARM FOR LITTLE BENEFIT AND SHOULD BE REJECTED

Recommendations from the IOUs to increase or remove disconnection rate caps would provide little benefit, cause unnecessary harm, and should be rejected.¹³ While these parties provide varying degrees of support for the increase of disconnection rate caps, the potential harm of increasing disconnections at this time greatly outweighs the potential benefits. In Opening Comments, SCE estimates that in 2025, arrearages cost non-CARE customers \$24 per year.¹⁴ To put this into perspective, SCE’s website estimates a monthly bill of \$196.48 for a non-CARE residential customer, or \$2357.76 annually. This means that SCE’s estimated carrying cost to customers of arrearages is one percent of the total annual cost. Therefore, if SCE cut arrearages in half through disconnecting more customers, this would provide a *half-percent* annual savings

¹³ SoCalGas Opening Comments, at 3; PG&E Opening Comments, at 2; SCE Opening Comments, at 8; SDG&E Opening Comments, at 5.

¹⁴ SCE Opening Comments, at 2 (stating that SCE estimates arrearages caused an estimated bill increase of \$2 per month for non-CARE customers).

to other customers. At the same time, *tens of thousands* of customers would experience disconnections, which, as CalCCA pointed out in Opening Comments, disproportionately impact Black, Latino, low-income customers, as well as renters. All of these customers are specifically targeted in the Commission’s Environmental and Social Justice Action Plan.¹⁵ In addition, annual fluctuations of IOU rates can easily undo any bill savings from reducing arrearage carrying costs.¹⁶ This is yet another indication that arrearages are not the primary driver of residential rates. Disconnections are an inefficient and harmful way to lower customer bills, and the Commission should therefore reject proposals to increase the disconnection rate caps.

III. PG&E’S RECOMMENDATION TO TERMINATE ANY ONGOING PROCESSES TO CONSIDER ADDRESSING DISCONNECTIONS SHOULD BE REJECTED BECAUSE IT IS CONTRADICTED BY THE CLEAR NEED FOR IMPROVEMENTS TO CUSTOMER PROTECTIONS

The Commission should dismiss PG&E’s recommendation to terminate any ongoing processes to consider addressing disconnections given the realities of the current electric rate affordability crisis and by the activities in this proceeding. PG&E states in Opening Comments that:

[t]he Commission should not order an ongoing process or working group to consider and develop best practices to address factors that increase risk of disconnection or limit reconnections. The Commission opened this rulemaking proceeding nearly eight years ago to adopt rules and policies that reduce disconnections and improve reconnection processes and outcomes for disconnected customers. Since 2018, parties have provided feedback via rulings, workshops, and more, building a very robust record. An ongoing

¹⁵ CalCCA Opening Comments, at 7-8.

¹⁶ See SCE AL 5449-E, *Final Implementation of Southern California Edison Company’s Consolidated Revenue Requirement and Rate Change on January 1, 2025* (Dec. 30, 2024), at 29 (stating SCE’s bundled residential rates increased 1.4 percent from 2024 to 2025); see also SCE AL 5725-E, *Final Implementation of Southern California Edison Company’s Consolidated Revenue Requirement and Rate Change on January 1, 2026* (Dec. 30, 2025), at 30 (stating SCE’s bundled residential rates decreased 2.9 percent from 2025 to 2026).

process or working group would create unnecessary additional costs for customers.¹⁷

PG&E appears to believe that the problems this proceeding was opened to address are all solved. However, the volume of questions in the Ruling directly contradicts this conclusion. Many open questions remain that require time and attention from a diverse set of stakeholders. An ongoing process, such as a successor rulemaking to consider customer protections, would not represent an “unnecessary additional cost for customers.” On the contrary, it is *very* necessary, given that rates and arrearages are still high, to use resources to improve customer support and protection programs. Therefore, the Commission should continue to discuss and improve customer protections and address arrearages in a successor rulemaking.

IV. THE IOUS RECOMMENDATION THAT THE COMMISSION ADDRESS FUTURE CUSTOMER PROTECTIONS THROUGH IOU ADVICE LETTER FILINGS FAILS TO ALLOW SUFFICIENT INTERVENOR AND CONSUMER GROUP PARTICIPATION AND INTERVENTION IN DEVELOPING SUCH PROTECTIONS

The Commission should reject IOU recommendations to modify vital customer protections merely through Advice Letter processes because this process will not provide sufficient opportunities for intervenors and consumer groups to participate and intervene in developing such programs. PG&E and SCE recommend using the Advice Letter process regarding raising disconnection caps.¹⁸ CalCCA agrees with the Joint Consumers’ recommendation that the IOUs’ Advice Letter proposals be rejected. First, Advice Letters create a context in which proposals are fundamentally shaped by the IOUs through the submission of the Advice Letters.¹⁹ Second, for Tier Two Advice Letters, as proposed by SCE, no opportunity

¹⁷ PG&E Opening Comments, at 17-18.

¹⁸ PG&E Opening Comments, at 5 (responding to question five of the Ruling); SCE Opening Comments, at 5 (proposing that changes to disconnection rate caps be implemented through a Tier Two Advice Letter process).

¹⁹ See Joint Consumers Opening Comments, at 9.

exists for competing proposals from other parties.²⁰ Lastly, an Advice Letter process will not result in a Commission action allowing requests for intervenor compensation, on which many consumer groups rely.²¹ Therefore, the Commission should not adopt an Advice Letter process for potential updates to disconnection-related policies or programs and instead do so through a successor rulemaking or a consolidated application proceeding with all IOUs.

V. THE COMMISSION SHOULD CONSIDER PROPOSALS FOR AMP, PIPP, AND THE CBO PILOT IN THE CONTEXT OF A CONSOLIDATED CUSTOMER SUPPORT PROGRAM TO LOWER THE ADMINISTRATIVE BURDEN

Party proposals on PIPP, AMP, and the CBO Pilot in response to the Ruling demonstrate the wide array of positions on the future of those pilot programs, and the Commission should consider the feedback in the context of a consolidated customer support program. For example, regarding PIPP, the Joint Consumers argue that a future version of PIPP should only be for medical baseline customers.²² Utility Consumers' Action Network (UCAN) argues PIPP should be geographically limited and have stricter income qualification standards.²³ UCAN and CBD argue for shareholders to cover the cost of a future version of PIPP.²⁴ The IOUs oppose a future version of PIPP altogether.²⁵ The Commission has much to consider regarding improvements to AMP, PIPP, and the CBO Pilot. Consolidation of these customer assistance programs would still allow for making updates to improve program goal attainment, such as arrearage forgiveness, paying bills on time, and reducing the risk of disconnections. Consolidation could also reveal synergies across the programs. For example, the PIPP Evaluation concludes that the benefits

²⁰ *Ibid.*

²¹ *Ibid.*

²² Joint Consumers Opening Comments, at 18.

²³ UCAN Opening Comments, at 26

²⁴ *Ibid.*; CBD Opening Comments, at 19.

²⁵ SoCalGas Opening Comments, at 2; PG&E Opening Comments, at 13; SCE Opening Comments, at 16; SDG&E Opening Comments, at 16.

provided by AMP and PIPP are complementary. AMP incentivizes customers to pay their bills on time, and PIPP provides bill assistance to help customers afford bills.²⁶ Some customers may only need one of these benefits, but others may need both. Additionally, the informational and educational benefits offered by the CBO Pilot, which connects customers with local CBOs to provide education on assistance options, can act as the initial outreach, education, and enrollment arm of an umbrella customer assistance program. An umbrella program can consolidate and streamline administrative costs and ensure that customers get the assistance they need, as customer information will no longer be separated across multiple program databases. Such a new, consolidated customer assistance program should be discussed in a successor rulemaking.

VI. PIPP-STYLE PROGRAMS SHOULD CONTINUE AS THEY PROVIDE MUCH-NEEDED SUPPORT TO LOW-INCOME CUSTOMERS

Regardless of the potential consolidation as recommended above, the Commission should continue to test low-income payment options on variations of the PIPP model. The IOUs recommend in Opening Comments that PIPP should not be extended beyond its original sunset date,²⁷ primarily because of the findings in the PIPP Evaluation that PIPP has not met all of its intended goals.²⁸ PG&E reasonably points out that it is not equipped to perform detailed income verification beyond PIPP's current practices,²⁹ which may be true for the other IOUs as well. Obstacles and underwhelming mid-term evaluation results, however, should not deter the Commission from attempting to provide bill assistance to low-income customers. These obstacles and results only indicate that a different approach should be tested. Continued

²⁶ PIPP Evaluation, Attachment A, at 72 (recommending a joint program that provides both energy bill payment assistance and arrearage forgiveness).

²⁷ SoCalGas Opening Comments, at 12; PG&E Opening Comments, at 13; SCE Opening Comments, at 16; SDG&E Opening Comment, at 16.

²⁸ PIPP Evaluation, Attachment A, at viii, Research Question 10.

²⁹ PG&E Opening Comments, at 14.

adjustments to PIPP are a perfect example of why a successor rulemaking is needed to provide further discussion on how to make the low-income bill assistance offered by PIPP work better.

For example, PG&E's critique of income verification is legitimate and should be further explored. The Base Services Charge Income Verification Working Group Report demonstrates the complexities of large-scale income verification.³⁰ In theory, PIPP works by identifying low-income customers to cap their energy burden. In practice, however, PIPP only identifies two average income levels to enable two levels of bill caps.³¹ This means that participating customers' energy burdens will either remain too high, or will become lower than is targeted. These complexities, however, are not sufficient justification for terminating support for vulnerable customers.

Targeted questions like how to overcome the tension between income verification and providing the right amount of bill assistance will help parties develop targeted solutions. As suggested by UCAN, the Commission and stakeholders can evaluate PIPP and assistance programs from other states to find solutions.³² The Commission should consider these proposals and targeted questions to resolve the critiques presented by the PIPP Evaluation throughout the rest of this proceeding and/or in a successor rulemaking.

VII. SDG&E'S OPPOSITION TO ALLOWING PARTIAL PAYMENTS IN AMP SHOULD BE DISMISSED BECAUSE PARTIAL PAYMENTS STILL INCENTIVIZE MAKING PAYMENTS CONSISTENTLY AND ON TIME

SDG&E's opposition to allowing partial AMP payments based on its conclusion that such partial payments do not promote positive payment behaviors should be rejected. SDG&E disagrees with CalCCA's and the Joint Consumers' recommendation to allow customers making

³⁰ See *Income Verification Process Working Group Final Report* (Jan. 15, 2026).

³¹ PIPP Evaluation, Attachment A, at 5 (describing PIPP's program design of caps).

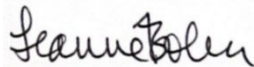
³² UCAN Opening Comments, at 29.

partial, on-time, payments to stay in the AMP program.³³ SDG&E states that doing so, “would not promote positive payment behavior among participants.”³⁴ SDG&E provides no further details to back up this assertion. This position is unsubstantiated and should be dismissed. AMP’s purpose and structure clearly emphasize the desired behavior from customers: making payments consistently and on time. Allowing partial payments to count toward arrearage forgiveness in AMP, or at least preventing unenrollment from the program, provides customers an opportunity to make good-faith payments even when they cannot afford the full amount. The Commission should continue to consider adjustments to AMP to further provide customer assistance in managing arrearages.

VIII. CONCLUSION

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

Respectfully submitted,



Leanne Bober,
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General Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

April 1, 2026

³³ SDG&E Opening Comments, at 15.

³⁴ *Ibid.*